No. 23A-

In the

Supreme Court of the United States

KINDER MORGAN, INC.; ENBRIDGE (U.S.) INC.; TRANSCANADA PIPELINE USA LTD.; INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; AMERICAN PETROLEUM INSTITUTE,

Applicants,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

On Emergency Application for Stay to the Honorable John G. Roberts, Jr., Chief Justice and Circuit Justice for the U.S. Court of Appeals for the District of Columbia Circuit

EMERGENCY APPLICATION FOR STAY OF FINAL AGENCY ACTION DURING PENDENCY OF PETITIONS FOR REVIEW

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RULE 29.6 STATEMENT

Kinder Morgan is a publicly held corporation. Kinder Morgan does not have a parent corporation, and no publicly held corporation holds 10% or more of Kinder Morgan's stock.

Enbridge (U.S.) Inc. is a wholly-owned subsidiary of Enbridge Inc., a diversified energy company headquartered in Calgary, Canada. Enbridge (U.S.) Inc.'s holdings include natural gas pipelines regulated by the Federal Energy Regulatory Commission. Enbridge Inc. is a publicly traded company that trades on the New York and Toronto stock exchanges. Enbridge, Inc. has no parent companies, and no publicly held company owns a 10 percent or greater interest in Enbridge, Inc.

TransCanada PipeLine USA Ltd. is an indirectly owned subsidiary of TC Energy Corporation. TC Energy Corporation is a federally registered Canadian corporation, with its headquarters in Calgary, Alberta. TC Energy Corporation is a publicly held corporation with no parent corporation. No entity (whether publicly or privately held) has an ownership interest in TC Energy Corporation of 10% or more.

Interstate Natural Gas Association of America ("INGAA") hereby states that INGAA is a national trade association that represents interstate natural gas transmission pipeline companies. INGAA has no parent corporation, and no publicly held corporation has a 10% or greater ownership in INGAA.

American Petroleum Institute ("API") hereby states that API is a national trade association that represents all segments of America's natural gas and oil industry. API has no parent corporation, and no publicly held corporation has a 10% or greater ownership in API.

PARTIES TO THE PROCEEDINGS

The parties to D.C. Circuit Case No. 23-1157 (lead case), consolidated with Case Nos. 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1207, 23-1208, 23-1209, and 23-1211 are listed below:

Applicant Kinder Morgan, Inc. is Petitioner in Case No. 23-1181; Applicants Interstate Natural Gas Association of America and American Petroleum Institute are Petitioners in Case No. 23-1193; Applicant Enbridge (U.S.) Inc. is Petitioner in Case No. 23-1202; and Applicant TransCanada PipeLine USA Ltd. is Petitioner in Case No. 23-1205.

Respondent State of Utah is Petitioner in Case No. 23-1157.

Respondents States of Ohio, Indiana, and West Virginia are Petitioners in Case No. 23-1183.

Respondent American Forest and Paper Association is Petitioner in Case No. 23-1190.

Respondent Midwest Ozone Group is Petitioner in Case No. 23-1191.

Respondents Associated Electric Cooperative, Inc.; Ohio Valley Electric Corporation; Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance; America's Power; National Rural Electrification Cooperative Association; and Portland Cement Association are Petitioners in Case No. 23-1195.

Respondent National Mining Association is Petitioner in Case No. 23-1199.

Respondent American Iron and Steel Institute is Petitioner in Case No. 23-1200.

Respondent State of Wisconsin is Petitioner in Case No. 23-1201.

Respondent American Chemistry Council is Petitioner in Case No. 23-1203.

Respondent Hybar LLC is Petitioner in Case No. 23-1206.

Respondent U.S. Steel Corporation is Petitioner in Case No. 23-1207.

Respondent Union Electric Company d/b/a Ameren Missouri is Petitioner in Case No. 23-1208.

Respondent State of Nevada is Petitioner in Case No. 23-1209.

Respondent Arkansas League of Good Neighbors is Petitioner in Case No. 23-1211.

Respondent City Utilities of Springfield, Missouri is Intervenor for Petitioners in the consolidated cases.

Respondents the United States Environmental Protection Agency and Michael S. Regan, Administrator U.S. EPA, are Respondents in all consolidated cases listed above.

Respondents City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin; Air Alliance Houston; Appalachian Mountain Club; Center for Biological Diversity; Chesapeake Bay Foundation; Citizens for Pennsylvania's Future; Clean Air Council; Clean Wisconsin; Downwinders at Risk; Environmental Defense Fund; Louisiana Environmental Action Network; Sierra Club; Southern Utah Wilderness Alliance; and Utah Physicians for a Healthy Environment are Intervenors for Respondent, U.S. EPA.

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TO THE HONORABLE JOHN G. ROBERTS, JR.,
CHIEF JUSTICE OF THE SUPREME COURT AND
CIRCUIT JUSTICE FOR THE D.C. CIRCUIT:

Applicants Kinder Morgan, Inc., Enbridge (U.S.) Inc., TransCanada PipeLine USA Ltd., Interstate Natural Gas Association of America, and American Petroleum Institute, respectfully ask this Court to immediately stay the effectiveness of the final rule (Rule) of the United States Environmental Protection Agency (EPA) entitled *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards*, 88 Fed Reg. 36,654 (June 5, 2023) as it applies to engines used for pipeline transportation of natural gas. The Applicants have petitioned for review of the Rule in the United States Court of Appeals for the District of Columbia Circuit and filed stay motions in that court requesting that the Rule's applicability to pipeline engines be stayed pending judicial review. In a split decision, the D.C. Circuit denied these and other stay motions on September 25, 2023.

INTRODUCTION

In the Rule, EPA established a uniform, federal program to enforce stringent emissions limits for 23 States that may be contributing to increased pollution levels in nearby States. Consistent with similar past rulemakings, the Rule requires operators of power plants within those States to implement control technologies to reduce emissions. The Rule also, for the first time, reaches into 20 states to regulate gas-fired reciprocating internal combustion engines (pipeline engines) used to efficiently transport natural gas along pipelines across the United States.

The Applicants and their members own and operate hundreds of thousands of miles of natural gas pipelines and transport the vast majority of natural gas consumed in the

United States. The Rule requires that thousands of pipeline engines achieve certain emission-rates limits by May 1, 2026. This date is flat-out impossible for all subject pipeline engines to achieve. Indeed, even to make progress on achieving compliance by that date, operators must significantly impair their ability to serve residential and commercial natural gas and electric power demand across the United States in the short term—making it all the more remarkable that EPA made no effort to even discuss the impacts of its Rule with the Federal Energy Regulatory Commission, the agency charged with ensuring the safe and reliable transportation of natural gas.

Applicants are entitled to a stay pending appeal because: they are likely to succeed on the merits; they will suffer irreparable injury absent a stay; and the balance of harms and public interest favors a stay.

As a threshold matter, EPA had to disapprove over 20 state implementation plans before the agency could adopt its national Rule. EPA's disapprovals of those state plans are currently under challenge in seven federal circuits, and *every one of those courts* has stayed EPA's disapproval of the underlying state plans. Yet EPA continues to implement the Rule—no longer a uniform, national rule—despite it being stayed in a majority of the states in which it was meant to apply.

On top of this foundational flaw, EPA violated the Clean Air Act and the Administrative Procedure Act by: failing to identify the "amounts" of emissions from pipeline engines under the Clean Air Act that significantly contribute to nonattainment or interfere with maintenance in a downwind state; failing to comport with past practice; and failing to justify its approach. And on top of that, EPA adopted an overly broad applicability criterion for pipeline engines that is inconsistent with its own definition of sources that "significantly contribute."

Taken together, this Rule's fundamental predicate *and* substantive particulars are lacking. If this Rule is not arbitrary and capricious, no rule is.

If this Court does not stay the Rule, there will be natural gas supply interruptions while the courts consider the legality of the Rule and operators struggle to bring pipeline engines into compliance with an arbitrary standard. Add the enormous compliance costs of nearly one billion dollars that Applicants will bear over that period, and the Rule causes the exact type of irreparable injury that merits a stay.

Finally, the public interest favors a stay. An agency's compliance with the law is always in the public interest. And, unless stayed, EPA's unlawful rule threatens disruption to a reliable supply of natural gas for customers throughout the country, including for heating and cooking in homes and businesses, as a fuel for electric power generation, and as a critical input in industrial processes.

Applicants support sensible emissions regulations of pipeline engines; but EPA's arbitrary and capricious Rule leaves pipeline engine operators only two choices: (1) be out of compliance with EPA's Rule; or (2) restrict transportation of natural gas, at grave costs to the public. Applicants urge this Court to stay the Rule so they can continue to reliably serve this country's natural gas demand.

STATEMENT

A. Statutory And Regulatory Background

1. The Clean Air Act is a fundamentally federalist statute: it tasks EPA with setting national air quality standards and tasks states with implementing those standards in the first instance through state implementation plans. *See* 42 U.S.C. §§ 7409(a), 7410(a)(2)(C). As "long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation." *Train v. Nat. Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975). If—and only if—a State declines to submit a plan, or if the State's plan does not satisfy the federal standards, EPA promulgates a federal plan in its stead. *Id.* § 7410(c)(1). Relevant here, the Act requires state plans to prohibit sources "within the State from emitting any air pollutant in amounts" that will "contribute significantly" to another State's nonattainment, or interfere with maintenance, of the national standards. *Id.* § 7410(a)(2)(D)(i). This statutory requirement has been referred to as the "good neighbor" provision, or the "transport" provision.

To implement this directive, EPA uses modeling and data from "receptors" that monitor air quality throughout the country to identify the downwind States expected to have problems attaining or maintaining the national standards, and the upwind States that contribute emissions to those downwind receptors. *See* 88 Fed. Reg. at 36,659; *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 500 (2014). To determine which upwind emissions must be eliminated because they "contribute significantly" to downwind nonattainment, EPA considers the cost of reducing the emissions and the impact it will have on downwind air quality. 88 Fed. Reg. at 36,660. "EPA's task is to reduce upwind pollution, but only in 'amounts' that push a downwind State's pollution concentrations above the relevant [air quality standard]." *EME Homer City Generation*, 572 U.S. at 514; *see also* 88 Fed. Reg. at 36,676 (EPA defining "amounts" to mean the "amount of emissions that is in excess of the emissions control strategies that EPA has deemed cost-effective"). Identifying a specific "amounts" threshold is therefore imperative to comply with the transport provision.

In an earlier transport rule, *see* 88 Fed. Reg. at 36,668–69, EPA determined that an upwind State's emissions "'contribute[d] significantly' to downwind nonattainment to the extent its exported pollution both (1) produced one percent or more of a[n] [air-quality standard] in at least one downwind State"; and "(2) could be eliminated most cost-effectively as determined by EPA." *EME Homer*, 572 U.S. at 502–503. Thus, "[a]s EPA interprets the statute, upwind emissions rank as 'amounts [that] . . . contribute significantly to nonattainment' if they . . . can be eliminated under the cost threshold set by the Agency." *Id.* at 518. This Court upheld that approach, concluding that eliminating "amounts that can cost-effectively be reduced is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address." *Id.* at 519.

This Court made clear, however, 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." *Id.* at 521. If EPA were to engage in such "over-control," it "will have overstepped its authority." *Id.* at 521–22.

2. In October 2015, EPA promulgated a new, more stringent national air-quality standard for ozone. *See* 88 Fed. Reg. at 36,656. The new ozone standard triggered a duty on

upwind States to revise their state plans to restrict NOx emissions, a precursor to ozone.[1] Under the Clean Air Act, states then had three years to submit their state plans to EPA for approval—meaning the state plans needed to be submitted in 2018. Many states submitted their plans by this deadline or soon thereafter.

EPA did not act expeditiously on the state plans submitted to it by that 2018 statutory deadline: It was not until February 2023—nearly five years later—that the agency announced its decision to disapprove those submissions. *Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, 88 Fed. Reg. 9,336 (Feb. 13, 2023). EPA concluded that 23 States did not adequately discharge their obligations under the transport provision of the Act. 88 Fed. Reg. at 36,656. Then, a few months later, EPA issued the Rule establishing its own federal plan to restrict NOx emissions from sources in all 23 States. *Id.*[2]

As relevant here, and for the first time, the Rule directly regulates reciprocating internal combustion engines used in pipeline transportation of natural gas. 88 Fed. Reg. at 36,659.[3] For pipeline engines, EPA imposed emissions limits after examining the available emissions-control technologies and allegedly selected the "cost threshold" that it found "in

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1 Nitrogen oxides—"NOx"—are a type of pollutant formed by atmospheric nitrogen during combustion. NOx can combine with other pollutants in the presence of sunlight to form ozone.

2 The Rule is provided in the Appendix at 1a. Notably, EPA proposed the Rule well before it even disapproved the state plans. *See Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, 87 Fed. Reg. 20,036 (proposed Apr. 6, 2022).

3 The Rule also regulates electric generating units (EGUs) and certain industrial sources (non-EGUs), of which pipeline engines are one.

general, maximized cost-effectiveness—*i.e.*, that achieved a reasonable balance of incremental NOx reduction potential and corresponding downwind air quality improvements" relative to other possible reductions. *Id.* at 36,678. "Taken together," the agency stated, the Rule's emissions limits "will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone [standard]." *Id.* at 36,657. But EPA abandoned its cost threshold in the final Rule while nonetheless requiring the same emission control strategies for industrial sources resulting from that abandoned cost analysis.

The Rule now limits emissions from pipeline engines with a "nameplate rating" of 1,000 horsepower or greater. 40 C.F.R. § 52.41(b). The specific limitations vary based on the type of engine, but each caps the grams of NOx that can be emitted per horsepower-hour. *Id.* § 52.41(c). In arriving at the 1,000-horsepower applicability criterion for pipeline engines, EPA deviated from its approach for several other industrial sources, where EPA used actual emissions amounts exceeding 100 tons per year. Despite wide variance in actual emissions from pipeline engines greater than 1,000 horsepower, EPA contends that the horsepower criterion "reasonably approximates" the 100-ton-per-year applicability criterion that EPA used for other industrial sources. 88 Fed. Reg. at 36,820.

The Rule also sets an impossible compliance deadline given the scale and scope of requirements for pipeline engines. All regulated pipeline engines are required to meet the applicable emissions rate limits by May 1, 2026, less than three years after the Rule's effective date. EPA rationalized this compliance date in part by contending that the *proposed* rule had provided "roughly an additional year of notice." *Id.* at 36,755.

Tacitly acknowledging the Rule's overly broad application, costly requirements, and impossible compliance timeline, EPA tacked on provisions (not proposed at the draft stage) purportedly allowing for one-off exceptions or limited flexibility. Operators may attempt to seek EPA's discretionary approval, on "a case-by-case" basis, for a higher emissions limit for an engine that cannot comply with the applicable limit "due to technical impossibility or extreme economic hardship." 40 C.F.R. § 52.40(e). Operators also may attempt to seek EPA approval for a "Facility-Wide Averaging Plan as an alternative means of compliance," provided that the "total emissions reductions" for all the engines in the facility are "equivalent to or greater than those" that would be achieved if each engine hit its individual limit. *Id.* § 52.41(d). For pipeline engines, EPA may grant a case-by-case compliance extension for units that cannot meet the applicable compliance date "due to circumstances entirely beyond the owner or operator's control" if the owner or operator demonstrates it "has taken all steps possible to install the controls necessary for compliance . . . by the applicable compliance date." *Id.* § 52.40(d)(3).

3. EPA's disapproval of the state plans—the predicate for the nationwide Rule—has been challenged in seven different federal circuit courts. *All seven* have stayed EPA's underlying state plan disapprovals.[4] Acknowledging these stays, EPA has issued two "interim final

[4] Order, *Texas v. EPA*, No. 23-60069, ECF 269-1 (5th Cir. May 1, 2023); Order, *Arkansas v. EPA*, No. 23-1320, ECF 5280996 (8th Cir. May 25, 2023); Order, *Missouri v. EPA*, No. 23-1719, ECF 5281126 (8th Cir. May 26, 2023); Order, *Texas v. EPA*, No. 23-60069, ECF 359-2 (5th Cir. June 8, 2023); Order, *Nevada Cement Co. v. EPA*, No. 23-682, ECF 27.1 (9th Cir. July 3, 2023); Order, *ALLETE, Inc. v. EPA*, No. 23-1776 (8th Cir. July 5, 2023); Order, *Kentucky v. EPA*, No. 23-3216, ECF 39-2 (6th Cir. July 25, 2023); Order, *Utah v. EPA*, No. 23-9509, ECF 010110895101 (10th Cir. July 27, 2023); Interim Stay Order, *West Virginia v. EPA*, No. 23-01418, ECF 39 (4th Cir. Aug. 10, 2023); Order, *Alabama v. EPA*, No. 23-11173 (11th Cir. Aug. 17, 2023). This uniform response from the federal courts of appeals reinforces the primacy

rules" to stay the Rule within the twelve states where the state plan disapprovals have been stayed. *See Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States*, 88 Fed. Reg. 49,295 (July 31, 2023) (First Interim Final Rule)[5]; *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Additional Judicial Stays of SIP Disapproval Action for Certain States,* 88 Fed. Reg. 67,102, 67,103 (Sept. 29, 2023) (Second Interim Final Rule). EPA has not expressly extended the compliance deadline for pipeline engines in states with stays, however, creating yet more regulatory uncertainty for operators attempting to manage an already impossible timeline. *See* 88 Fed. Reg. at 67,103–04 (stating only that EPA "generally anticipates" that lead times would be "comparable" if/when state SIP disapproval stays are lifted).

B. Procedural History

The States of Indiana, Ohio, Utah, and West Virginia, along with members of multiple affected industries, timely petitioned for review of the Rule in the D.C. Circuit. *See* D.C. Circuit Lead Case No. 23-1157. The following relevant motions to stay the Rule were then filed:

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of States' roles in achieving air quality standards under the Clean Air Act's cooperative federalism approach, and confirms the extent of EPA's overreach. *See* Order, *Texas v. EPA*, No. 23-60069, ECF 269-1, at 17 ("In sum, because the EPA's lack of deference to the States inverts the agency's 'ministerial function' in this system of 'cooperative federalism,' Stay Petitioners have made a strong showing that the EPA acted unlawfully.") (cleaned up). EPA's overly muscular approach to Clean Air Act regulation, coupled with the immense costs to industry, also implicate the Major Questions Doctrine. *See* Br. for Enbridge (U.S.) Inc. 12–13, No. 23-1157 (D.C. Cir. Aug. 4, 2023) (arguing that EPA's action in universally disapproving state plans in favor of a federal plan "runs roughshod over" cooperative federalism and implicates the Major Questions Doctrine).

[5] One of the Applicants has challenged the First Interim Final Rule in the D.C. Circuit. *See Kinder Morgan v. EPA*, D.C. Cir. No. 23-1279 (Sept. 29, 2023).

- Utah moved to stay on July 7, 2023;[6]
- Indiana, Ohio, and West Virginia moved jointly to stay on July 19, 2023;
- Kinder Morgan moved to stay on July 27, 2023;
- API and INGAA moved to stay on July 27, 2023,
- American Forest & Paper Association, Midwest Ozone Group, America's Power, Associated Electric Cooperative, Inc., Deseret Generation & Transmission Co-Operative, National Rural Electric Cooperative Association, Ohio Valley Electric Corporation, Portland Cement Association, Wabash Valley Power Association, Inc., and the National Mining Association moved to stay on August 2, 2023.
- Enbridge moved to stay on August 4, 2023.
- TC Energy moved to stay on August 8, 2023.

A divided panel of the D.C. Circuit denied the stay motions on September 25, 2023. Order, *Utah v. EPA*, No. 23-1157 (D.C. Cir. Sept. 25, 2023) (266a). Judge Walker dissented. *Id.*

REASONS FOR GRANTING THE APPLICATION

Applicants are entitled to a stay if they can establish that (1) they are likely to succeed on the merits; (2) they will be irreparably injured absent a stay; (3) a stay will not substantially injure other parties; and (4) a stay serves the public interest. *Nken v. Holder*, 556 U.S. 418, 434 (2009). The third and fourth factors merge when the government is the opposing party. *Id.* at 435. These Applicants satisfy each factor.[7]

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[6] Utah subsequently moved to hold the briefing for its motion in abeyance because the Tenth Circuit stayed EPA's disapproval of Utah's state plan; the D.C. Circuit granted Utah's request.

[7] Applicants do not need to meet the standard in *Hollingsworth v. Perry*, 558 U.S. 183, 190 (2010), where the Court analyzes likelihood of granting certiorari and the prospect of reversal. In *Hollingsworth*, this Court considered an application for a stay of a lower court or-

I. APPLICANTS ARE LIKELY TO SUCCEED ON THE MERITS.

A. The Legal Predicate For The Rule Is Undermined By Stays Across Seven Circuits.

As an exercise of cooperative federalism, the Clean Air Act assigns to the States the "primary responsibility for assuring air quality." 42 U.S.C. § 7407(a). As such, EPA only has authority to issue a federal plan if a state plan does not comply with the Act. *See id.* § 7410(c)(1). But seven circuit courts—*all* circuits presented with a request to date—have stayed EPA's disapproval of 12 separate state plans. Thus, a majority of the 20 states where the Rule applies to pipeline engines have now had their state plan disapprovals stayed, eliminating the legal predicate for the Rule in those states. *Id.* § 7410(c)(1)(B).

That state of affairs fundamentally undermines the Rule. EPA itself states that the Rule is based on the "combined effect of the entire program *across all linked upwind states*," 88 Fed. Reg. at 36,749 (emphasis added), so the many judicial stays of the state plan disapprovals have profoundly altered the nature and scope of the multi-state Rule EPA proposed, received comments on, analyzed for emissions impacts, and promulgated. The data tells the story: of EPA's total estimated emissions reductions, only 22 percent remain from the states where EPA continues to have authority to enforce the Rule. Appendix at 649a. By sector, only 11 percent of total EGU emissions reductions remain, and only 40 percent of total non-EGU emissions reductions remain. *Id.*

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der pending the filing of petitions for certiorari and mandamus. *Id.* at 185. Here, by contrast, Applicants seek a stay of a federal rule that the D.C. Circuit's motions panel refused to stay. *See Nat'l Fed'n of Ind. Bus. v. Dep't of Labor*, 142 S.Ct. 661 (2022) (per curiam) (applying traditional *Nken* factors and granting stay in analogous posture). Even if *Hollingsworth* applied, however, *see Does 1–3 v. Mills*, 142 S. Ct. 17, 18 (2021) (Barrett, J., concurring) (understanding *Nken*'s first factor to encompass the *Hollingsworth* standard), Applicants would still satisfy that standard given the importance of the issues and the Rule's significant legal flaws.

Given this data, EPA's own rationale for the Rule disintegrates. EPA itself emphasized that the Rule is meant to address interstate ozone transport "on a national scale" and that "consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is 'efficient and equitable.'" 88 Fed. Reg. at 36,691 (quoting *EME Homer*, 572 U.S. at 519). Now, the Rule no longer applies on a "national scale" and imposes inconsistent requirements among states. Similarly, EPA stated that the Rule depends on "a uniform level of emissions reduction . . . the linked upwind states can achieve," *id.* at 36,676, but the Rule is not "uniform" when it applies to less than half the states EPA originally intended.

On top of that, the Rule's ozone-reduction rationale no longer applies. EPA concluded that "the *collective* application of these mitigation measures and emissions reductions are projected to deliver meaningful downwind air quality improvements" of 0.66 parts per billion (ppb) of ozone reduction on average. *Id.* at 36,748 (emphasis added). In proposing and promulgating the Rule, EPA also emphasized that an individual state's contribution may be relatively small, but the "*collective* contribution resulting from multiple upwind states" may not. *Id.* at 36,678 (emphasis added). With 78 percent of the "collective" emission reductions now stayed, it is unclear what, if any, ozone benefit would result; EPA did not analyze the effect of a *partial* rule.

EPA may respond that it considers the Rule severable. *See id.* at 36,693 ("[S]hould a court find any discrete aspect of this document invalid, the Agency believes that the remaining aspects of this rule can and should be implemented to the extent possible."). But severability depends on whether the provisions at issue are actually severable, *Reno v. ACLU*, 521 U.S. 844, 882–83 (1997), meaning whether "the remainder of the regulation could function sensibly without the stricken provision." *MD/DC/DE Broadcasters Ass'n v. FCC*, 236 F.3d 13, 22 (D.C. Cir.), *aff'd on reh'g*, 253 F.3d 732, 734 (D.C. Cir. 2001) (en banc); *see also Minnesota v. Mille Lacs Band of Chippewa Indians*, 526 U.S. 172, 194 (1999) (entirety of order inseverable, "embodying as it did one coherent policy"). Where severance would "severely distort the [agency's] program and produce a rule strikingly different from any the [agency] has ever considered or promulgated," as here, the regulation cannot be severed. *MD/DC/DE Broadcasters*, 236 F.3d at 23. EPA's own statements in briefing on venue drive this home: "[The Rule] depends on the continuing operation of 'interdependent' interstate mechanisms." *Tulsa Cement et al. v. EPA*, EPA's Motion to Dismiss or Transfer Petitions for Improper Venue 16, No. 23-9551 (10th Cir. July 20, 2023). With these interdependencies dissolved by the stays spanning 12 states, and with the Rule's striking difference from the one considered and promulgated, the whole Rule falls apart.

This procedural and substantive mess is compounded by the foundational legal issues with the Rule itself, which we discuss in turn.

B. EPA Failed To Identify Emissions "Amounts" From Non-EGU Sources That Contribute Significantly to Nonattainment, Failed to Explain its Departure From Past Practice, and Failed to Justify its Conclusions.

In its proposed rule, and applying its "uniform cost" framework upheld by *EME Homer*, 88 Fed. Reg. at 36,719, EPA used a "marginal cost threshold of $7,500 per ton" of emissions as the threshold for the "amounts" of emissions to be eliminated for non-EGU sources, including pipeline engines, 87 Fed. Reg. at 20,083. After pipeline companies identified critical flaws in EPA's cost data and analysis during the comment period (including that the Rule would apply to more than three times the number of engines that EPA assumed), EPA jettisoned that threshold as "not reflect[ing] the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed." 88 Fed. Reg. at 36,740, 36,746.

But EPA then made a critical error: it never adopted (or even analyzed) a revised cost threshold reflecting the "amount of emissions that is in excess of the emissions control strategies that EPA has deemed cost-effective." 88 Fed. Reg. at 36,676. Instead, it continued to require the same emissions controls identified at the proposal stage that *were not* reflective of the full range of cost-effectiveness values pipeline engines would face. EPA's flawed Rule thus requires emissions reductions on engines that vastly exceed $7,500 per ton. *See* TC Energy Comment 5 (noting total costs of Rule of $900 million for engines that operate infrequently) (603a); Kinder Morgan Comment 21–26 (noting costs above $100,000/ton and even above $684,169/ton) (543a–548a). EPA's approach runs afoul of the Clean Air Act—and this Court's prior precedent—and arbitrarily and capriciously departs from its own past practice.

First, the Clean Air Act requires EPA to define the "amounts" of pollutants to be reduced. 42 U.S.C. § 7410(a)(2)(D)(i)(I). As the D.C. Circuit has explained, "[i]nterstate contributions cannot be assumed out of thin air." *Michigan v. EPA*, 213 F.3d 663, 684 (2000). Rather, they must be grounded in an "amount." EPA definitively decided to define this amount in this Rule using a cost-effectiveness criterion, where "upwind emissions rank as 'amounts [that] . . . contribute significantly to nonattainment' if they . . . can be eliminated under the cost threshold set by the Agency." *EME Homer*, 572 U.S. at 518; 88 Fed. Reg. at 36,719. EPA maintains that the Rule "continues to apply the same approach as the prior three [interstate transport] rulemakings" for evaluating "amounts" of "significant contribution," which are "represented by cost thresholds." 88 Fed. Reg. at 36,678; *see Maryland v. EPA*, 958 F.3d 1185, 1192 (D.C. Cir. 2020). EPA is wrong. In discarding its proposed cost-effectiveness threshold in the final Rule without ever defining an alternative, EPA failed to determine the statutory "amounts" of emissions required to be eliminated.[8]

Second, EPA's failure to define "amounts" as "represented by a cost threshold" also departs from its own long-held approach. In past ozone transport rules, EPA required industries to install only those control technologies that are cost-effective, based on a defined threshold. *See, e.g.*, 76 Fed. Reg. 48,208, 48,248 (Aug. 8, 2011) ("defin[ing] each state's . . . contribution . . . as the emission reductions available *at a particular cost threshold* in a specific upwind state." (emphasis added)). And when EPA found a cost threshold unrepresentative, it did not require reductions. *See, e.g.*, 70 Fed. Reg. 25,162, 25,214 (May 12, 2005) ("EPA believes it is necessary to have . . . better control cost information for [non-EGUs] before assuming reductions from them."); 81 Fed. Reg. 74,504, 74,508 (Oct. 26, 2016) ("Our analysis shows that there is uncertainty regarding whether or not meaningful, cost-effective non-EGU emission reductions are achievable . . . . Therefore, non-EGU reductions are not included in the final rule.").

Despite admitting that the $7,500 threshold did "not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed," EPA is still forcing companies to install those same controls it proposed. 88 Fed. Reg. at 36,746. EPA also did *not explain* why it was departing from

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[8] EPA may argue in response that the $7,500 threshold was never supposed to be a fixed cost threshold above which emissions reductions would not be required. But the agency's own record belies that claim. EPA said at proposal that it "believes that . . . engines subject to this proposed [rule] can achieve the emissions limit of 1.5 g/hp-hr with the installation and operation" of specified "control technologies *at the marginal cost threshold of $7,500 per ton*." 87 Fed. Reg. at 20,142–43 (emphasis added).

its past practice in defining a cost-effectiveness threshold above which emissions reductions are not required. *See FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515–16 (2009) (reasoned explanation required when agency departs from past practice). Even worse, EPA changed its interpretation in a final rule, without the opportunity for notice and comment. *See Shell Oil Co. v. EPA*, 950 F.2d 741, 747 (D.C. Cir. 1991). Indeed, one commenter noted that "[i]t is unclear how EPA could make the necessary findings for a final rule given the inaccurate data it relies upon." Kinder Morgan Comment 3 (525a). EPA's failure to provide a reasoned explanation "for disregarding facts and circumstances that underlay or were engendered by the prior policy" was arbitrary and capricious. *Encino Motorcars, LLC v. Navarro*, 579 U.S. 211, 222 (2016) (quoting *Fox Television*, 556 U.S. at 515–16).

For the Clean Air Act's requirements to have any meaning, EPA cannot be allowed to choose to define a source's "significant contribution" in terms of whether the source can make cost-effective emissions reductions, identify a threshold for assessing cost-effectiveness, and then deem cost-effectiveness irrelevant by finalizing a Rule that imposes costs vastly exceeding the threshold. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must "articulate a satisfactory explanation for its action," including "a rational connection between the facts found and the choice made.").

EPA likely will respond that the Rule provides a limited exemption process for "certain individual facilities and emissions units [that] may face extreme hardship," 88 Fed. Reg. at 36,747 n.250. But that process is no panacea. First, whether to grant an exemption is committed to EPA's sole discretion. *See* 40 C.F.R. §52.40(e)(2)(B) (demonstration of extreme economic hardship must be to EPA's "satisfaction"). Thus, pipeline companies have no assurance that even an engine with emission-reduction costs far in excess of $7,500/ton would be granted an exemption. Second, to be granted this discretionary cost-based exemption, companies must demonstrate "*extreme* economic hardship"—a standard EPA has never used and has yet to define as a fixed cost-per-ton threshold. *Id*. (emphasis added). And third, by limiting exemptions to "individual facilities and emissions units" on a case-by-case basis, it is unlikely that EPA will grant widespread exemptions even though widespread exemptions will inevitably be necessary.[9] The theoretical availability of occasional exemptions does not save this deeply flawed Rule. *See Ass'n of Oil Pipe Lines v. FERC*, 281 F.3d 239, 244 (D.C. Cir. 2002) ("safety valve" could not "rescue [agency's rule] from systemic errors, for then the exception would swallow the rule").

C. EPA's Compliance Timeline Failed To Consider Natural Gas Reliability Impacts.

The Rule requires the pipeline transportation sector to implement complex control technologies by May 1, 2026—an impossible deadline for pipeline engines. 88 Fed. Reg. at 36,756.[10] These emissions requirements apply to over *three thousand* pipeline engines across the country, *id.* at 36,824, but a retrofit on a *single* engine "requires between 1 and 2 ½ years to complete (from inception to completion of commissioning)," INGAA Comment 36

[9] There are only two vendors nationwide with the necessary equipment and experience to retrofit most pipeline engines, and those contractors have never processed the scale and magnitude of requests that the Rule forces. *See* Kinder Morgan Comment 28 (550a); *NOx Emissions Control Technology Installation Report Timing for Non-EGU Sources, Final Report*, EPA-HQ-OAR-2021-0668-1077, 68, A-1–A-3 (Mar. 14, 2023) (Timing Report) (454a, 456a–458a). EPA ignored these logistical impediments as well.

[10] EPA contends that "the publication of the proposal" also "provided roughly an additional year of notice." *Id.* That contention is meritless. *See Window Covering Mfrs. Ass'n v. Consumer Prod. Safety Comm'n*, No. 22-1300, 2023 WL 5918899, at *13 (D.C. Cir. Sept. 12, 2023) (rejecting agency's assertion that the proposed rule gave additional notice to the regulated industry in concluding agency's chosen effective date was arbitrary and capricious).

(500a).[11] EPA's refusal to provide a feasible compliance deadline jeopardizes the safe and reliable transportation of natural gas in the United States. *See id.* at 34–42 (explaining impossibility of EPA's proposed compliance date for pipeline engines and noting that EPA had not evaluated pipeline reliability impacts of its proposed compliance date) (498a–506a); *Memphis Light, Gas & Water Div. v. Craft*, 436 U.S. 1, 18 (1978) (recognizing "utility service" as a "necessity of modern life"). Notwithstanding the gravity of this concern, EPA failed to consider the adverse impacts to natural gas reliability when setting the compliance deadline, which will result in natural gas and electric power service interruptions during the times of year when downstream users, including homes, businesses, institutions (such as schools and hospitals), and electric power plants, need fuel the most.

With over three thousand regulated engines, basic math dictates that pipeline companies will need to take numerous pipeline engines offline simultaneously (for months each, once the operator secures the permits, contractor, and parts) to even attempt to meet the 2026 deadline. These outages will in turn cause a "large-scale reduction in output of natural gas," Kinder Morgan Comment 29, 36–37 (551a, 558a–559a), and "prevent[] [natural gas] shippers from transporting as much gas as their users require," INGAA Comment 42 (506a). Despite the importance of natural gas reliability and industry comments, EPA offers scant discussion on—and no meaningful support for—its conclusion that the Rule would not cause supply shortages.

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11 This is in part because pipeline engines are a far cry from the small engines in cars and trucks. Pipeline engines typically weigh at least 100,000 pounds and can weigh as much as 365,000 pounds, and they are highly complex and integrated machines. Kinder Morgan Comment 28 (550a).

First, EPA relies on a cursory report it commissioned, and which it did not publish until the final Rule, which suggests that operators could simply "coordinate outages" of pipeline engines to minimize natural gas reliability concerns and service disruptions. EPA, *NOx Emissions Control Technology Installation Report Timing for Non-EGU Sources, Final Report*, EPA-HQ-OAR-2021-0668-1077, ES-8 (Mar. 14, 2023) (Timing Report) (385a). That rationale is both misplaced and unsupported. Pipelines are linear. Pipeline engines are spread every 40 to 100 miles along the pipeline network to ensure sufficient flow of natural gas. If one engine is taken offline for retrofits, there is limited ability for an engine immediately ahead or behind it to substitute for its capacity at high demand, and there is no ability to substitute engine capacity across different pipelines. Further, even if such coordination were physically possible, EPA does not consider that pipeline capacity cannot be coordinated among different pipeline operators, given that pipeline companies are competitors—meaning agreements between them to allocate capacity would trigger serious antitrust concerns.[12] And each pipeline operator can have unique delivery points to distribution companies, gas-fired electric generators, or industrial customers that no other operator can access, eliminating any opportunity for coordination. EPA's proposed solution is thus no solution at all.

Second, the Timing Report expressly states that its authors "were not able to complete an evaluation of" the reliability concerns raised during the comment period. Timing Report at ES-8 (385a). Given that the Timing Report represents EPA's only analysis of pipeline reliability concerns at all, EPA admits that it "failed to consider [this] important aspect of the

[12] *See In re Musical Instruments & Equip. Antitrust Litig.*, 798 F.3d 1186, 1191 (9th Cir. 2015) ("[A]greements among competitors to fix prices, divide markets, and refuse to deal . . . [are] inherently anticompetitive horizontal agreements [that] violate the Sherman Act per se.").

problem." *State Farm*, 463 U.S. at 43. EPA's lack of consideration for natural gas reliability is especially stark in contrast with the lengthy electric-sector reliability evaluation (where the agency at least paid lip service to the issue for EGUs), particularly where gas-fired power plants themselves rely on pipelines for fuel. *See* 88 Fed. Reg. at 36,772 n.301 (noting report EPA prepared to evaluate electric-sector reliability).

EPA's failure to consider these adverse impacts drew ire from a Federal Energy Regulatory Commissioner, who observed with respect to the Rule that "[a]lthough EPA responds to arguments regarding how the EGU portion of its rule affects electric reliability, . . . EPA [did] not ever consider the impacts that the timeline for compliance for non-EGUs would have on electric reliability or residential uses." Commissioner James Danly, *Response to Questions for the Record for June 13, 2023 House Energy & Commerce Oversight Hearing* 23–24, https://perma.cc/C757-3DD3 (637a–638a). Quite so.

The Rule's unrealistic compliance timeline cannot be saved by the fact that the Rule allows an operator to request a case-by-case extension in exceptional circumstances. Indeed, for the reasons discussed above, extensions will almost certainly be required across the board, rather than only in one-off or exceptional cases.

EPA thus "entirely failed to consider an important aspect of the problem" when adopting the compliance timeline—namely, the widespread impacts to natural gas reliability—and the Rule is arbitrary and capricious as a result. *State Farm*, 463 U.S. at 43; *see Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 544–545, 552 (D.C. Cir. 1983) (vacating EPA's gasoline lead standard under the Clean Air Act in part for lack of record evidence that compliance timeline was achievable).

D. EPA's 1,000-Horsepower Applicability Criterion For Pipeline Engines Is Unlawful.

EPA also erred by adopting an initial applicability criterion that captures many pipeline engines whose emissions are far *below* the threshold EPA used to screen out sources that do not "contribute significantly."

In determining which sources to regulate, and before applying the marginal cost threshold discussed above, EPA "focused on assessing emission units that emit > 100 [tons per year] of NOx." EPA, *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* at 3 (Feb. 28, 2022) (736a). EPA's decision to screen out sources that emit less than that amount necessarily represents a determination that those sources do not "significantly contribute" to downwind nonattainment. *Maryland*, 958 F.3d at 1204.

For some other non-EGU sources, EPA used 100 tons per year of actual emissions as a threshold for the applicability criterion. *See* 88 Fed. Reg. at 36,825 (cement and concrete product manufacturing); *id.* at 36,827 (iron and steel mills and ferroalloy manufacturing); *id.* at 36,829 (glass and glass product manufacturing). For pipeline engines, by contrast, EPA did not. Instead, it implemented the 100-tons-per-year threshold by using a horsepower-based proxy, lumping in all pipeline engines with a design capacity of 1,000 horsepower or greater and asserting that this criterion "reasonably approximates" the 100-tons-per-year threshold. 88 Fed. Reg. at 36,820; *see also* 87 Fed. Reg. 20,036, 20,142 (proposed Apr. 6, 2022).

At the proposal stage, EPA projected that its horsepower proxy would cover only 307 engines nationwide. 87 Fed. Reg. at 20,090. And it projected that a significant majority of those engines would exceed the 100-tons-per-year threshold: EPA estimated that "over 200 engines" out of 307 "emitted greater than 100 [tons per year]." EPA, *Technical Support Document (TSD) for the Final Rule: Final Non-EGU Sectors TSD* at 4 (Mar. 2023) (271a).

Commenters demonstrated that EPA had wildly underestimated the proposed rule's reach. *See* INGAA Comment 8–9 (472a–473a (stating that INGAA's members alone operate 1,380 units that would be regulated, contrasting with EPA's estimate of 307 engines in total). In the Final Rule, EPA admitted that the 1,000-horsepower criterion had "captured more units than the EPA intended," including "low-use units and some units with emissions of less than 100 tons per year." 88 Fed. Reg. at 36,819, 36,821. That was an understatement: EPA now projects that 3,005 units are subject to the Rule—almost *ten times* its initial projection. *Id.* at 36,824. Yet EPA continued to project that fewer than 300 units would meet the 100-tons-per-year threshold for coverage under the Rule. *See* EPA, *Non-EGU Facilities and Units.xlsx* (Mar. 2023) (listing about 260 engines above the threshold), https://perma.cc/UDK9-LRKU (downloads file).

EPA nonetheless persisted in its plan to regulate all units with a 1,000-horsepower rating, refusing to adjust its applicability criterion to address the mismatch of actual emissions as compared to potential emissions. 88 Fed. Reg. at 36,819–21. This was unlawful.

First, EPA's applicability criterion results in regulation of a significant number of engines that, by EPA's own logic, do not "contribute significantly." That exceeds EPA's authority under the statute: EPA may not require emissions reductions "at odds with the . . . threshold the Agency has set." *EME Homer*, 572 U.S. at 521.

Second, EPA's finding that a 1,000-horsepower rating "reasonably approximates" the 100-tons-per-year threshold, 88 Fed. Reg. at 36,820, "runs counter to the evidence before the agency," *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43. EPA's own data shows that fewer than one in ten of the units subject to the rule meet the 100-tons-per-year threshold. The rest are collateral damage. A "reasonable approximation" is one that fairly, if inexactly, captures the target group. *Cf. Worldcom, Inc. v. FCC*, 238 F.3d 449, 459 (D.C. Cir. 2001). Rather than a "reasonable approximation," the Rule amounts to a tenfold expansion of EPA's regulatory reach beyond sources that "contribute significantly."

Third, EPA's reasons for declining to adjust the applicability criterion are arbitrary and capricious. *Balt. Gas & Elec. Co. v. FERC*, 954 F.3d 279, 285 (D.C. Cir. 2020) (agency has a "duty to explain inconsistent treatment" of regulated entities). EPA tried to justify its overreach by claiming that the hundreds of units below the emissions threshold could one day exceed 100 tons per year and it is "not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future." 88 Fed. Reg. at 36,821. But the statute applies only to sources that "*will* . . . contribute significantly," 42 U.S.C. § 7410(a)(2)(D)(i) (emphasis added), not that "could potentially" do so in the future. And, contrary to EPA's assertion, it is possible to ensure that units do not increase their emissions: As it did in the Rule for other sources, EPA could impose a reporting obligation and require compliance with emissions limits if the 100-tons-per-year threshold is exceeded. *Cf*. 40 C.F.R. § 52.45(b)(1)–(2) (exempting low-use boilers from all but recordkeeping and reporting requirements unless they exceed certain usage thresholds).

II. ABSENT A STAY, PIPELINE OPERATORS—AND THEIR CUSTOMERS—WILL BE IRREPARABLY HARMED.

Absent a stay, pipeline operators will be forced to curtail natural gas shipments—causing supply interruptions—while they take pipeline engines offline for retrofits to meet EPA's infeasible and unsupported compliance timeline and spend hundreds of millions of dollars in just the 12 to 18 months after the Rule's effective date (August 4, 2023) on those retrofits. Interrupted natural gas supplies no doubt constitute irreparable injury—to the public and pipeline companies. Likewise, compliance costs that cannot be recovered are irreparable. *Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220–21 (1994) (Scalia, J., concurring in part and concurring in the judgment) ("[C]omplying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs."); *see also Ala. Ass'n of Realtors v. HHS*, 141 S. Ct. 2485, 2489 (2021) (per curiam) (noting financial impact "with no guarantee of eventual recovery" put applicants "at risk of irreparable injury").

Natural gas reliability. Natural gas pipelines—the backbone of the country's natural gas supply infrastructure—cannot retrofit all their engines in time to meet EPA's compliance deadline of May 1, 2026. *Supra* at 17–21. To even have a chance of meeting that deadline, pipeline operators will need to take engines offline during peak-demand seasons (winter and summer) to retrofit all the engines required.[13]

Pipeline engines are large, complex pieces of machinery, and *a single* retrofit project can take from one to two-and-a-half years from engineering development to commissioning. Yeager Decl. ¶ 19 (716a). The installation phase itself can take between three to six months per engine or six to 12 months per compressor station. Wooden Decl. ¶ 11 (702a). Before construction can even begin, pipeline operators need to have state permits in hand, and the permit process itself can take over a year, even without delays. Grubb Decl. ¶ 52 (681a).

[13] Pipeline operators must do so to achieve the emissions limits in states where the Rule is not stayed, and as noted above, EPA offered only vague assurances that compliance timelines would be pushed back to account for existing state plan disapproval stays. *See* 88 Fed. Reg. at 67,103–04 (EPA "generally anticipates" that lead times would be "comparable" if/when state plan disapproval stays are lifted).

Adding this all together, pipeline operators will have a short window of time to retrofit engines, and these retrofits would require taking hundreds of engines offline during peak-demand seasons, risking natural gas reliability for winter heating (November to March) and for use in power plants to serve air conditioning loads in the summer (May to September). Grubb Decl. ¶¶ 61–69 (685a–693a); Wooden Decl. ¶¶ 11–12 (702a–703a). This forced-march timeline sharply contrasts with pipeline operators' practice of scheduling service or other necessary outages during *lower* demand periods. Grubb Decl. ¶ 62 (685a–686a).

Two case studies illustrate that reliability concerns are concrete and imminent. Kinder Morgan performed computer simulation modeling on two of its pipelines to evaluate the pipeline capacity impacts that will result if Kinder Morgan attempts to meet the May 1, 2026, compliance date for as many of its engines as possible. Grubb Decl. ¶¶ 64–66 (687a–689a). First, for its pipeline system serving the Chicago area—which serves approximately 60 percent of the Chicago natural gas market—Kinder Morgan found that its delivery capacity during peak-demand winter days in Chicago would fall 20 percent short of demand. *Id.* ¶ 66 (689a). That shortfall equates to approximately 1,761,000 homes' worth of natural gas usage that could not be supplied during a peak-demand winter day. *Id.* (689a). Second, the same modeling showed that Kinder Morgan's pipeline segment serving the Gulf Coast region would experience shortfalls of delivered natural gas equating to hundreds of thousands of homes going unserved during both summer and winter periods. *Id.* ¶ 67 (690a–691a). Kinder Morgan's natural gas system in this region also serves six natural gas-fired power plants, which collectively provide electricity to millions of customers. *Id.* (690a–691a).

EPA will likely argue that pipelines have sufficient spare capacity to absorb required engine outages, given pipelines' "average annual capacity utilization." *See* Timing Report at

ES-8, 8 (385a, 394a) (citing average annual capacity utilization of 40 percent). This is not a solution; indeed, it only reveals EPA's deep misunderstanding of the pipeline industry. *Average* capacity utilization bears little on the ability to serve *peak* demand. Natural gas demand is highly seasonal; pipelines experience much higher demand when weather is extremely hot or extremely cold, and demand ebbs in the spring and fall. For a particular pipeline, then, "40 percent utilization" could mean a much lower percent utilization during low-demand times in spring and fall and over 95 percent during peak summer and winter demand. And if the weather turns hot or cold in these "off-peak" months, utilization jumps higher.

Relying on a 40% average capacity utilization also presupposes that engine capacity can be borrowed across the entire industry. The capacity a pipeline engine provides is highly location- and pipeline-specific. Even within a single pipeline, there is little ability for sharing the work of engines too far upstream or downstream in the pipeline. And in certain highly populated regions, there is only one pipeline company that can deliver to core urban areas, making sharing among different pipeline companies a physical impossibility.

The Rule's purported compliance flexibilities will not avoid irreparable injury either. First, EPA estimates that only one-third of engines would require controls because of its allowance for facility-wide emissions averaging. 88 Fed. Reg. at 36,760. But EPA's analysis of this supposed option is based on unrepresentative and extremely limited data and provides operators little practical ability to reduce the number of engines requiring retrofits. Grubb Decl. ¶¶ 35–44 (670a–676a) (noting that EPA only evaluated 10 compressor stations (out of 713 total), all of which have far more engines than the average compressor station, and therefore show more benefit from averaging than would be experienced in practice).[14] Second, and as discussed above (at 16–17), the case-by-case emissions limit for *extreme* economic hardship is only meant to apply on a limited basis, and EPA has not provided a specific cost threshold that would qualify, making it impossible for companies to reasonably rely on this option. Yager Decl. ¶ 9 (711a). Third, the compliance timeline extensions would be required for a massive number of pipeline engines. For example, Kinder Morgan alone has concluded it would need an extension for approximately half of its engines that do not currently meet the emissions limits. Grubb Decl. ¶ 48 (679a). And to qualify, operators must "take[] *all steps possible* to install controls for compliance with the applicable requirements," 40 C.F.R. § 52.40(d)(3), meaning they need to begin performing engine retrofits promptly and through the pendency of litigation. Finally, EPA has sole discretion to grant any of these compliance flexibilities; operators cannot reasonably rely on EPA to do so.

Compliance costs. Individual pipeline companies face steep compliance costs in the 12 to 18 months after the Rule's effective date. As of July 2023, Enbridge expected to incur $350 million;[15] Kinder Morgan expected to incur $270 million;[16] and TC Energy expected to incur $75 million.[17] Adding these costs plus its other members' costs, INGAA estimated that its members will need to spend at least *several hundred million dollars* on engine retrofits

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[14] The averaging approach also offers little flexibility in practice because it presents a constantly moving target based on a "rolling" lookback period. Grubb Decl. ¶ 44 (676a).

[15] Wooden Decl. ¶ 13 (703a).

[16] Grubb Decl. ¶¶ 6, 28 (653a–654a, 666a–667a).

[17] Yeager Decl. ¶ 9 (722a).

over the same period. Yager Decl. ¶ 10 (712a). Absent a stay, if a court later invalidates the Rule, pipeline companies will not be able to recover these substantial costs.

The total costs expected for retrofits of engines to meet the Rule's emissions rates limits are even more jaw-dropping. As of July 2023, Kinder Morgan anticipated $1.8 to $2.1 billion;[18] Enbridge anticipated $1 billion;[19] and TC Energy anticipated $600 million.[20] In total, INGAA estimated that its members will have to spend up to approximately *six billion dollars.* Yager Decl. ¶ 10 (712a). And even these astronomical amounts do not include costs resulting from curtailed shipments and other opportunity costs. Grubb Decl. ¶¶ 45–46, 70–73 (676a–679a, 693a–695a) (noting costs of modernizations and emissions reduction projects placed on hold, as well as "reservation charge credits"—i.e., refunds—to customers for interrupted pipeline service); Wooden Decl. ¶ 14 (703a) (system modernization plans being deferred). These burdensome costs constitute the types of irreparable injury other circuit courts have necessarily found when issuing stays of EPA's state plan disapprovals. *See, e.g.*, Order at 23, *Texas v. EPA*, No. 23-60069, ECF 269-1 ("Stay Petitioners will be forced to spend billions of dollars in compliance costs . . . .").

To avert natural gas delivery interruptions during peak seasons and to prevent pipeline companies from facing exorbitant compliance costs, this Court should stay the Rule.

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18 Grubb Decl. ¶¶ 6, 26 (653a, 666a).

19 Wooden Decl. ¶ 14 (703a).

20 Yeager Decl. ¶¶ 9, 15 (722a, 724a).

III. THE BALANCE OF HARMS AND THE PUBLIC INTEREST WEIGH HEAVILY IN FAVOR OF A STAY.

Even where a compelling public interest exists, "our system does not permit agencies to act unlawfully even in pursuit of desirable ends." *Ala. Ass'n of Realtors*, 141 S. Ct. at 2490. Accordingly, "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations.'" *League of Women Voters of United States v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (citation omitted). Here, given EPA's unlawful actions, the public interest strongly supports a stay.

A stay is also warranted because EPA, and only EPA, is responsible for the Rule's constrained timeline, given the immense gap between States' 2018 plan submissions and EPA's 2023 disapprovals. As the Fifth Circuit observed, "EPA's multi-year delay" in disapproving states' implementation plans "undercuts any claim that time is of the essence when it comes to imposing" the Rule. Order at 24, *Texas v. EPA*, 5th Cir. No. 23-60069, ECF 269-1. Where EPA set an unreasonable compliance deadline for pipeline engines, and where EPA was the source of the delay in the first instance, EPA cannot argue that it or the public is harmed by a stay. On the contrary, the public interest in ensuring the consistent and reliable supply of natural gas to downstream consumers, including homes, businesses, and electric power plants, tips sharply in favor of a stay.

CONCLUSION

For the foregoing reasons, Applicants respectfully request an immediate stay of the Rule's provisions for pipeline engines.

Respectfully submitted,

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APPENDIX

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78, and 97

[EPA–HQ–OAR–2021–0668; FRL–8670–02–OAR]

RIN 2060–AV51

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes Federal Implementation Plan (FIP) requirements to address 23 states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is taking this action under the ''good neighbor'' or ''interstate transport'' provision of the Clean Air Act (CAA or Act). The Agency is defining the amount of ozone-precursor emissions (specifically, nitrogen oxides) that constitute significant contribution to nonattainment and interference with maintenance from these 23 states. With respect to fossil fuel-fired power plants in 22 states, this action will prohibit those emissions by implementing an allowance-based trading program beginning in the 2023 ozone season. With respect to certain other industrial stationary sources in 20 states, this action will prohibit those emissions through emissions limitations and associated requirements beginning in the 2026 ozone season. These industrial source types are: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

DATES: This final rule is effective on August 4, 2023.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021–0668. All documents in the docket are listed in the *https://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at *https://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA Docket Center, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket is (202) 566–1742.

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: (312) 886–4746; 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
ABC Associated Builders and Contractors
ACS American Community Survey
ACT Alternative Control Techniques
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQS Air Quality System
BACT Best Available Control Technology
BART Best Available Retrofit Technology
BOF Basic Oxygen Furnace
BPT Benefit Per Ton
C1C2 Category 1 and Category 2
C3 Category 3
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
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CFB Circulating Fluidized Bed Units
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CRA Congressional Review Act
CSAPR Cross-State Air Pollution Rule
DAHS Data Acquisition and Handling System
DOE Department of Energy
EAF Electric Arc Furnace
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EIS Emissions Inventory System
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
ERT Electronic Reporting Tool
FERC Federal Energy Regulatory Commission
FFS Findings of Failure to Submit
FIP Federal Implementation Plan
GIS Geographic Information System
g/hp-hr grams per horsepower per hour
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
IRA Inflation Reduction Act
LAER Lowest Achievable Emission Rate
LDC Local Distribution Company
LME Low Mass Emissions
LNB Low-NO_X Burners
MATS Mercury and Air Toxics Standards
MCM Menu of Control Measures
MDA8 Maximum Daily Average 8-Hour
MJO Multi-Jurisdictional Organization
MOU Memorandum of Understanding
MOVES Motor Vehicle Emissions Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NERC North American Electric Reliability Corporation
NESHAP National Emissions Standards for Hazardous Air Pollutants
NMB Normalized Mean Bias
NME Normalized Mean Error
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NODA Notice of Data Availability
NO_X Nitrogen Oxides
NREL National Renewable Energy Lab
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standard
NSR New Source Review
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
PDF Portable Document Format
PEMS Predictive Emissions Monitoring Systems
$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmv parts per million by volume
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PTE Potential to Emit
RACT Reasonably Available Control Technology
RATA Relative Accuracy Test Audit
RCF Relative Contribution Factor
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
RTC Response to Comments
RTO Regional Transmission Organization
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCC Source Classification Code
SCR Selective Catalytic Reduction
SIL Significant Impact Level
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TAS Treatment as State
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 final rule resolves the interstate transport obligations of 23 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 submit to EPA ozone infrastructure State Implementation Plan (SIP) revisions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018. The EPA proposed the subject rule to address outstanding interstate ozone transport obligations for the 2015 ozone NAAQS in the **Federal Register** on April 6, 2022 (87 FR 20036).

The EPA is making a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in downwind states, based on projected ozone precursor emissions in the 2023 ozone season. The EPA is issuing FIP requirements to eliminate interstate transport of ozone precursor emissions from these 23 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in downwind states. The EPA is not finalizing its proposed error correction for Delaware's ozone transport SIP, and we are deferring final action at this time on the proposed FIPs for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action. As discussed in section III of this document, the EPA's updated analysis of 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico may be significantly contributing to one or more nonattainment or maintenance receptors. The EPA is not making any final determinations with respect to these states in this action but intends to address these states, along with Tennessee and Wyoming, in a subsequent action or actions.

The EPA is finalizing FIP requirements for 21 states for which the Agency has, in a separate action, disapproved (or partially disapproved) ozone transport SIP revisions that were 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, Texas, Utah, West Virginia, and Wisconsin. *See* 88 FR 9336. In this final rule, the EPA is issuing FIPs for two states—Pennsylvania and Virginia—for which the EPA issued Findings of Failure to Submit for 2015 ozone NAAQS transport SIPs. *See* 84 FR 66612 (December 5, 2019). Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final 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]

This final rule defines ozone season nitrogen oxides (NO_X) emissions

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

[2] In general, specific tribal names or reservations are not identified separately in this final rule except as needed. *See* section III.C.2 of this document for further discussion about the application of this rule in Indian Country.

performance obligations for Electric Generating Unit (EGU) sources and fulfills those obligations by implementing an allowance-based ozone season trading program beginning in 2023. This rule also establishes emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as ''non-Electric Generating Units'' (non-EGUs)). Taken together, these regulatory requirements will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone NAAQS.

This final rule implements the necessary emissions reductions as follows. Under the FIP requirements, EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) are required 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] In addition to reflecting emissions reductions based on the Agency's determination of the necessary control stringency in this rule, the revised trading program includes several enhancements to the program's design to better ensure achievement of the selected control stringency on all days of the ozone season and over time. For 12 states already required to participate 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) under the Revised CSAPR Update (with respect to the 2008 ozone NAAQS), the FIPs are amended by the revisions to the Group 3 trading program regulations. For seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, 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. The EPA is issuing new FIPs for three states not currently covered by any CSAPR NO_X ozone season trading program: Minnesota, Nevada, and Utah.

This rulemaking requires emissions reductions in the selected control stringency to be achieved as expeditiously as practicable and, to the extent possible, by the next applicable nonattainment dates for downwind areas for the 2015 ozone NAAQS. Thus, initial emissions reductions from EGUs will be required beginning in the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.

The remaining emissions reduction obligations will be phased in as soon as possible thereafter. Substantial additional reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs, also referred to in this action as industrial sources, will phase in beginning in the 2026 ozone season, associated with the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. The EPA had proposed to require all emissions reductions to eliminate significant contribution to be in place by the 2026 ozone season. While we continue to view 2026 as the appropriate analytic year for purposes of applying the 4-step interstate transport framework, as discussed in section V.D.4 and VI.A.2 of this document, the final rule will allow individual facilities limited additional time to fully implement the required emissions reductions where the owner or operator demonstrates to the EPA's satisfaction that more rapid compliance is not possible. For EGUs, the emissions trading program budget stringency associated with retrofit of post-combustion controls will be phased in over two ozone seasons (2026–2027). For industrial sources, this final rule provides a process for individual facilities to seek a one year extension, with the possibility of up to two additional years, based on a specific showing of necessity.

The EGU emissions reductions are based on the feasibility of control installation for EGUs in 19 states that remain linked to downwind nonattainment and maintenance receptors in 2026. These 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The emissions reductions required for EGUs in these states are based primarily on the potential retrofit of additional post-combustion controls for NO_X on most coal-fired EGUs and a portion of oil/gas-fired EGUs that are currently lacking such controls.

The EPA is finalizing, with some modifications from proposal in response to comments, certain additional features in the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets and recalibration of the allowance bank over time as well as backstop daily emissions rate limits for large coal-fired units. The purpose of these enhancements is to better ensure that the emissions control stringency the EPA found necessary to eliminate significant contribution at Step 3 of the 4-step interstate transport framework is maintained over time in Step 4 implementation and is durable to changes in the power sector. These enhancements ensure the elimination of significant contribution is maintained both in terms of geographical distribution (by limiting the degree to which individual sources can avoid making emissions reductions) and in terms of temporal distribution (by better ensuring emissions reductions are maintained throughout each ozone season, year over year). As we further discuss in section V.D of this document, these changes do not alter the stringency of the emissions trading program over time. Rather, they ensure that the trading program (as the method of implementation at Step 4) remains aligned with the determinations made at Step 3. These enhancements are further discussed in section VI.B of this document.

The EPA is making a finding that NO_X emissions from certain 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 is establishing emissions limitations beginning in 2026 for non-EGU sources located within 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The final rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in

[3] As explained in section V.C.1 of this document, the EPA is making a 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.

non-EGU industries:[4] reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

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 downwind 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 certain 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 III of this document 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.[5 6] 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.[7]

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.[8] Within 3 years of the EPA promulgating a new or revised NAAQS, all states are required to provide SIP submittals, often referred to as ''infrastructure SIPs,'' addressing certain requirements, including the good neighbor provision. *See* CAA section 110(a)(1) and (2). The EPA must either approve or disapprove such submittals or make a finding that a state has failed to submit a complete SIP revision. As with any other type of SIP under the Act, when the EPA disapproves an interstate transport SIP or finds that a state failed to submit an interstate transport SIP, the CAA requires the EPA to issue a FIP to directly implement the measures necessary to eliminate significant contribution under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this rule, the EPA is finalizing requirements to fully address good neighbor obligations for the covered states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c). By eliminating significant contribution from these upwind states, this rule 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. At any time after the effective date of this rule, states may submit a Good Neighbor SIP to replace the FIP requirements contained in this rule, subject to EPA approval under CAA section 110(a).

The EPA conducted air quality modeling for the 2023 and 2026 analytic years to identify (1) the downwind areas identified as ''receptors'' (which are associated with monitoring sites) 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. We use the term ''downwind'' to describe those states or areas where a receptor is located, and we use the term ''upwind'' to describe states whose emissions are linked to one or more receptors. States may be both downwind and upwind depending on the receptor or linkage in question. Section IV of this document provides a full description of the results of the EPA's updated air quality modeling and relevant analyses for the rulemaking, including a discussion of how updates to the modeling and air quality analysis following the proposed rule have resulted in some modest changes in the overall geography of the final rule. Based on the EPA's air quality analysis, the 23 upwind states covered in this action are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in downwind states. The EPA intends to expeditiously review the updated air quality modeling and related analyses to address potential good neighbor requirements of six additional states—Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming—in a subsequent action. The EPA had previously approved 2015 ozone transport SIPs submitted by Oregon and Delaware, but in the proposed FIP action the EPA found these states potentially to be linked in the modeling supporting our proposal. We proposed to issue an error correction for our prior approval of Delaware's 2015 ozone transport SIP; however, in this final rule, the EPA is withdrawing the proposed error correction and the proposed FIP for Delaware, because our updated modeling for this final rule confirms that Delaware is not linked above the 1 percent of NAAQS threshold (*see* section III.C.1 of this document for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

1. Emissions Limitations for EGUs Established by the Final Rule

In this rule, the EPA is issuing FIP requirements that apply the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program as revised in the rule to EGU sources within the borders of the following 22 states: Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. Implementation of the revised trading program provisions begins in the 2023 ozone season.

The EPA is expanding the CSAPR NO_X Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require power plants within the borders of the 22 states listed in the previous paragraph to participate in an expanded and 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 the following 12 states currently participating in the Group 3 Trading Program under existing FIPs remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland,

[4] We use the terms ''emissions limitation'' and ''emissions limit'' to refer to both numeric emissions limitations and control technology requirements that specify levels of emissions reductions to be achieved.

[5] 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.

[6] 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.

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

[8] 42 U.S.C. 7410(a)(2)(D)(i)(I).

Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs also require affected EGUs within the borders of the following seven 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, Texas, and Wisconsin.[9] Finally, the EPA is issuing new FIPs for EGUs within the borders of three states not currently covered by any existing CSAPR trading program for seasonal NO_X emissions: Minnesota, Nevada, and Utah. Sources in these states will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[10] Refer to section VI.B of this document for details on EGU regulatory requirements.

2. Emissions Limitations for Industrial Stationary Point Sources Established by the Final Rule

The EPA is issuing FIP requirements that include new NO_X emissions limitations for industrial or non-EGU sources in 20 states, with sources expected to demonstrate compliance no later than 2026. The EPA is requiring emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia and West Virginia.

The EPA is establishing emissions limitations for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. Refer to Table II.A–1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this rule.

B. Summary of the Regulatory Framework of the Rule

The EPA is applying the 4-step interstate transport framework developed and used in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules 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 define and implement good neighbor obligations for the 2015 ozone NAAQS. The four steps are as follows: (Step 1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (Step 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 rule as in prior transport rules beginning with CSAPR in 2011, above a contribution threshold of 1 percent of the NAAQS); (Step 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 through a multifactor analysis; and (Step 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. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to the provisions of the rule; additional details regarding the EPA's approach are found in section III of this document.

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 and 2026.[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 of projected ozone concentrations was then repeated for 2026.

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, the 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 4-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 the EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA finds that the following 23 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, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

There are locations in California to which Oregon contributes greater than 1 percent of the NAAQS; the EPA

[9] Five of these seven states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) currently participate in the Federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update. The FIPs required under this rule amend the existing FIPs for these 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 required in this action constitute new FIPs for these states. The EPA will cease implementation of the state Group 2 trading programs included in the two states' SIPs on the effective date of this rule.

[10] Three states, Kansas, Iowa, and Tennessee, will remain in the Group 2 Trading Program.

[11] These 2 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, and August 3, 2027, for areas classified as Serious nonattainment. *See* 83 FR 25776.

[12] The EPA performed air quality modeling for 2032 in the proposed rulemaking, but 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. The modeling of 2032 done at proposal using the 2016v2 platform does not constitute or represent any final agency determinations respecting air quality conditions or regulatory judgments with respect to good neighbor obligations or any other CAA requirements.

[13] *See* section IV.F of this document for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

proposed that downwind areas represented by these monitoring sites in California should not be considered interstate ozone transport receptors at Step 1. However, the EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

Based on the air quality analysis presented in section IV of this document, the EPA finds that, with the exception of Alabama, Minnesota, and Wisconsin, the states found linked in 2023 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. As a result, the EPA's evaluation of significantly contributing emissions at Step 3 for Alabama, Minnesota, and Wisconsin is limited to emissions reductions achievable by the 2023 and 2024 ozone seasons.

At the third step of the 4-step framework, the EPA applied a multifactor 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. The EPA is applying the multifactor test described in section V.A of this document to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,[14] as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in 2023 and future years 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 V of this document and supported by the ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Final Rule TSD'' (Mar. 2023), hereinafter referred to as the EGU NO_X Mitigation Strategies Final Rule TSD, included in the docket for this action, the EPA determines 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. *See* section V.B.1 of this document for a full discussion of EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NO_X emissions reduction potential from EGUs—among the uniform mitigation measures assessed for the covered region—and the most corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA is making a finding 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 the 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.[15] 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 rulemaking, the EPA is addressing good neighbor obligations for the more protective 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in downwind states under that NAAQS. As further discussed in section V of this document, 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. In this rule, the EPA is requiring emissions performance levels for 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 V of this document, the EPA finds 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 22 states linked to downwind

[14] The EPA included emissions reductions from the potential installation of SCRs at all affected large coal-fired EGUs in the 2026 analytic year for the purposes of assessing significant contribution to nonattainment and interference with maintenance, which is consistent with the associated attainment date. However, in response to comments identifying potential supply chain and outage scheduling challenges if the full breadth of these assumed SCR installations were to occur, the EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states.

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

nonattainment or maintenance in 2023 (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin). For 19 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, 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, for the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact in providing ozone air quality improvements in affected downwind states. Once the EPA identified the industries, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[16] [17] This information helped shape the proposal and final rule. To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved SIPs, consent decrees, and permit limits. That evaluation is detailed in the ''Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Dec. 2021), hereinafter referred to as the Proposed Non-EGU Sectors TSD, prepared for the proposed FIP.[18]

In this final rule, the EPA is retaining the industries and many of the emissions unit types included in the proposal in its findings of significant contribution at Step 3, as discussed in section V of this document. As discussed in the memorandum for the final rule, titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the Control Measures Database,[19] to estimate NO_X emissions reductions and costs for the year 2026. In this final rule, the EPA made changes to the applicability criteria and emissions limits following consideration of comments on the proposal and reassessed the overall non-EGU emissions reduction strategy based on the factors at Step 3 to render a judgment as to whether the level of emissions control that would be achievable from these units meets the criteria for ''significant contribution.'' In the final rule, we affirm our proposed determinations of which industries and emissions units are potentially impactful and warrant further analysis at Step 3, and we find that the available emissions reductions are cost-effective and make meaningful improvements at the identified downwind receptors. For a detailed discussion of the changes, between the proposal and this final rule, in emissions unit types included and in emissions limits, see section VI.C. of this document.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to evaluate the air quality improvements anticipated to result from the implementation of the selected EGU and non-EGU emissions reduction strategies. See section V.D of this document.[20] We also used AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is a less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that 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) to all of linked receptors. The EPA's over-control analysis, discussed in section V.D.4 of this document, shows that the control stringencies for EGU and non-EGU sources in this final rule 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.

Based on the multi-factor test applied to both EGU and non-EGU sources and

[16] The memorandum is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150*.

[17] This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that had 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. This information helped shape the proposed rule.

[18] The TSD is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

[19] More information about the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution*.

[20] The use of AQAT and other simplified modeling tools to generate ''appropriately reliable projections of air quality conditions and contributions'' when there is limited time to conduct full-scale photochemical grid modeling was upheld by the D.C. Circuit in *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The EPA has used AQAT for the purpose of air quality and overcontrol assessments at Step 3 in the prior CSAPR rulemakings, and we continue to find it reliable for such purposes. We discuss the calibration of AQAT for this action and the multiple sensitivity checks we performed to ensure its reliability in the Ozone Transport Policy Analysis Final Rule TSD in the docket. Because we were able to conduct a photochemical grid modeling run of the 2026 final rule policy scenario, these results are also included in the docket and confirm the regulatory conclusions reached with AQAT. *See* section VIII of this document and Appendix 3A of the Final Rule RIA for more information.

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 23 upwind states subject to EGU and non-EGU emissions reductions requirements under the rule. For additional details about the multi-factor test and the over-control analysis, *see* the document titled ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, Ozone Transport Policy Analysis Proposed Rule TSD'' (Mar. 2023), hereinafter referred to as Ozone Transport Policy Analysis Final Rule TSD, included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA is including enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 23 states. Specifically, the FIPs require covered power plants within the borders of 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) 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 the following 12 states currently participating in the Group 3 Trading Program will remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[21] and affected EGUs within the borders of three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA is revising other aspects of the Group 3 trading program to better ensure that this method of implementation at Step 4 provides a durable remedy for the elimination of the amount of emissions deemed to constitute significant contribution at Step 3 of the interstate transport framework. These enhancements, summarized later in this section, are designed to operate together to maintain that degree of control stringency over time, thus improving emissions performance at individual units and offering a necessary measure of assurance that NO_X pollution controls will be operated throughout each ozone season, as described in section VI.B of this document. This rulemaking does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program. Aside from the seven states moving from the Group 2 trading program to the Group 3 trading program under the final rule, this rule otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

The EPA is establishing preset ozone season NO_X emissions budgets for each ozone season from 2023 through 2029, using generally the same Group 3 trading program budget-setting methodology used in the Revised CSAPR Update, as explained in section VI.B of this document and as shown in Table I.B–1. The preset budgets for the 2026 through 2029 ozone seasons incorporate EGU emissions reductions to eliminate significant contribution and also take into account a substantial number of known retirements over that period to ensure the elimination of significant contribution is maintained as intended by this rule. These budgets serve as floors and may be supplanted by a budget that the EPA calculates for that control period using more recent information (a ''dynamic budget'') if that dynamic budget yields a higher level of allowable emissions—still consistent with the Step 3 level of emissions control stringency—than the preset budget. As reflected in Table I.B–1, and accounting for both the stringency of the rule and known fleet change, the 2026 preset budget is 23 percent lower than the 2025 preset budget; the 2027 preset budget is 20 percent lower than the 2026 preset budget; the 2028 preset budget is 4 percent lower than the 2027 preset budget; and the 2029 preset budget is 8 percent lower than the 2028 preset budget.

While it is possible that additional EGUs may seek to retire in this 2026–2029 period than are currently scheduled and captured in the preset emissions budgets, it is also possible that EGUs with currently scheduled retirements may adjust their retirement timing to accommodate the timing of replacement generation and/or transmission upgrades necessitated by their retirement. While the EPA designed this final rule to provide preset budgets through 2029 to incorporate known retirement-related emissions reductions to ensure the elimination of significant contribution as identified at Step 3 is maintained over time, the use of these floors also provides generators and grid operators enhanced certainty regarding the minimum amount of allowable NO_X emissions for reliability planning through the 2020s. By providing the opportunity for dynamic budgets to subsequently calibrate budgets to any unforeseen increases in fleet demand, it also ensures this rule will not interfere with ongoing retirement scheduling or adjustments and thus is robust to future uncertainty during a transition period.

The EPA also believes the likelihood and magnitude of a scenario in which a state's preset emissions budgets during this period would authorize more emissions than the corresponding dynamic budget is low. As described elsewhere, dynamic budgets are incorporated to best calibrate the rule's stringency to future unknown changes to the fleet. The circumstances in which a dynamic budget would produce a level of allowable emissions less than preset budgets is most pronounced for future periods in which there is a high degree of unknown retirements (increasing the risk that budgets are not appropriately calibrated to the reduced fossil fuel heat input post retirement). However, the 2026–2029 period presents a case where retirement planning has been announced with greater lead time than normal due to a combination of utility 2030 decarbonization commitments, and Effluent Limitation Guideline (ELG) and Coal Combustion Residual (CCR) alternative compliance pathways available to units planning to cease combustion of coal by December 31, 2028. For each of these existing rules, facilities that are planning to retire have already conveyed that intention to EPA in order to take advantage of the alternative compliance pathways

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

available to such facilities.[22] Therefore, the likelihood of unknown retirements—leading to lower dynamic budgets—is much lower than typical for this time horizon. This makes EPA's balanced use of preset emissions budgets or dynamic budgets if they exceed preset levels a reasonable mechanism to accommodate planning and fleet transition dynamics during this period. The need and reasoning for the limited-period preset budget floor is further discussed in section VI.B.4.

For control periods in 2030 and thereafter, the emissions budgets will be the amounts calculated for each state and noticed to the public roughly one year before the control period, using the dynamic budget-setting methodology. In this manner, the stringency of the program will be secured and sustained in the dynamic budgets of this program, regardless of whatever EGU transition activities ultimately occur in this 2026–2029 transition period.

TABLE I.B–1—PRESET CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS (TONS) FOR 2023 THROUGH 2029 CONTROL PERIODS *

State	2023 State budget	2024 State budget	2025 State budget	2026 State budget **	2027 State budget **	2028 State budget **	2029 State budget **
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

* Further information on the state-level emissions budget calculations pertaining to Table I.B–1 is provided in section VI.B.4 of this document as well as the Ozone Transport Policy Analysis Final Rule TSD. Further information on the 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 VI.B.9 of this document.

** As described in section VI of this document, the budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

The budget-setting methodology that the EPA will use to determine dynamic budgets for each control period starting with 2026 is an extension of the methodology used to determine the preset budgets and will be used routinely to determine 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 stringency of the dynamic emissions budgets will 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. As already noted, for the control periods in which both preset budgets and dynamic budgets are determined for a state (*i.e.,* 2026 through 2029), the state's dynamic budget will apply only if it is higher than the state's preset budget. *See* section VI.B of this document for additional discussion of the EPA's method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

In conjunction with the levels of the emissions budgets, the carryover of unused allowances for use in future control periods as banked allowances 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. Unrestricted banking of allowances allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. To prevent this outcome, the EPA is also revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances using a target percentage of 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years.

As an enhancement to the structure of the trading program originally promulgated in the Revised CSAPR Update, the EPA is also establishing backstop daily emissions rates for coal

[22] Notices of Planned Participation for the ELG Reconsideration Rule were due October 31, 2021 (85 FR 64708, 64679). For the CCR Action, facilities had to indicate their future plans to cease receipt of waste by April 11, 2021 (85 FR 53517).

steam EGUs greater than or equal to 100 MW in covered states. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period.

The backstop daily emissions rates work in tandem with the ozone season emissions budgets to ensure the elimination of significant contribution as determined at Step 3 is maintained over time and more consistently throughout each ozone season. They will offer downwind receptor areas a necessary measure of assurance that they will be protected on a daily basis during the ozone season by more continuous and consistent 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.[23] In addition to maintaining a mass-based seasonal requirement, this rule will achieve a much more consistent level of emissions control in line with our Step 3 determination of significant contribution while maintaining compliance flexibility consistent with that determination. These trading program improvements will promote consistent emissions control performance across the power sector in the linked upwind states, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA is including enforceable emissions control requirements that will apply during the ozone season (annually from May to September) for nine non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 20 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states that meet the relevant applicability criteria. Thus, the emissions limitations for non-EGU sources and associated compliance requirements would apply in all 20 states listed in this paragraph, even if some of these states do not currently have any existing emissions units meeting the applicability criteria for the identified industries.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this rule, the EPA has identified the 2026 ozone season as a reasonable compliance date for industrial sources. The EPA is therefore finalizing control requirements for non-EGU sources that take effect in 2026. However, in recognition of comments and additional information indicating that not all facilities may be capable of meeting the control requirements by that time, the final rule provides a process by which the EPA may grant compliance extensions of up to 1 year, which if approved by the EPA, would require compliance no later than the 2027 ozone season, followed by an additional possible extension of up to 2 more years, where specific criteria are met. For sources located in the 20 states listed in the previous paragraph, the EPA is finalizing the NO_X emissions limits listed in Table I.B–2 for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the NO_X emissions limits listed in Table I.B–3 for kilns in Cement and Cement Product Manufacturing; the NO_X emissions limits listed in Table I.B–4 for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the NO_X emissions limits listed in Table I.B–5 for furnaces in Glass and Glass Product Manufacturing; the NO_X emissions limits listed in Table I.B–6 for boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and the NO_X emissions limits listed in Table I.B–7 for combustors and incinerators in Solid Waste Combustors or Incinerators.

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

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

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

Kiln type	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

[23] *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.

Based on evaluation of comments received, the EPA is not, at this time, finalizing the source cap limit as proposed at 87 FR 20046 (*see* section VII.C.2 of the April 6, 2022, Proposal).

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

Emissions unit	NO_X emissions standard or requirement (lb/mmBtu)
Reheat furnace	Test and set limit based on installation of Low-NO_X Burners.

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

Furnace type	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	7.0

TABLE I.B–6—SUMMARY OF NO_X EMISSIONS LIMITS FOR BOILERS IN IRON AND STEEL AND FERROALLOY MANUFACTURING, METAL ORE MINING, 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

TABLE I.B–7—SUMMARY OF NO_X EMISSIONS LIMITS FOR COMBUSTORS AND INCINERATORS IN SOLID WASTE COMBUSTORS OR INCINERATORS

Combustor or incinerator, averaging period	NO_X emissions limit (ppmvd)
ppmvd on a 24-hour block averaging period	110
ppmvd on a 30-day rolling averaging period	105

Section VI.C of this document provides an overview of the applicability criteria, compliance assurance requirements, and the EPA's rationale for establishing these emissions limits and control requirements for each of the non-EGU industries covered by the rule.

The remainder of this preamble is organized as follows: section II of this document outlines general applicability criteria and describes the EPA's legal authority for this rule and the relationship of the rule to previous interstate ozone transport rulemakings. Section III of this document describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as the EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this rule. Section IV of this document describes the Agency's analyses of air quality data to inform this rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the rule, as well as the EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states. Section V of this document describes the EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits. Section VI of this document 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 VII of this document discusses the environmental justice analysis of the rule, as well as outreach and engagement efforts. Section VIII of this document describes the expected costs, benefits, and other impacts of this rule. Section IX of this document provides a summary of changes to the existing regulatory text applicable to the EGUs covered by this rule; and section X of this document discusses the statutory and executive orders affecting this rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this final 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 recommended by OMB's Circular A–4, of the health and climate benefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2023. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the final rule. These results present an incomplete overview of the effects of the rule because important categories of benefits—including benefits from reducing 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 rule to be more net beneficial than this table reflects.

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

[Millions 2016$, discounted to 2023] [a]

	3% Discount rate	7% Discount rate
Present Value:		
Health Benefits [b]	$200,000	$130,000
Climate Benefits [c]	15,000	15,000
Compliance Costs [d]	14,000	9,400
Net Benefits	200,000	140,000
Equivalent Annualized Value:		
Health Benefits	13,000	12,000
Climate Benefits	970	970
Compliance Costs	910	770
Net Benefits	13,000	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 ozone and $PM_{2.5}$ concentrations. The health benefits are associated with two 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.
[c] Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC–CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.
[d] The costs presented in this table are consistent with the costs presented in Chapter 4 of the *Regulatory Impact Analysis (RIA).* To estimate these annualized costs for EGUs, the 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 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

As shown in Table I.C–1, the PV of the monetized health benefits, associated with reductions in ozone and $PM_{2.5}$ concentrations, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits, associated with reductions in GHG emissions, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

II. General Information

A. Does this action apply to me?

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

TABLE II.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Metal Ore Mining	2122
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
Solid Waste Combustors and Incinerators	562213

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this rule. Other types of entities not listed in the table could also be regulated. To determine whether your EGU entity is regulated by this rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which are unchanged in this rule. If you have questions regarding the applicability of this 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 finds that emissions reductions are required from EGU and non-EGU sources in a total of 23 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 FIP requirements for 23 states: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

The EPA is revising the existing CSAPR Group 3 Trading Program to include additional states beginning in the 2023 ozone season. EGUs in three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will be added to the CSAPR Group 3 Trading Program under this rule. EGUs in twelve states currently participating in the Group 3 Trading Program will remain in the program under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. EGUs in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin) will transition from the CSAPR Group 2 Trading Program to the CSAPR Group 3 Trading Program under this rule beginning in the 2023 ozone season. The EPA is establishing 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 is establishing 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 establishing a backstop daily emissions rate of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions rate will first apply in 2024 for coal-fired steam sources with existing SCRs, and in the second control period in which a new SCR operates, but not later than 2030, for those currently without SCRs.

This rule establishes emissions limitations for non-EGU sources in 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. In these states, the EPA is establishing control requirements for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. *See* Table II.A–1 in this document for a list of NAICS codes for each entity included for regulation in this rule.

This rule reduces 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 air quality issues addressed by this rule are included in section III of this document.

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

The statutory authority for this 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 rule. The most relevant portions of CAA section 110 are subsections 110(a)(1), 110(a)(2) (including 110(a)(2)(D)(i)(I)) and 110(c)(1)).

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.[24] 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.[25]

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.[26] It includes a list of specific elements that ''[e]ach such plan'' must address.[27]

CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within 2 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.[28]

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, provides the primary basis for this rule.[29] 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].'' [30] 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.''

[24] 42 U.S.C. 7410(a)(1).

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

[26] 42 U.S.C. 7410(a)(2).

[27] The 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).

[28] 42 U.S.C. 7410(c)(1).

[29] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[30] *Id.*

Once the EPA promulgates a NAAQS, the EPA must designate areas as being in ''attainment'' or ''nonattainment'' of the NAAQS, or ''unclassifiable.'' CAA section 107(d).[31] 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.[32] In general, states with nonattainment areas classified as Moderate or higher must submit plans to the EPA to bring these areas into attainment according to the statutory schedule. CAA section 182.[33] 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).[34]

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.[35] Pursuant to this section, the 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 to make certain other changes to its regulations under 40 CFR parts 52, 75, 78, and 97, to effectuate the purposes of the Act. Such changes are discussed in section IX of this document.

Tribes are not required to submit state implementation plans. However, as explained in the 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 the EPA's approval of, an implementation plan. *See* 40 CFR 49.11(a); *see also* CAA section 301(d)(4).[36] In the proposed rule, the EPA proposed an ''appropriate or necessary'' finding under CAA section 301(d) and proposed tribal FIP(s) as necessary to implement the relevant requirements. The EPA is finalizing these determinations, as further discussed in section III.C.2 of this document.

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

The EPA has issued several previous 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.[37] 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.[38] 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).

The EPA's next rule addressing the good neighbor provision, CAIR, was promulgated in 2005 and addressed both the 1997 fine particulate matter ($PM_{2.5}$) NAAQS and 1997 ozone NAAQS.[39] 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.[40] On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.[41] CAIR was remanded to EPA by the D.C. Circuit in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified on reh'g,* 550 F.3d 1176 (D.C. Cir. 2008). 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.[42]

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.[43] 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.[44] 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.[45] However, this decision was reversed in April 2014 by the Supreme Court, which largely upheld the rule, including the 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

[31] 42 U.S.C. 7407(d).

[32] 42 U.S.C. 7511, 7511a.

[33] 42 U.S.C. 7511a.

[34] 42 U.S.C. 7511(b).

[35] 42 U.S.C. 7601(a)(1).

[36] 42 U.S.C. 7601(d)(4).

[37] *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).

[38] ''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 the EPA's most recent trading programs are discussed in section VI.B.1.a of this document.

[39] *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).

[40] 70 FR 21147 (April 25, 2005).

[41] 71 FR 25328 (April 28, 2006).

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

[43] 76 FR 48208.

[44] CSAPR was revised by several rulemakings after its initial promulgation 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).

[45] 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 the 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).

generally affirmed the EPA's interpretation of various statutory provisions and the 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 the 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.[46]

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.[47] 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.[48] The EPA aligned the analysis and implementation of the CSAPR Update with the 2017 ozone season to assist downwind states with timely attainment of the 2008 ozone NAAQS.[49] 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 2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update.[50]

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 because 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.[51]

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.[52] 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 would 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 the 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 the EPA, would replace the Revised CSAPR Update FIP for that state.

On March 3, 2023, the D.C. Circuit Court of Appeals denied the Midwest Ozone Group's (MOG) petition for review of the Revised CSAPR Update. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The court noted that it has "exhaustively" addressed the interstate transport framework before, citing relevant cases, and "incorporate them herein by reference." Slip Op. 1 n.1. In response to MOG's arguments, the court upheld the Agency's air quality analysis. *Id.* at 10–11. The court noted that in light of the statutory timing framework and court-ordered schedule the EPA was under, the Agency's methodological choices were reasonable and provided "an appropriately reliable projection of air quality conditions and contributions in 2021." *Id.* at 11–12.

III. Air Quality Issues Addressed and Overall Rule Approach

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

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

[47] 81 FR 74504.

[48] 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.

[49] 81 FR 74516. The 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. 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.

[50] *Determination Regarding Good Neighbor Obligations for the 2008 Ozone National Ambient Air Quality Standard,* 83 FR 65878, 65882 (December 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.

[51] Subsequently, the D.C. Circuit made clear in a decision reviewing the 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).

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

level.[53] 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).[54] In general, areas that exceed the ozone standard are designated as nonattainment areas, pursuant to the designations process under CAA section 107(d), and are subject to heightened planning requirements depending on the 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 Greenhouse Gas 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.[55] (80 FR 65300). The U.S. Global Change Research Program's *Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*[56] and *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*[57] reinforced these findings. 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.[58 59 60] Climate 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). The EPA responds to comments received on the impacts of climate change on ozone formation in section 11 of the *Response to Comments* (*RTC*) document.

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.[61] 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, in conjunction with variable meteorological conditions. 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[62] continue to show the importance of NO_X emissions for ozone transport. This analysis is included in the docket for this rulemaking.

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 of the 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.[63]

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, the 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

[53] 80 FR 65291.

[54] 40 CFR part 50, appendix P.

[55] 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. O3 by scenario and across models and years, within the overall signal of higher summer O3 concentrations in a warmer climate.

[56] U.S. Global Change Research Program (USGCRP), 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *https://dx.doi.org/10.7930/J0R49NQX.*

[57] USGCRP, 2018: *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, 1515 pp. doi: 10.7930/NCA4.2018.

[58] 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

[59] 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.

[60] 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

[61] 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.

[62] Available in the docket for the October 2015 Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone at *https://www.regulations.gov/docket/EPA-HQ-OAR-2008-0699.*

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

determined by the amount of VOC emissions.[64] The EPA and others have long regarded NO_X to be the more significant ozone precursor in the context of interstate ozone transport.[65]

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 rule. As described in section V.A of this document, 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 demonstrates that regional ozone concentrations affecting the vast majority of the downwind areas of air quality concern are NO_X-limited, rather than VOC-limited. Therefore, the 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. The potential impacts of NO_X mitigation strategies from other sources are discussed in section V.B of this document.

In section V of this document, the 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 included in this rule will provide meaningful improvements in air quality at the downwind receptors. Based on the implementation schedule established in section VI.A of this document, the EPA finds that the regulatory requirements included in the 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 certain 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[66] in the docket for this rulemaking for more information on the human health and ecosystem effects associated with ambient ozone exposure.

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 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 rule is an example of air pollution control actions implemented by the Federal Government in support of the more protective 2015 ozone NAAQS, and populations living in downwind ozone nonattainment and maintenance areas are expected to benefit from improved air quality that will result from reducing ozone transport. Further discussion of the environmental justice analysis of this rule is located in section VII of this document and in the accompanying regulatory impact analysis, titled ''Regulatory Impact Analysis for Final Federal Good Neighbor 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 subject rulemaking is to protect public health and the environment by eliminating significant contribution from 23 states to nonattainment or maintenance of the 2015 ozone NAAQS to meet the requirements of the CAA's interstate transport provision. In this 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.

The EPA responds to other comments received on the health and environmental impacts of ozone exposure in section 11 of the *RTC* document.

B. Final 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 1998 NO_X SIP Call and the 2005 CAIR. The Agency built upon this framework and further refined the methodology for addressing interstate transport obligations in subsequent rules such as CSAPR in 2011, the CSAPR Update in 2016, and the Revised CSAPR Update in 2021.[67] In CSAPR, the EPA first articulated a ''4-step framework'' within which to assess interstate transport obligations for ozone. In this rule 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.

Comment: The EPA received comments supporting the Agency's use of the 4-step interstate transport framework as a permissible method for assigning the required amount of

[64] ''Ozone Air Pollution.'' *Introduction to Atmospheric Chemistry,* by Daniel J. Jacob, Princeton University Press, Princeton, New Jersey, 1999, pp. 231–244.

[65] 81 FR 74514.

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

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

emissions reductions necessary to eliminate upwind states' significant contribution. Commenters also noted that the 4-step interstate transport framework was reviewed by the Supreme Court in *EPA vs. EME Homer City Generation,* 572 U.S. 489 (2014), and upheld. However, other commenters took exception to the overall approach of this proposed action. These commenters alleged that the EPA is ignoring the ''flexibility'' in addressing good neighbor obligations that it had purportedly suggested to states would be permissible in memoranda that the EPA issued in 2018. Commenters also raised concerns that the air quality modeling (2016v2) the EPA used to propose to disapprove SIP submittals and as the basis for the proposed FIP was not available to states at the time they made their submissions and that the changes in results at Steps 1 and 2 from prior rounds of modeling rendered the new modeling unreliable. Commenters also raised a number of arguments that the EPA should allow states an additional opportunity to submit SIPs before promulgating a FIP, advocated that the EPA should issue a ''SIP call'' under CAA section 110(k)(5), asked for the EPA to issue new or more specific guidance, or otherwise suggested that the EPA should defer acting to promulgate a FIP at this time.

Response: As an initial matter, comments regarding the EPA's basis for disapproving SIPs are beyond the scope of this action.[68] To the extent these comments relate to the legal basis for the EPA to promulgate a FIP, the EPA disagrees that it is acting in a manner contrary to the memoranda it released in 2018 related to good neighbor obligations for the 2015 ozone NAAQS. Arguments that the EPA must or should allow states to re-submit SIP submissions based on the most recent modeling information before the EPA promulgates a FIP ignore the plain language of the statute and relevant caselaw. CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval. No provision of the Act requires the EPA to give states an additional opportunity to prepare a new SIP submittal once the EPA has proposed a FIP or proposed disapproval of a SIP submittal. Comments regarding the timing of the EPA's actions and calls for the EPA to allow time for states to resubmit SIPs are further addressed in *RTC* sections 1.1 and 2.4.

With regard to the need for the EPA to develop and issue guidance in addressing good neighbor obligations, in *EPA* v. *EME Homer City Generation, L.P.,* the Supreme Court held that ''nothing in the statute places the EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.'' [69] While we have taken a different approach in some prior rulemakings by providing states with an opportunity to submit a SIP after we quantified the states' budgets (*e.g.,* the NO_X SIP Call and CAIR [70]), the CAA does not require such an approach.

2018 Memoranda. As commenters point out, the EPA issued three ''memoranda'' in 2018 to provide some assistance to states in developing these SIP submittals.[71] Each memorandum made clear that the EPA's action on SIP submissions would be through a separate notice-and-comment rulemaking process and that SIP submissions seeking to rely on or take advantage of any so-called ''flexibilities'' in these memoranda would be carefully reviewed against the relevant legal requirements and technical information available to the EPA at the time it would take such rulemaking action. Further, certain aspects of discussions in those memoranda were specifically identified as not constituting agency guidance (especially Attachment A to the March 2018 memorandum, which comprised an unvetted list of external stakeholders' ideas). And, although outside the scope of this action, as the EPA has explained in disapproving states' SIP submittals, those submittals did not meet the terms of the August 2018 or October 2018 memoranda addressing contribution thresholds and maintenance receptors, respectively.

Commenters mistakenly view Attachment A to the March 2018 memorandum as constituting agency guidance. This memorandum was primarily issued to share modeling results for 2023 that represented the best information available to the Agency as of March 2018, while Attachment A then listed certain ideas from certain stakeholders that the EPA said could be further discussed among states and stakeholders. The EPA disagrees with commenters' characterization of the EPA's stance regarding these so-called ''flexibilities'' listed (without analysis) in Attachment A. The March 2018 memorandum provided, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision.'' The EPA again affirms that the concepts listed in Attachment A to the March 2018 memorandum require unique consideration, and these ideas do not constitute agency guidance with respect to transport obligations for the 2015 ozone NAAQS. Attachment A to the March 2018 memorandum identified a ''Preliminary List of Potential Flexibilities'' that could potentially inform SIP development. However, the EPA made clear in both the March 2018 memorandum [72] and in Attachment A that the list of ideas was not endorsed by the Agency but rather ''comments provided in various forums'' on which the EPA sought ''feedback from interested stakeholders.'' [73] Further, Attachment A stated, ''EPA is not at this time making any determination that the ideas discussed below are consistent with the requirements of the CAA, nor are we specifically recommending that states use these approaches.'' [74] Attachment A to the March 2018 memorandum, therefore, does not

[68] We nonetheless further respond to comments regarding the timing and sequence of the EPA's SIP and FIP actions, the relevance of judicial consent decrees, the requests for a SIP call, and related comments—to the extent any of these issues are within scope of the present action—in Sections 1 and 2 of the *RTC* document located in the docket for this action.

[69] 572 U.S. 489, 510 (2014). ''Nothing in the Act differentiates the Good Neighbor Provision from the several other matters a State must address in its SIP. Rather, the statute speaks without reservation: Once a NAAQS has been issued, a State 'shall' propose a SIP within three years, § 7410(a)(1), and that SIP 'shall' include, among other components, provisions adequate to satisfy the Good Neighbor Provision, § 7410(a)(2).'' *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. at 515.

[70] For information on the NO_X SIP call see 63 FR 57356 (October 27, 1998). For information on CAIR *see* 70 FR 25162 (May 12, 2005).

[71] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I) (March 27, 2018) (''March 2018 memorandum''); Analysis of Contribution Thresholds 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, August 31, 2018) (''August 2018 memorandum''); 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''). These are available in the docket or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs*.

[72] ''In addition, the memorandum is accompanied by Attachment A, which provides a preliminary list of potential flexibilities in analytical approaches for developing a good neighbor SIP that may warrant further discussion between EPA and states.'' March 2018 memorandum at 1.

[73] March 2018 memorandum, Attachment A at A–1.

[74] *Id.*

constitute agency guidance, but was intended to generate further discussion around potential approaches to addressing ozone transport among interested stakeholders. The EPA emphasized in these memoranda that such alternative approaches must be technically justified and appropriate in light of the facts and circumstances of each particular state's submittal. To the extent states sought to develop or rely on one or more of these ideas in support of their SIP submissions, the EPA reviewed their technical and legal justifications for doing so.[75]

Regarding the October 2018 memorandum, that document recognized that states may be able to demonstrate in their SIPs that conditions exist that would justify treating a monitoring site as not being a maintenance receptor despite results from our modeling methodology identifying it as such a receptor. The EPA explained that this demonstration could be appropriate under two circumstances: (1) the site currently has ''clean data'' indicating attainment of the 2015 ozone NAAQS based on measured air quality concentrations, or (2) the state believes there is a technical reason to justify using a design value from the baseline period that is lower than the maximum design value based on monitored data during the same baseline period. To justify such an approach, the EPA anticipated that any such showing would be based on an analytical demonstration that (1) meteorological conditions in the area of the monitoring site were conducive to ozone formation during the period of clean data or during the alternative base period design value used for projections; (2) ozone concentrations have been trending downward at the site since 2011 (and ozone precursor emissions of NO_X and VOC have also decreased); and (3) emissions are expected to continue to decline in the upwind and downwind states out to the attainment date of the receptor. Although this is beyond the scope of this action, the EPA explained in its final SIP disapproval action that no state successfully demonstrated that one of these alternative approaches is justified. In this action, our analysis of the air quality data and projections in section IV of this document indicate that trends in historic measured data do not necessarily support adopting a less stringent approach for identifying maintenance receptors for purposes of the 2015 ozone NAAQS. In fact, as explained in section III.B.1.a and IV.D of this document, the EPA has found in its analysis for this final rule that, in general, recent measured data from regulatory ambient air quality ozone monitoring sites suggest that a number of receptors with elevated ozone levels will persist in 2023 even though our traditional methodology at Step 1 did not identify these monitoring sites as receptors in 2023. Thus, the EPA is not acting inconsistently with that memorandum—the factual conditions that would need to exist for the suggested approaches of that memorandum to be applicable have not been demonstrated as being applicable or appropriate based on the relevant data.

Regarding the August 2018 memorandum, as discussed in section IV.F.2 of this document, for purposes of Step 2 of our ozone transport evaluation framework, we are applying a 1 percent of NAAQS threshold rather than a 1 ppb threshold, as this memorandum had suggested might be appropriate for states to apply as an alternative. The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS contribution threshold at Step 2 to evaluate whether states are linked to downwind nonattainment and maintenance concerns for purposes of this FIP.

The approach of this FIP ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. Further, in this action the EPA is promulgating FIPs under the authority of CAA section 110(c). In doing so, the EPA has exercised its discretion to determine how to define and apply good neighbor obligations in place of the discretion states otherwise would exercise (subject to the EPA's approval as compliant with the Act). In general, the EPA is applying the 4-step interstate transport framework it devised over the course of its prior good neighbor rulemakings, including applying a consistent definition of nonattainment and maintenance-only receptors, and applying the 1 percent of NAAQS threshold at Step 2. The basis for these decisions is further explained in sections IV.F.1 and IV.F.2 of the document. These policy judgments reflect consistency with relevant good neighbor case law and past agency practice implementing the good neighbor provision as reflected in the original CSAPR, CSAPR Update, Revised CSAPR Update, and related rulemakings. Nationwide consistency in approach is particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving the collective emissions of many smaller contributors. Effective policy solutions to the problem of interstate ozone transport dating back to the NO_X SIP Call (63 FR 57356 (October 27, 1998)) have necessitated the application of a uniform framework of policy judgments, and the EPA's framework applied here has been upheld as ensuring an ''efficient and equitable'' approach. *See EME Homer City Generation, LP* v. *EPA,* 572 U.S. 489, 519 (2014).

Updated modeling. The EPA had originally provided 2023 modeling results in its March 2018 memorandum, which used a 2011-based platform. Many states used this modeling in providing good neighbor SIP submittals for the 2015 ozone NAAQS. While our action on the SIP submittals is not within scope of this action, commenters claim the use of new modeling or other information not available to states at the time they made their submittals renders this action promulgating a FIP unlawful. Notwithstanding whether that is an accurate characterization of the EPA's basis for disapproving the SIPs, we note that the court in *Wisconsin* rejected this precise argument against the CSAPR Update FIPs as a collateral attack on the SIP disapprovals. 938 F.3d at 336 (''That is the hallmark of an improper collateral attack. The true gravamen of the claim lies in the agency's failure to timely act upon the States' SIP submissions and, relatedly, its reliance on data compiled after the SIP action deadline. Both go directly to the legitimacy of the SIP denials.'').

Nonetheless, we offer the following explanation of the evolution of the EPA's understanding of projected air quality conditions and contributions in 2023 resulting from the iterative nature of our modeling efforts. These modeling efforts are further addressed in section IV of this document. We acknowledge that to evaluate transport SIPs and support our proposed FIP the EPA reassessed receptors at Step 1 and states' contribution levels at Step 2 through additional modeling (2016v2) before proposing this action and have reassessed again to inform the final action (2016v3). At proposal, we relied on CAMx Version 7.10 and the 2016v2 emissions platform to make updated determinations regarding which receptors would likely exist in 2023 and which states are projected to contribute above the contribution threshold to those receptors. As explained in the preamble of the EPA's proposed FIP and further detailed in the ''Air Quality

[75] *E.g.,* 87 FR 64423–64425 (Alabama); 87 FR 31453–31454 (California); 87 FR 9852–9854 (Illinois); 87 FR 9859–9860 (Indiana); 87 FR 9508, 9515 (Kentucky); 87 FR 9861–9862 (Michigan); 87 FR 9869–9870 (Ohio); 87 FR 9798, 9818–9820 (Oklahoma); 87 FR 31477–31481 (Utah); 87 FR 9526–9527 (West Virginia).

Modeling Technical Support Document for the Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards Proposed Rulemaking'' (Dec. 2021), hereinafter referred to as Air Quality Modeling Proposed Rule TSD, and the ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform'' (Dec. 2021), hereinafter referred to as the 2016v2 Emissions Inventory TSD, both available in the docket for this action (docket ID no. EPA–HQ–OAR–2021–0668), this modeling built off of previous modeling iterations used to support the EPA's action on interstate transport obligations. The EPA periodically refines its modeling to ensure the results are as indicative as possible of air quality in future years. This includes making any necessary adjustments to our modeling platform and updating our emissions inventories to reflect current information, including information submitted during public comments on proposed actions.

For this final rule, the EPA has evaluated a raft of technical information and critiques of its 2016v2 modeling provided by commenters on this action (as well as comments on the SIP actions) and has responded to those comments and incorporated updates into the version of the modeling used to support this final rule (2016v3). As explained in section IV.B of the document, in response to additional information provided by stakeholders following a solicitation of feedback during the release of the 2016v2 emissions inventory and during the comment periods on the proposed SIP actions, the EPA has reviewed and revised its 2016v2 modeling platform and input since the platform was made available for comment. The new modeling platform 2016v3 was developed from this input, and the modeling results using platform 2016v3 are available with this action. *See* section IV of this document for further discussion. Thus, the EPA's final rule is based on a comprehensive record of data and technical evaluation, including the updated modeling information used at proposal (2016v2), the comments received on that modeling, and the latest modeling used in this final rule (2016v3).

The changes in projected outcomes at Steps 1 and 2 are a product of these changes; these updates between the data released in 2018 to now are an outgrowth of this iterative process, including updating the platform from a 2011 to a 2016 base year, updates to the emissions inventory information and other updates. It is reasonable for the Agency to improve its understanding of a situation before taking final action, and the Agency uses the best information available to it in taking this action.

Further, these modeling updates have not uniformly resulted in new linkages—the 2016v2 modeling, for instance, corroborated the proposed approval of Montana and supported approval of Colorado's SIP in October of 2022.[76] Although some commenters indicate that our modeling iterations have provided differing outcomes and are therefore unreliable, this is not what the overall record indicates. Rather, in general, although the specifics of states' linkages may have changed to some extent, our modeling on the whole has provided consistent outcomes regarding which states are linked to downwind air quality problems. For example, the EPA's modeling shows that most states that were linked to one or more receptors using the 2011-based platform (*i.e.,* the March 2018 data release) are also linked to one or more receptors using the newer 2016-based platform. Because the new platform uses different meteorology (*i.e.,* 2016 instead of 2011), it is not unexpected that an upwind state would be linked to different receptors using 2011 versus 2016 meteorology. In addition, although a state may be linked to a different set of receptors, those receptors are within the same areas that have historically had a persistent air quality problem. Only three upwind states included in the FIP went from being unlinked to being linked in 2023 between the 2011-based modeling provided in the March 2018 memorandum and the 2016v3-based modeling—Alabama, Minnesota, and Nevada.

Additionally, we disagree with commenters who claim that the 2016v2 modeling results were sprung upon the states with the publication of the proposed SIP disapprovals. In fact, states had prior access to a series of data and modeling releases beginning as early as the publication of the 2016v1 modeling with the proposed Revised CSAPR Update in October 2020. States could have reviewed and used this technical information to understand and track how the EPA's modeling updates were affecting the list of potential receptors and linkages for the 2015 ozone NAAQS in the 2023 analytic year.

The 2016-based meteorology and boundary conditions used in the modeling have been available through the 2016v1 platform, which was used for the Revised CSAPR Update (proposed, 85 FR 68964; October 30, 2020). The updated emissions inventory files used in the current modeling were publicly released September 21, 2021, for stakeholder feedback, and have been available on our website since that time.[77] The CAMx modeling software that the EPA used has likewise been publicly available for over a year before this final rule was proposed on April 6, 2022. CAMx version 7.10 was released by the model developer, Ramboll, in December 2020. On January 19, 2022, we released on our website and notified a wide range of stakeholders of the availability of both the modeling results for 2023 and 2026 (including contribution data) along with many key underlying input files.[78]

By providing the 2016 meteorology and boundary conditions (used in the 2016v1 version) in fall of 2020, and by releasing updated emissions inventory information used in 2016v2 in September of 2021,[79] we gave states and other interested parties multiple opportunities prior to proposal of this rule on April 6, 2022, to consider how our modeling updates could affect their status for purposes of evaluating potential linkages for the 2015 ozone NAAQS. In this final rule, we have updated our modeling to 2016v3, incorporating and reflecting the feedback and additional information we received through the multiple public comment opportunities the EPA made available on the 2016v2 modeling.

The EPA's development of and reliance on newer modeling is reasonable and is simply another iteration of the EPA's longstanding scientific and technical work to improve our understanding of air quality issues and causes going back many decades.

Comment: Commenters asserted that the EPA lacks authority under the good neighbor provision to do more than establish state-wide emissions budgets, which states may then implement through their own choice of emissions controls. The commenters claim that the EPA lacks authority to directly regulate emissions sources under the good neighbor provision, and they cite to case law that they view as establishing a ''federalism bar'' to direct Federal regulation. Commenters assert that the

[76] 87 FR 6095, 6097 at n. 15 (February 3, 2022) (Montana proposal); 87 FR 27050, 27056 (May 6, 2022) (Colorado, proposal), 87 FR 61249 (October 11, 2022) (Colorado, final).

[77] *See https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[78] *See https://www.epa.gov/scram/photochemical-modeling-applications.*

[79] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

term ''amounts'' as used in the good neighbor provision prevents the agency from establishing emissions limits at individual sources, such as the non-EGU industrial units that the EPA proposed to regulate or implementing ''enhancements'' in its mass-based emissions trading approach for EGUs as it had proposed. Commenters claim these aspects of the rule are an unlawful or arbitrary and capricious departure from the EPA's prior transport rulemakings, which they claim only set mass-based emissions budgets as the means to eliminate ''significant contribution.''

Response: To the extent these comments challenge the EPA's disapproval of states' 2015 ozone NAAQS good neighbor SIP submissions, they are out of scope of this action, which promulgates a FIP under the authority of CAA section 110(c)(1). To the extent commenters assert that the EPA does not have the authority to directly implement source-specific emissions control requirements or other emissions control measures, means, or techniques, including emissions trading programs, in the exercise of that FIP authority, the EPA disagrees. While the courts have long recognized that the states have wide discretion in the design of SIPs to attain and maintain the NAAQS, *see, e.g., Union Electric Co* v. *EPA,* 427 U.S. 246 (1976), when the EPA promulgates a FIP to cure a defective SIP, the Act, including the definition of a FIP in section 302(y), provides for the EPA to directly implement the Act's requirements. The EPA is granted authority to choose among a broad range of ''emission limitations or other control measures, means, or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances) . . . .'' CAA section 302(y); *see also* CAA section 110(a)(2) (empowering states to implement an identical set of emissions control mechanisms).

The courts have also recognized that the EPA has broad authority to cure a defective SIP, that the EPA may exercise its own, independent regulatory authority in implementing a FIP in accordance with the CAA, and that the EPA in effect steps into the shoes of a state when it promulgates a FIP. *See, e.g., Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531 (9th Cir. 1993); *South Terminal Corp.* v. *EPA,* 504 F.2d 646 (1st Cir. 1974). *Accord Virginia* v. *EPA,* 108 F.3d 1397, 1406–07 (D.C. Cir. 1997) (''The Federal Plan 'provides an additional incentive for state compliance because it rescinds state authority to make the many sensitive and policy choices that a pollution control regime demands.''') (quoting *Natural Resources Defense Council* v. *Browner,* 57 F.3d 1122, 1124 (D.C. Cir. 1995)). *Cf. District of Columbia* v. *Train,* 521 F.2d 971 (D.C. Cir. 1975), *vacated sub nom. EPA* v. *Brown,* 431 U.S. 99 (1977) (''[W]here cooperation [from states] is not forthcoming, we believe that the recourse contemplated by the commerce clause is direct federal regulation of the offending activity . . . .'').

These same principles apply where the EPA must promulgate a FIP to address good neighbor requirements under CAA section 110(a)(2)(D)(i)(I). The EPA has promulgated a series of FIPs in the past to address the relevant requirements for prior ozone and PM NAAQS. *See, e.g.,* CAIR FIP, 71 FR 25328 (April 28, 2006); CSAPR, 76 FR 48208 (August 8, 2011); the CSAPR Update, 81 FR 74504 (October 26, 2016); and the Revised CSAPR Update, 86 FR 23054 (April 30, 2021). Courts have upheld the EPA's exercise of this authority. *See EME Homer City Generation* v. *EPA,* 572 U.S. 489 (2014); *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019). Indeed, in *EME Homer City,* the U.S. Supreme Court held that the EPA is not obligated to provide guidance to states before acting on their good neighbor submissions or give states a second chance at correcting the deficiencies before promulgating a FIP, and the EPA may promulgate a FIP at any time after finalizing its disapproval of SIP submissions. 572 U.S. at 508–11.

The cases cited by commenters, which they refer to as establishing the *Train-Virginia* federalism bar, were not reviewing the exercise of the EPA's authority in promulgating a FIP under CAA section 110(c)(1) but rather were describing the scope of the EPA's authority in acting on SIP submissions under CAA section 110(k)(3) or in issuing a ''SIP call'' under section 110(k)(5). In those latter contexts, the courts have held that the EPA may not dictate the specific control measures states must implement to meet the Act's requirements. *See Virginia,* 108 F.3d at 1409–10. In *Michigan,* the D.C. Circuit upheld the EPA's exercise of CAA section 110(k)(5) authority in issuing the ''NO_X SIP Call,'' because, ''EPA does not tell the states how to achieve SIP compliance. Rather, EPA looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms. . . . However, EPA made clear that states do not have to adopt the control scheme that EPA assumed for budget-setting purposes.'' *Michigan* v. *EPA,* 213 F.3d 663, 687–88 (D.C. Cir. 2000).

Commenters' position that the EPA must provide similar flexibility to the states in this action (*i.e.,* only provide a general emissions reduction target and leave to states how to meet that target) is a non sequitur. The EPA is implementing a FIP in this action and *must* directly implement the necessary emissions controls. The EPA is not empowered to require states to implement FIP mandates. Such an approach would conflict with constitutional anti-commandeering principles, is not provided for in the Act, and would only constitute a partial implementation of FIP obligations in contravention of the holding in *Wisconsin* v. *EPA,* 938 F.3d at 313–20.

Commenters' attempt to contrast the implementation of source-specific emissions limitations at industrial sources with the establishment of a specific mass-based budget (as the EPA has set for power plants in prior good neighbor FIPs) is unavailing. CAA section 110(c)(1) and 302(y) authorize the EPA in promulgating a FIP to establish ''enforceable emission limitations'' in addition to other types of control measures like mass-based trading programs. Further, in this action, the EPA has developed an emissions control strategy that prohibits the ''amount'' of pollution that significantly contributes to nonattainment and/or interferes with maintenance. We determine that amount, as we have in prior transport actions, at Step 3 of the analysis, by applying a multifactor analysis that includes considering cost and downwind air quality effects. *See* section V.A of this document. With the implementation of the selected controls (at Step 4) through both an emissions trading program for power plants and source-specific emissions limitations for industrial sources, those ''amounts'' that had been emitted prior to imposition of the controls will be eliminated.

The Act does not mandate that the EPA must set a specific mass-based budget for each state to eliminate significant contribution based on the use of the term ''amounts'' in CAA section 110(a)(2)(D)(i). As the Supreme Court recognized, the statute ''*requires* States to eliminate those 'amounts' of pollution that 'contribute significantly to nonattainment' in downwind States,'' and it delegates to states or EPA acting in their stead discretion to determine *how* to apportion responsibility among those upwind states. 572 U.S. at 514 (emphasis added). The statute does not define the term ''amount'' in the way commenters suggest (or in any other way), and neither the Agency nor any court has reached that conclusion. The

Supreme Court itself has recognized that the language of the good neighbor provision is amenable to different types of metrics for quantification of ''significant contribution.'' *See EME Homer City Generation, L.P.,* 572 U.S. at 514 (''How is EPA to divide responsibility among the . . . States? Should the Agency allocate reductions proportionally . . ., on a per capita basis, on the basis of the cost of abatement, or by some other metric? . . . The Good Neighbor Provision does not answer that question for EPA.''); *see also Michigan* v. *EPA,* 213 F.3d 663, 677 D.C. Cir. 2000) (''Nothing in the text of . . . the statute spells out a criterion for classifying 'emissions activity' as 'significant.' ''); *id.* at 677 (''Must EPA simply pick some flat 'amount' of contribution . . . ?''). When the State of Delaware petitioned the Agency under CAA section 126(b) to establish daily emissions rates for EGUs to remedy what it saw as continuing violations of the good neighbor provision for the 2008 ozone NAAQS, neither the EPA nor the reviewing court questioned whether the Agency had the statutory authority to do so. The EPA's decision not to was upheld on record grounds. *See Maryland* v. *EPA,* 958 F.3d 1185, 1207 D.C. Cir. 2020) (''In other words, Delaware's concern makes sense but has not been observed in practice.'').[80]

The term ''amounts'' can be interpreted to refer to any number of metrics, and in fact the CAA uses the term in several contexts where it is clear Congress did not intend the term to refer to a fixed, mass-based quantity of emissions. For example, in the definition of ''lowest achievable emission rate'' (LAER) in CAA section 171, the Act provides that the application of LAER shall not permit a proposed new or modified source to emit any pollutant in excess of ''the amount allowable under applicable new source standards of performance [NSPS].'' NSPS may be, and usually are, set as emissions standards or limitations that are rate- or concentration-based. *See, e.g.,* 40 CFR part 60, subpart KKKK, table I (establishing concentration-based and rate-based emissions limits for stationary combustion turbines).[81] Congress has elsewhere used the term ''amount'' in the CAA to refer to concentration-based standards. For example, in CAA section 163(b), Congress provided that maximum allowable increases in concentrations of certain pollutants ''shall not exceed the following amounts,'' with a list of allowable increases provided that are expressed in micrograms per cubic meter.[82] As a third example, in the 1990 CAA Amendments, Congress provided that ozone nonattainment areas classified as Serious must provide a reasonable further progress demonstration of reductions in VOC emissions ''equal to the following amount,'' which is then described as a percentage reduction from baseline emissions. CAA section 182(c)(2)(B). These examples illustrate that the word ''amounts'' is amenable to a variety of meanings depending on what is being measured or quantified. It would therefore be highly unlikely that Congress could have intended that ''amount'' as used in the good neighbor provision must signify only a fixed mass budget of emissions for each state expressed as total tons per ozone season.

Such an approach would, in fact, fail to address an important aspect of the problem of interstate transport. As explained in sections III.B.1.d, V.D.4, and VI.B.1, the EPA in this rule seeks to better address the need for emissions reductions on each day of the ozone season, reflecting the daily, but unpredictably recurring, nature of the air pollution problem, short-term health impacts, and the form of the 2015 ozone NAAQS, wherein nonattainment for downwind areas (and thus heightened regulatory requirements) could be based on ozone exceedances on just a few days of the year. The expression of the ''amount'' of pollution that should be eliminated to address upwind states' ''significant contribution'' to that type of air pollution problem may appropriately take into account those aspects of the problem, and the EPA may appropriately conclude, as we do here, that a single, fixed, emissions budget covering an entire ozone season is not sufficient to the task at hand.

In this action, the EPA reasonably applies the good neighbor provision, including the term ''amount,'' through the 4-step interstate transport framework. Under this approach, the EPA here, as it has in prior transport rulemakings for regional pollutants like ozone, identifies a uniform level of emissions reduction that the covered sources in the linked upwind states can achieve that cost-effectively delivers improvement in air quality at downwind receptors on a regional scale. The ''amount'' of pollution that is identified for elimination at Step 3 of the framework is therefore that amount of emissions that is in excess of the emissions control strategies the EPA has deemed cost-effective. Contrary to commenters' views, in prior transport rules utilizing emissions trading, the mass budgets through which the elimination of significant contribution was effectuated did not constitute the ''amounts'' to be eliminated but rather the residual emissions remaining following the elimination of significant contribution through the control stringency selected based on our multifactor assessment at Step 3. Nor did the EPA consider a mass-based budget to be the sole expression, even indirectly, of what constituted ''significant contribution.'' *See, e.g.,* CSAPR, 76 FR 48256–57 (discussing the evaluation of the control strategies that would eliminate significant contribution for the 1997 ozone NAAQS, including combustion controls, and explaining, ''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).'').

In other actions the EPA has taken to implement good neighbor obligations, the EPA has required or allowed for reliance on source-specific emissions limitations rather than defining significant contribution as a mass-based budget. For example, the EPA imposed unit-specific emissions limitations in granting a CAA section 126(b) petition from the State of New Jersey in 2011. Final Response to Petition From New Jersey Regarding SO_2 Emissions From the Portland Generating Station, 76 FR 69052, 69063–64 (Nov. 7, 2011) (discussing the analytical basis for the establishment of emissions limits at specific units). This action was upheld by the Third Circuit in *Genon Rema LLC* v. *EPA,* 722 F.3d 513, 526 (3d. Cir. 2013).[83]

[80] The Agency's view of the basis for backstop daily emissions rates for certain EGUs within the trading program has changed since the time of its action on Delaware's petition, as explained in section VI.B.

[81] The EPA has interpreted the term ''amount'' as used in CAA section 111(a)(4) in the definition of the term ''modifications'' as an increase in a rate of emissions expressed as kilograms per hour. 40 CFR 60.14(b).

[82] Notably, both the provisions of CAA section 171 and section 163 given as examples here were added by the CAA Amendments of 1977, in the same set of amendments that Congress first strengthened the good neighbor provision and added the term ''amounts.'' *See* Public Law 95–95, 91 Stat. 685, 693, 732, 746.

[83] In CAA section 126(c), Congress provided for the EPA to directly impose ''emission limitations'' to eliminate prohibited significant contribution. Notably, the statute affords the EPA and states flexibility in how an ''emissions limitation'' may be expressed, including as a ''quantity, rate, or concentration,'' *see* CAA section 302(k). It would make little sense that the EPA could only establish a mass-based definition of ''amounts'' under CAA section 110(a)(2)(D)(i)(I), when the statute provides for rate- or concentration-based limitations in CAA section 126, which directly incorporates

Even where the EPA has provided for implementation of good neighbor requirements through mass-based budgets, it has recognized that other approaches may be acceptable as providing an equivalent degree of emissions reduction to eliminate significant contribution. *See, e.g.,* NO_X SIP Call, 63 FR 57378–79 (discussing approvability of rate-based emissions limit approaches for implementing NO_X SIP Call and providing, ''the 2007 overall budget is an important accounting tool. However, the State is not required to demonstrate that it has limited its total NO_X emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.''); CAIR, 70 FR 25261–62 (discussing ways states could implement CAIR obligations, including through emission-rate limitations, so long as adequately demonstrated to achieve comparable reductions to CAIR's emissions budgets).

Finally, as it has in its prior transport FIP actions, the EPA has in this action provided guidance for states on methods by which they could replace this FIP with SIPs, and in so doing, continues to recognize substantial state flexibility in achieving an equivalent degree of emissions reduction that would successfully eliminate significant contribution for the 2015 ozone NAAQS. *See* section VI.D of this document. While the EPA has exercised the responsibility it has under CAA section 110(c)(1) to step into the shoes of the covered states and directly implement good neighbor requirements through a particular set of regulatory mechanisms in this action, we anticipate that states may identify alternative, equivalent mechanisms that we would be bound to evaluate and approve if satisfactory, should states seek to replace this FIP with a SIP.

For these reasons, the EPA disagrees with the contention that it is constrained by the good neighbor provision to define upwind state obligations solely by reference to a fixed, mass budget. We find it reasonable in this action to again determine the amount of ''significant contribution'' at Step 3 by reference to uniform levels of cost-effective emissions controls that can be applied across the upwind sources. And, we find it appropriate to implement those emissions reductions at Step 4 through mechanisms that go beyond fixed, mass-based, ozone-season long budgets.

The EPA's authority for its industrial source control strategies is further discussed in sections II.C. and III.B.1.c of this document. The relationship of the control strategy to the assessment of overcontrol is discussed in section V.D.4 of this document. The relationship of our FIP authority to state authorities and SIP calls under CAA section 110(k)(5) is further discussed in *RTC* sections 1 and 2.

a. Step 1 Approach

As proposed, the EPA applies the same basic method of the CSAPR Update and the Revised CSAPR Update for identifying nonattainment and maintenance receptors. However, we received comments arguing that the outcome of applying our methodology to identify receptors in 2023 appears overly optimistic in light of current measured data from the network of ambient air quality monitors across the country. These commenters suggest that the EPA give greater weight to current measured data as part of the method for identifying projected receptors. As discussed further in section IV.D of this document, the EPA has modified its approach for identifying receptors for this final rule in response to these comments.

This concern is more evident given that the 2023 ozone season is just a few months away, and the most recent measured ozone values in many areas strongly suggest that these areas will not likely see the substantial reduction in ozone levels that the 2016v2 and 2016v3 modeling continue to project.

It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites. We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if our transport modeling projects that an area may reach attainment in 2023, we have other information indicating that there is an identified risk that attainment will not in fact be achieved in 2023. The EPA's analysis of these additional receptors further is explained in section IV.D of this document.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring promulgating a final FIP (and we have also deferred taking final action on that state's SIP submittal). This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

b. Step 2 Approach

The EPA applies 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 in these rules as needing further evaluation of their good neighbor obligations to downwind states at Step 3.[84] The EPA evaluated each state's contribution based on the average relative downwind impact calculated

110(a)(2)(D)(i)(I). (In observing this, we do not concede that an ''emissions limitation'' itself could not also be expressed through a mass-based approach, which may be read as authorized by the term ''quantity,'' a term also used in CAA section 302(k).)

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

over multiple days.[85] States whose air quality impacts to all downwind receptors were below this threshold did not require further evaluation for measures 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 relatively low contribution screening threshold because many downwind ozone nonattainment and maintenance receptors receive transport contributions from multiple 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 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 final rule, the EPA has updated the air quality modeling data used for determining contributions at Step 2 of the 4-step interstate transport framework using the 2016v3 modeling platform. The EPA continues to find that this threshold is appropriate to apply for the 2015 ozone NAAQS. This rule's application of the Step 2 approach is comprehensively described in section IV of this document.

Many commenters challenged the use of a 1 percent of NAAQS threshold or otherwise raised issues with the EPA's Step 2 methodology. These comments are addressed in section IV.F of this document and in the *RTC* document.

[85] The number of days used in calculating the average contribution metric has historically been determined in a manner that is generally consistent with the 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, the 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*).

c. Step 3 Approach

The EPA continues to apply the same approach as the prior three CSAPR rulemakings for evaluating ''significant contribution'' at Step 3.[86] For states that are linked at Step 2 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*.[87]

In this action, the EPA applies 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. The 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 finalizes 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 finalizes 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 commensurate with the control strategy for EGUs.

[86] For simplicity, the EPA (and courts) at times will refer to the Step 3 analysis as determining ''significant contribution''; however, the 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.''). *See also EME Homer City,* 795 F.3d 118, 136 (upholding this approach to prong 2).

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

In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the 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 the 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 rule, the 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 finds 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 rule requires 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 V of this document.

In this 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 omitted).

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 74551–52. *See also Wisconsin,* 938 F.3d at 325 (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 rule, and, as discussed in section V.D.4 of this document, does not find any over-control at the final control stringency selected.

This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of whether there is proven over-control, results in the 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.

Comment: Commenters alleged that the EPA lacks authority to regulate EGUs under the good neighbor provision of the CAA, or at least in the manner proposed, because in their view, this regulation would intrude into areas of regulation that are reserved to other Federal agencies or are beyond the EPA's expertise. They focused in particular on the EGU trading program enhancements, which they alleged would threaten electric grid reliability, and asserted that EPA lacks authority or expertise to dictate the mix of electricity generation in the country.

Response: The EPA disagrees that the regulation of EGUs in this action is unlawful or unsupported. The Agency has consistently and successfully regulated EGUs' ozone season NO_X emissions under the good neighbor provision for over 25 years, beginning with the 1997 NO_X SIP Call. This action does not intrude on other Federal agencies' authorities and responsibilities with respect to managing the electric power grid and ensuring reliable electricity. While other agencies such as the Federal Energy Regulatory Commission (FERC) have primary responsibility for ensuring reliability of the bulk electric system, the EPA has ensured that its final rule here will not create electric reliability concerns. See section VI.B.1.d of this document. Thus, to the extent commenters are raising a record-based issue that the EPA through this action has created a reliability concern, we disagree. The EPA engaged in a series of stakeholder meetings with Reliability Coordinators who commented on the proposed rule, including several Regional Transmission Organizations (RTOs) as well as non-RTO entities throughout the rulemaking process.[88]

To the extent commenters maintain that—despite this record of collaboration and sensitivity to the need to ensure reliability in the implementation of its mandates, including in this rule—the EPA nonetheless fundamentally lacks authority to regulate the electric-power sector in any way that ''impact[s] national electricity and energy markets,'' the EPA disagrees. The EPA has successfully regulated interstate ozone-precursor emissions from the power sector since the NO_X SIP Call and the establishment of the NO_X Budget Trading Program. *See generally Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000); *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032 (D.C. Cir. 2001). In fact, each of the EPA's interstate ozone transport rulemakings has focused on the regulation of ozone-precursor emissions from the power sector (all but the NO_X SIP Call exclusively), because substantial, cost-effective reductions in ozone-precursor emissions have been and continue to be available from fossil-fuel fired EGUs. *See, e.g.,* 63 FR 57399–400 (NO_X SIP Call); 70 FR 25165 and 71 FR 25343 (CAIR and CAIR FIP); 76 FR 48210–11 (CSAPR); 81 FR 74507 (CSAPR Update); 86 FR 23061 (Revised CSAPR Update).[89]

This rule, like all prior EPA ozone-transport rulemakings, regulates only one aspect of the operation of fossil-fuel fired EGUs, that is, the emissions of NO_X as an ozone-precursor pollutant during the ozone season. This rule limits EGU NO_X emissions that interfere with downwind states' ability to attain and maintain the 2015 ozone NAAQS. The rule does not regulate any other aspect of energy generation, distribution, or sale. For these reasons, the rule does not intrude on FERC's power under the Federal Power Act, 16 U.S.C. 791a, *et seq.* And, as in prior transport rules, the EPA implements this regulation through a proven, flexible mass-based emissions trading program that integrates well with, and in no way intrudes upon, the management of the power sector under other state and Federal authorities. This rule will not alter the procedures system operators employ to dispatch resources or force changes to FERC-jurisdictional electricity markets, nor have commenters offered any explanation in this regard themselves.

The actual compliance requirement that the EGUs must meet in the allowance trading system finalized here—just as in all prior interstate transport trading programs—is simply to hold sufficient allowances to cover emissions during a given control period, not to undertake any specific

[88] See Documents no. EPA–HQ–OAR–2021–0668–0938, EPA–HQ–OAR–2021–0668–0940, EPA–HQ–OAR–2021–0668–0941, EPA–HQ–OAR–2021–0668–0942, EPA–HQ–OAR–2021–0668–0943, EPA–HQ–OAR–2021–0668–0944, and EPA–HQ–OAR–2021–0668–0945 in the docket for this rulemaking.

[89] There are myriad other examples of effective power sector regulation under the CAA and other environmental statutes, including for example, new source performance standards (NSPS), best available retrofit technology (BART) requirements, and mercury and air toxics standards (MATS) under the CAA; effluent limitation guidelines (ELGs) under the Clean Water Act; and coal combustion residuals (CCR) requirements under the Resource Conservation and Recovery Act. Whether implemented through unit- or facility-level pollution control requirements or through emissions-trading or other market-based programs, these regulations have been effective in reducing air and water pollution while not intruding into the regulatory arenas of other state and Federal entities. *See* Section 1 of the *RTC* for further discussion.

compliance strategy.[90] The owner or operator of an EGU has flexibility in determining how it will meet this requirement, whether through the add-on emissions controls that the EPA has selected in our Step 3 analysis, or through some other method or methods of compliance. The costs of meeting this allowance-holding requirement—just like the cost associated with meeting any other regulatory requirements—could possibly then be factored into what that unit bids in the wholesale electricity market (or in regulated jurisdictions, would factor into utility regulators' determinations of what can be cost-recovered).

Those costs could, in turn, result in a reduction in electricity generation from higher-emitting sources and an increase in electricity generation from lower-emitting or zero-emitting generators, but that kind of generation shifting (not mandated but occurring as an economic choice by the regulated sources) is consistent, and in no way interferes with, the existing security-constrained economic dispatch protocols of the modern electrical grid. Further, this type of ''impact'' on electricity markets—merely incidental, not mandated or even intended—is of the same type that results from any other kind of regulation, environmental or otherwise. Indeed, the U.S. Supreme Court recognizes that regulatory actions that may have some ''effect,'' or impact, in electricity markets do not on that basis alone intrude into authorities reserved to electricity rate-setting regulators by the Federal Power Act. *See FERC* v. *Electric Power Supply Ass'n,* 577 U.S. 260, 282–84 (2016) (distinguishing between actions that have an effect on retail rates and actual intrusion into retail rate-setting itself); *see also Hughes* v. *Talen,* 578 U.S. 150, 166 (2016). The Supreme Court again recognized this distinction between ''incidental'' effects caused by lawfully issued environmental regulations and attempts to mandate a particular energy mix in *West Virginia* v. *EPA. See* 142 S. Ct. 2587, 2613 n.4 (2022) (''[T]here is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be . . . .'').

This rule is squarely in the former camp; as the most stringent component of its emissions controls strategy for EGUs, the EPA has determined that to eliminate significant contribution to harmful levels of ozone in other states, certain fossil-fuel fired EGUs in ''linked'' upwind states that do not already have selective catalytic reduction (SCR) post-combustion control technology, should install it (or achieve emissions reductions commensurate with that technology). SCR is a well-established at-the-source NO_X control technology already in use by EGUs representing roughly 60 percent of the existing coal-fired generating capacity in the United States. This technology can be installed and operated to reduce NO_X emissions without forcing the retirement or reduced utilization of any EGU. However, if market conditions are such that an EGU faced with this mandate (again, as expressed through an emissions trading budget) finds it more economic to comply with the mandate through the purchase of allowances, installation of other types of pollution control, reduced utilization, and/or retirement, rather than installing SCR technology, that is a choice that the EGU owner/operator can freely make under this rule.[91] Security constrained economic dispatch is thereby maintained and is in no way interfered with.

The EPA recognizes that cost to operate generators is one of the major factors that system operators utilize to determine ''merit'' order in dispatching resources. However, this rule does not intrude in any way into that process. To the extent that compliance with environmental regulations is a kind of cost that may need to be factored into generators' bids, this rule is no different than many other such requirements EGUs are already subject to. Further, as in prior transport rules, this rule applies a uniform control stringency to EGUs within the covered upwind states. EGUs that may have enjoyed a competitive advantage in the past through not bearing the costs of installing and running state-of-the-art emissions control technology now must bear that cost just as their competitors with that technology already are. *Cf. EME Homer City,* 572 U.S. 489, 519 (CSAPR is ''[e]quitable 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.'').

Finally, we note that this final rule does not include ''generation shifting'' as a component of the budget-setting process, even in the limited way that it had been used in prior transport rules like CSAPR and the CSAPR Update, *i.e.,* to ensure the budget provided adequate incentive to ensure implementation of the selected emission-control strategy. *See* section V.B.1.f of this document. Further comments regarding legal authority for ''generation shifting,'' relationship to state authorities, and expertise associated with grid reliability are addressed in section 1.3 of the *RTC.* We further discuss our consideration of grid reliability concerns and adjustments in the approach to the EGU emissions trading program from proposal in section VI.B.1.d of this document.

Comment: Commenters generally challenged the EPA's authority to establish emissions control requirements for non-EGU industrial sources in this action, or argued that such controls are unnecessary or unsupported, or run contrary to the EPA's prior actions under the good neighbor provision.

Response: The states and the EPA have authority under CAA section 110(a)(2)(D)(i)(I) to prohibit emissions from ''any source or other type of emissions activity'' that are found to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states. This language is not limited only to power plant emissions, nor is it limited only to ''major'' sources or ''stationary'' sources. Thus, as a legal

[90] The EPA has included in this trading program certain ''enhancements'' to ensure that the program continues to eliminate the emissions the EPA has determined constitute ''significant contribution'' over the entire life of the trading program. While one of the enhancements elevates a type of conduct that was already strongly discouraged into an enforceable violation, the other enhancements all simply modify the traditional allowance-based program structure to revise how the specific quantities of allowances that must be surrendered or the specific quantities of allowances available for surrender are determined. In finalizing this rule, the EPA has made a number of changes to its proposed enhancements to the trading program in response to comment and in part to ensure no impact on system reliability. Nonetheless, with these changes, the EPA has determined that the enhanced trading program can be implemented without impacting grid reliability. See section VI.B.1.d of this document.

[91] As explained in section V.B of this document, the imposition of a backstop emissions rate beginning in 2030 for units that do not already have SCR installed could lead the owner of a given unit to decide that the unit's continued operation would be uneconomic without installation of SCR, but the establishment of technology-based emissions rates that require such decisions is consistent with decades of the EPA's rulemaking and permitting actions requiring source-specific pollution controls. Further, the backstop rate in this program is implemented through an enhanced allowance-surrender ratio, thus preserving some degree of flexibility through the emissions-trading program as the mechanism of compliance.

matter, the emissions control requirements for certain large ''non-EGU'' industrial sources in this action are grounded in unambiguous statutory authority, in particular the statute's use of the broad term ''any source.'' Whereas the Act elsewhere includes definitions of ''major stationary source,'' ''small source,'' and ''stationary source,'' *see, e.g.,* CAA section 302(j), (x), and (z), no such qualifying terms are used with respect to the term ''any source'' at CAA section 110(a)(2)(D)(i). Rather, the scope of authority in this provision expands to encompass ''other type of emissions activity'' in addition to ''any source.'' The EPA has previously included non-EGU industrial sources in findings quantifying states' obligations under the good neighbor provision, in the 1998 NO_X SIP Call, *see* 63 FR 57365.[92] *See also Michigan* v. *EPA,* 213 F.3d 663, 690–93 (upholding the inclusion of certain non-EGU boilers in the NO_X SIP Call). The EPA's determinations in prior transport rules not to regulate sources beyond the power sector were grounded in considerations not related to the Agency's statutory authority. For example, in the original CSAPR rulemaking, the EPA determined that the analytical effort needed to regulate non-EGU industrial sources would substantially delay the implementation of emissions reductions from the power sector. *See, e.g.,* 76 FR 48247–48 (''[D]eveloping the additional information needed to consider NO_X emissions from non-EGU source categories to fully quantify upwind state responsibility with respect to the 1997 ozone NAAQS would substantially delay promulgation of the Transport Rule. . . . [W]e do not believe that effort should delay the emissions reductions and large health benefits this final rule will deliver[.]''). The EPA acknowledged that by not addressing non-EGUs, it may not have promulgated a complete remedy to good neighbor obligations in CSAPR, *id.* at 48248. Nonetheless, the EPA went on to explain that there were limited emissions reductions available from non-EGUs at the cost thresholds the EPA determined would deliver substantial reductions from power plants. *See id.* at 48249 (the EPA's ''preliminary assessment in the rule proposal suggested that there likely would be very large emissions reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions . . . . EPA revisited these non-EGU reduction cost levels in this final rulemaking and verified that there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen . . . .''). The EPA noted in CSAPR that states retained the authority to regulate non-EGUs as a method of addressing their good neighbor obligations. *Id.* at 48320. The EPA also noted in CSAPR that ''potentially substantial'' non-EGU emissions reductions could be available in future rulemakings applying a higher cost threshold. *See id.* at 48256.

Similarly, in the CSAPR Update, which addressed good neighbor obligations for the 2008 ozone NAAQS, the EPA found that regulation of non-EGUs was not warranted as the analysis required could delay the expeditious implementation of power plant reductions. The EPA found that the availability and cost-effectiveness of non-EGU reductions was uncertain and further analysis could delay implementation of the EGU strategy beyond 2017. The EPA acknowledged that it was not promulgating a complete remedy for good neighbor obligations for the 2008 ozone NAAQS and indicated its intention to further review emissions-reduction opportunities from non-EGU and EGU sources. 81 FR 74521–22.

In *Wisconsin,* the court held that the EPA's deferral of a complete good neighbor remedy by 2017, on the basis, among other things, of uncertainty regarding non-EGU emissions reductions and the need for further regulatory analysis, was unlawful. 938 F.3d at 318–19. The court noted that '' 'the statutes and common sense demand regulatory action to prevent harm, even if the regulator is less than certain.' '' *Id.* at 319 (quoting *Ethyl Corp.* v. *EPA,* 541 F.2d 1, 24–25 (D.C. Cir. 1976)), and that agencies can only avoid meeting their statutory obligations where ''scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment.'' *Id.* (citing *Massachusetts* v. *EPA,* 549 U.S. 497, 534 (2007)). Further, the court rejected the EPA's argument that it would have delayed its rulemaking if the EPA needed to complete a non-EGU analysis in a timely manner, holding that ''administrative infeasibility'' is not sufficient to ''justify . . . noncompliance with the statute.'' *Id.* Rather, the Agency would need to ''meet the 'heavy burden to demonstrate the existence of an impossibility.' '' *Id.* (quoting *Sierra Club* v. *EPA,* 719 F.2d 436, 462 (D.C. Cir. 1983)).

Following the remand of the CSAPR Update in *Wisconsin,* in the Revised CSAPR Update, the EPA conducted an analysis of non-EGUs to ensure it had implemented a complete remedy to eliminate significant contribution for the covered states for the 2008 ozone NAAQS. While acknowledging uncertainty in the datasets for non-EGUs, the EPA concluded: ''[U]sing the best information currently available to the Agency, . . . the EPA is concluding that there are relatively fewer emissions reductions available at a cost threshold comparable to the cost threshold selected for EGUs. In the EPA's reasoned judgment, the Agency concludes such reductions are estimated to have a much smaller effect on any downwind receptor in the year by which the EPA finds such controls could be installed.'' 86 FR 23059. Therefore, the EPA determined control of non-EGU emissions was not required to eliminate significant contribution for the 2008 ozone NAAQS.

The circumstances that led the EPA to defer or decline regulation of non-EGU sources in CSAPR, the CSAPR Update, and the Revised CSAPR Update, are not present here, and the EPA's determination in this action that prohibiting certain emissions from certain non-EGU sources is necessary to eliminate significant contribution for the 2015 ozone NAAQS is a logical extension of the analyses and evolution of regulatory policy development spanning its prior good neighbor rules, now applied to implement this more protective NAAQS. As the EPA explained at proposal, unlike in CSAPR and the Revised CSAPR Update, in this action the EPA finds that available reductions and cost-levels for the non-EGU stringency are commensurate with the control strategy for EGUs. Following consideration of comments and after some adjustments in the non-EGU analysis and control strategy, in this final rule, the EPA continues to find this to be the case. *See* sections V.C and V.D of this document.

In particular, the EPA continues to find that cost-effective emissions reductions are available for non-EGUs at a representative cost-threshold that is lower than the cost-threshold the EPA is applying for EGUs. *See* section V.C. of this document. These emissions control strategies are generally comparable to the emissions reduction requirements that similar sources in downwind states

[92] Specifically, in the NO_X SIP Call, the EPA set statewide budgets while states could determine which sectors to regulate. The EPA recommended that states regulate certain types of non-EGUs and quantified the statewide budgets based in part on the emissions reductions from those types of non-EGUs. In the parallel rule that followed under the EPA's CAA section 126(b) authority to directly regulate emissions to eliminate significant contribution, we promulgated an emissions trading program that would have included these same types of non-EGUs. Before this rule was implemented, all states adopted equivalent state trading programs using the NO_X SIP Call model rule.

are already required to meet. *See* section V.B.2 of this document. The EPA finds that the implementation of these emissions control strategies at non-EGUs, in conjunction with the strategies for EGU, will make a cost-effective and meaningful improvement in air quality through reducing ozone levels at the identified downwind receptors, and, therefore, the EPA has determined that these strategies will eliminate the amount of upwind emissions needed to address significant contribution under the good neighbor provision. The EPA's action here is focused on the most impactful industries and emissions units as determined by our evaluation of the power sector and the non-EGU screening assessment prepared for the proposal; indeed, of the 41 industries, as identified by North American Industry Classification System codes, we analyzed, only nine industries met the criteria for further evaluation of significant contribution. *See* section V.B.2 of this document. Further, the EPA finds that these strategies do not result in ''overcontrol.'' *See* section V.D.4 of this document. As such, the EPA maintains that its final determinations regarding non-EGUs and its inclusion of non-EGU emissions sources within this final rule are statutorily authorized and lawful.[93]

The EPA disagrees that it should defer regulation of industrial sources to the NSPS program under CAA section 111(b). CAA section 111(b) does not expressly provide for the elimination of ''significant contribution'' as is required under CAA section 110(a)(2)(D)(i)(I). In particular, commenter's statement that NSPS rulemakings under section 111(b) will appropriately address the emissions that we find must be eliminated in this action is not correct. Standards under section 111(b) apply only to new and modified sources, not existing sources. This action, however, finds that reductions in ongoing emissions from existing sources are needed to eliminate significant contribution. An NSPS standard for new and modified sources would not address such emissions from existing sources. To the extent that covered sources in this action also may be covered by an older NSPS, these sources nonetheless continue to have emissions that the EPA finds significantly contribute and can be eliminated through further emissions control as determined in this action. We further disagree with commenter's separate suggestion that the EPA use section 111(b) and (d) to regulate both new and existing sources of ozone season NO_X, which is premised on the incorrect notion that the EPA's action here is an attempt to regulate entire source categories nationwide, rather than to eliminate significant contribution pursuant to CAA section 110(a)(2)(D)(i)(I). This action applies only to the extent a state is ''linked'' to downwind receptors, and therefore this action only regulates covered non-EGU industrial sources in 20 states. Further, this comment ignores that the regulation of criteria pollutant emissions from existing sources under CAA section 111(d) is limited by the criteria pollutant exclusion in CAA section 111(d)(1)(A)(i).

The EPA agrees with the commenters who assert that the EPA's authority to regulate non-EGUs under the good neighbor provision is well-grounded in administrative precedent and case law. Our previous discussion briefly recites several of the most salient aspects of that history. We also agree that the statutory language is not limited only to those sources that emit above 100 tons per year. The EPA's Step 3 and Step 4 analyses in this regard, which establish certain thresholds based on historical actual emissions, potential to emit and/or metrics for unit design capacity, reflect a reasoned judgment by the Agency regarding which emissions can be cost-effectively eliminated to address significant contribution, under the facts and circumstances of this action. That these thresholds are designed to exclude certain smaller or lower-emitting units does not reflect a determination that the EPA lacks legal authority to regulate such sources under different facts and circumstances.

The EPA identified two industry tiers of potential non-EGU emissions reductions in its non-EGU screening assessment at proposal, based on screening metrics intended to capture different kinds of impacts that non-EGU sources may have on identified receptors. The EPA agrees that it is only authorized to prohibit emissions under the good neighbor provision that significantly contribute to nonattainment or interfere with maintenance in downwind states, and we determined that these industries did so. The EPA sought comment on whether additional non-EGU industries significantly contributed to nonattainment or interfered with maintenance in downwind states. The EPA did not receive comments identifying other industrial stationary sources that are more impactful that should be regulated instead of those the EPA identified. We believed at proposal and confirm here in our final rule that the methodology used in the screening assessment comported with the factors that we consider at Step 3. Further, the EPA's 4-step interstate transport framework, including the Step 3 analysis and an overcontrol assessment, ensure that the emissions reductions achieved at each source covered by this rule are in fact justified as part of an overall, complete remedy to eliminate significant contribution for the covered states for the 2015 ozone NAAQS. The EPA has decided to finalize emissions limitations for all of the non-EGU industries, with some modifications from proposal reflecting public input, as discussed in section VI.C of this document. The Agency's authority to establish unit- and/or source-specific emissions limitations in exercising our FIP authority is further discussed in section III.B.1 of this document.

Comment: Commenters raise additional issues with the overall approach of the rule at Step 3 to address significant contribution through our evaluation of EGU and non-EGU strategies through parallel but separate analyses. They stated that the EPA failed to establish that the identified non-EGU emissions reductions are needed to eliminate significant contribution. Commenters stated that the identified non-EGU emissions reductions are not impactful of air quality at receptors or that they are much less cost-effective than the EGU emissions reductions. Commenters stated that the EPA grouped all non-EGU emissions reductions together in making a cost-effectiveness determination that is only an average and ignores significant variation in costs associated with controls on different types of non-EGU emissions units. They also stated the EPA did not assess multiple control technologies in the way that it did for EGUs, and they argued there is great variation in the profile of non-EGU industries and emissions unit types in the different upwind states or that individual emissions units do not contribute to an out-of-state air quality problem at all. Commenters argued that certain non-EGU controls were not feasible, or that the EPA had applied a different standard for ''feasibility'' for non-EGUs than it did for EGUs. Commenters stated that the EPA should have provided a mass-based trading option for non-EGUs just as it had for EGUs. By contrast, other commenters supported the regulation of non-EGUs in this action as necessary to ensure a complete remedy to good neighbor obligations, since the statute is not limited to regulating power plants.

[93] Certain changes in the emissions control strategies for non-EGUs reflecting comments and updated information are explained in section VI.C of this document.

Some commenters further stated that EGUs should not face any further emissions reduction obligation because all cost-effective controls have already been identified through prior transport rules, and that any further regulation of EGUs would only lead to the retirement of coal plants, which they believe is the EPA's true objective. Finally, some commenters argued that the EPA had not ensured that it only regulated up to the minimum needed for downwind areas to come into attainment.

Response: Issues related to the specific technical bases for the Agency's determinations of what emissions constitute ''significant contribution'' at Step 3 of the 4-step framework are addressed in section V of this document. Here, we evaluate commenters' more general assertions that this action addresses non-EGU or EGU emissions in an inconsistent way. First, the EPA agrees with commenters that the task of evaluating significant contribution from the non-EGU industries is complex compared to EGUs in light of the much greater diversity in industries and emissions unit types. This, however, is not a valid basis to avoid emissions control requirements on such sources if needed to eliminate significant contribution. In this respect, the EPA's analysis in this final rule is that the 4-step framework, as upheld by the Supreme Court in *EME Homer City,* can be adequately applied even to this more complex set of sources in a way that parallels the analysis previously conducted only for EGUs. This analysis relies on evaluation of uniform levels of control stringency across all upwind states to find a level of emissions control that is cost-effective and collectively delivers meaningful downwind air quality improvement. For non-EGUs, the EPA identified the most impactful industries and emissions unit types and evaluated emissions control strategies for these units that have been demonstrated or applied across many similar facilities and emissions units. The EPA has evaluated whether these strategies are cost-effective on a cost-per-ton basis, and in particular has compared these strategies to those selected for EGUs. This analysis is set forth in sections V and VI of this document and associated technical support documents.

Commenter's statement that the establishment of a uniform level of control for each group of industrial units across the linked upwind states fails to assess with greater precision or define a state-specific proportion of emissions reduction that is needed for each downwind receptor is effectively an attempt to relitigate *EME Homer City.* The Court in that case rejected that the EPA must define significant contribution by reference to a specific quantum of reductions that each state must achieve that is proportional to its impact at a downwind receptor. The Court agreed with the EPA's concerns as to why that approach would be problematically complicated or even impossible to apply in light of the complex set of linkages among states for a regional pollutant like ozone. *See* 572 U.S. at 515–17. The Court found that the use of uniform cost thresholds to allocate responsibility for good neighbor obligations to be efficient and equitable, in that it requires those sources that have done less to reduce their emissions to come up to a minimum level of performance to what other sources are already achieving. *Id.* at 519. The EPA's analysis in this action in section V of this document establishes that this continues to be an appropriate means of delivering meaningful air quality improvement to downwind receptors, taking into consideration the complexities of interstate pollution transport.

Not every upwind state has the same mix of non-EGU industries and emissions unit types, and it is also the case that the costs for installation of the selected level of control technology will vary from facility to facility based on site-specific considerations. This is also true for the set of EGU sources regulated here and in previous CSAPR rulemakings. These real-world complexities do not obviate the broader policy and technical judgements that the EPA makes at Step 3 regarding what level of emissions control performance can be achieved on a region-wide basis to resolve significant contribution for a regional-scale pollutant like ozone. The EPA's design of cost thresholds derives from the identification of discrete types of NO_X emissions control strategies. The EPA then identifies a representative cost-effectiveness on a per ton basis for that technology. In the Step 3 analysis, it is not the cost per ton value itself that is inherently meaningful, but rather how that cost-effectiveness value relates to other control stringencies, how many emissions reductions may be obtained, and how air quality is ultimately impacted. The selected level of control stringency reflects a point at which further emissions mitigation strategies become excessively costly on a per-ton basis while also delivering far fewer additional emissions reductions and air quality benefits. This is often referred to as a ''knee in the curve'' analysis. There are always inherent uncertainties in identifying a representative cost per ton value for any particular control stringency, but this in itself does not upset the EPA's ability to render an overall policy judgment based on the Step 3 factors as to a set of emissions control strategies that together eliminate significant contribution. *See* 86 FR 23054, 23073 (responding to similar comments on the Revised CSAPR Update).

We note that the EPA has made a number of adjustments to the non-EGU emissions limits identified at Step 4 to accommodate legitimate concerns regarding the ability of certain non-EGU facilities to meet the emissions control requirements that the EPA had proposed. The Agency's determinations regarding feasibility and installation timing for pollution controls are comparable and not inconsistent between EGUs and non-EGUs. The EPA is not establishing a trading program for non-EGUs because the Agency does not have adequate baseline emissions data and information on monitoring currently at many of these emissions units to develop emissions budgets that could reliably implement the Step 3 determinations made in this action. However, for most of the non-EGU industries,[94] the EPA is not mandating a specific control technology and is instead establishing numeric emissions limits that are uniform across the region and that allow sources to choose how to comply. The EPA's analysis, including review of RACT determinations, consent decrees, and permitting actions, shows that these emissions limits and control requirements are achievable by existing units in the non-EGU industries covered by this final rule. This rule will therefore bring all of these impactful industries and unit types across the region of linked upwind states up to this standard of performance, and thus will result collectively in a relatively substantial decrease in ozone-season NO_X emissions, with associated reductions in ozone levels projected to result at the downwind receptors. This is further discussed in section V.D.

Some commenters alleged that the EPA's EGU control strategy goes beyond the cost-effectiveness determinations of prior transport rules, and they believe that the EPA's true objective is to force the retirement of coal plants. First, we note that the EGU emissions control strategy is premised entirely on at-the-

[94] For reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing industry, the EPA is establishing requirements to operate low-NO_X burners achieving a specified level of emissions reduction; this approach is needed to allow for unit-specific testing before an appropriate emissions limitation can be set. *See* section VI.C.3 of this document.

source emissions control technologies that are widely available and in use across the EGU fleet. It is not the EPA's intention in this rule to force the retirement of any EGU or non-EGU facilities or emissions units but to identify and eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I) based on cost-effective and proven control technologies that are appropriate in relation to address the problem of interstate transport for the 2015 ozone NAAQS. Further, determinations of cost-effectiveness must be made in relation to the particular statutory provision and its purpose. The EPA recognized in CSAPR, for example, that additional emissions reductions beyond what were determined to be cost-effective in that action could be required to implement good neighbor obligations if a NAAQS were revised to a more protective level. *See* 76 FR 48210. Here it is not surprising that a more stringent level of control could be found justified in implementing transport obligations for the more protective 2015 ozone NAAQS. Those reductions are projected to deliver meaningful air quality improvement to downwind receptors, as discussed in section V.D of this document. Those air quality benefits continue to compare favorably to the air quality benefits that will be delivered through the combined non-EGU emissions limits, which apply to nine non-EGU industries (see section V.C of this document). We find that the implementation of both the EGU and non-EGU strategies identified in section V of this document together represent the appropriate level of emissions control stringency to eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I).

Finally, the EPA also analyzed for overcontrol and does not identify any. Some commenters misstate the purpose of this rule as bringing downwind receptors into attainment. In line with the statutory directive in CAA section 110(a)(2)(D)(i)(I), this rule eliminates ''significant contribution'' from upwind states; while the rule has substantial air quality benefits for downwind receptors, in many cases we project that a nonattainment or maintenance problem will continue to persist through 2023 and 2026 despite the emissions reductions achieved by this rule. Commenters alleging overcontrol have not met the requirement that overcontrol be established by particularized evidence through as-applied challenges. The Supreme Court has recognized that the EPA also has an obligation to avoid under-control and must have some leeway in fulfilling the good neighbor mandate of the Act given uncertainty in making forward projections of air quality and the efficacy or impact of emissions control determinations. *See EME Homer City,* 572 U.S. at 523. This is further addressed in section V.D.4 of this document.

d. Step 4 Approach

The EPA is finalizing an approach similar to its prior transport rulemakings to implement the necessary emissions reductions through permanent and enforceable measures. The EPA is requiring EGU sources to participate in an emissions trading program and is making 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 is finalizing permanent and enforceable emissions rate limits and work practice standards, and associated compliance requirements, for several types of NO_X-emitting combustion units across several industrial sectors. The measures for both EGUs and non-EGUs are required throughout the May 1-September 30 ozone season of each year. The EGU program will begin with the 2023 ozone season, and the non-EGU implementation schedule is targeted to the 2026 ozone season. Refer to section VI.A of this document for details on the implementation schedule.

Based on the EPA's experience in implementing prior transport rulemakings, the Agency is making 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 in each control period 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 the 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, the EPA is retaining an interstate trading program approach while making several enhancements to that approach.

Thus, in this rulemaking, the EPA is including dynamic budget-setting procedures in the regulations that will allow state emissions budgets for control periods in 2026 and later years to reflect more current data on the composition and utilization of the EGU fleet (*e.g.,* the 2026 budgets will reflect recent data through 2024 data, the 2027 budgets will reflect data through 2025, etc.). These enhancements will 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 emissions controls in the latter years of the program. To provide greater certainty regarding the minimum quantities of allowances that will be available for compliance for the control periods in 2026 through 2029, the EPA is also establishing preset state emissions budgets for these control periods, and a dynamic state emissions budget determined for one of these control periods will apply only if it is higher than the state's preset budget for the control period.

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 in power sector emissions to account for fluctuations in demand and EGU operations and is responsive to previous court decisions (see discussion in section VI.B.5 of this document). In this action, the EPA is maintaining the existing assurance provisions that limit state emissions to levels below a percentage of the state's budget by requiring additional allowance surrenders in any instance where emissions in the state exceed the specified level, but with adjustments that allow the level to exceed 121 percent of a state's budget in a given control period if necessary to account for actual operational conditions in that control period. In addition, the EPA is also making 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 certain units that contribute to exceedances of the assurance levels, to ensure EGU emissions control operation and associated air quality improvements. Implementation of the EGU emissions reductions using a CSAPR NO_X trading program is further described in section VI.B of this document.

In this rule, the EPA is also establishing emissions limitations for the non-EGU industry sources listed in Table II.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 finds that requiring NO_X emissions reductions through emissions rate limits and control technology requirements for certain non-EGU industrial sources that the EPA found at Step 3 to be relatively impactful[95] on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA is establishing 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 transport provision for the 2015 ozone NAAQS.

Finally, the EPA finds 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 final rule. This is consistent with the 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 has 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). The EPA's approach of including new units in the NO_X Budget Trading Program promulgated under the EPA's CAA section 126 authority was upheld by the D.C. Circuit in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (2001). As the court noted, 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 is implementing the same court-affirmed 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.

Comment: Commenters took issue with aspects of the EPA's proposed Step 4 approach. Commenters argued the EPA could not set unit- or source-specific emissions limits or other control requirements, for EGUs or non-EGUs. Commenters argued that various aspects of the non-EGU emissions control strategy would not be feasible for their facilities or were otherwise flawed. Many industrial-source and EGU commenters argued that the EPA had not provided sufficient time for sources to come into compliance. Commenters also challenged the EGU trading program ''enhancements'' as unnecessary or beyond the EPA's authority. In this regard, commenters argued that these changes deviated from the EPA's prior approach, were unnecessary overcontrol, constituted a command-and-control approach, could not be supported on the basis of environmental justice benefits, or were otherwise unlawful for other reasons. These commenters argue that the EPA's Step 4 dynamic budget approach for EGU regulation purportedly re-defines each state's ''significant contribution'' annually and independent of any impact (or lack thereof) on air quality. They further argue that under this dynamic budgeting approach, even if a state eliminates the ''amount'' the EPA has identified as the state's significant contribution by respecting a given control period's emissions budget, sources within that state are expected to continue to make further reductions by operating their controls in a particular manner in subsequent control periods under potentially lower emissions budgets, which these commenters argue is inconsistent with case law on prior CSAPR rules.

Response: Many of these comments regarding Step 4 issues are addressed elsewhere in this document or in the *RTC* document. The EPA's authority to establish unit- or source-specific emissions rates is addressed in section IV.B.1 of this document. Responses to comments and adjustments in the timing requirements of the final rule compared to proposal are discussed in VI.A. Responses to comments and adjustments in emissions control requirements for non-EGUs in the final rule compared to proposal are in section VI.C of this document.

Responses to comments on the EGU trading program enhancements and adjustments in the final rule are contained in section VI.B of this document. However, here, in light of the changes in the emissions trading program for EGUs that we are finalizing in this action as compared to prior EGU emissions trading programs promulgated to address good neighbor obligations under other NAAQS, we set forth responses to comments specific to this topic.

The EPA finds that these comments confuse Step 3 emissions reduction stringency determinations with Step 4 implementation program details. In this rulemaking's Step 3 analysis, the EPA is measuring emissions reduction potential from improving effective emissions rates across groups of EGUs adopting applicable pollution control measures and selecting a uniform control level whose effective emissions rates deliver an acceptable outcome under the multifactor test (including a finding of no overcontrol at the selected control stringency level). The ''amounts'' defined as significant contribution to nonattainment and interference with maintenance are

[95] Section III of the Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes the 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.

emissions that occur at effective emissions rates above the control stringency level selected at Step 3. That is, if a state's affected EGUs fail to reduce their effective emissions rates in line with the widely available and cost-effective control measures identified, they have therefore failed to eliminate their significant contribution to nonattainment and interference with maintenance of this NAAQS.

In this rule, the EPA is finalizing several ''enhancements'' to its existing Group 3 emissions trading program for ozone season NO_X, for reasons explained in section VI.B.1 of this document. In general, these changes will ensure that the emissions control program promulgated for EGUs at Step 4 of the EPA's 4-step interstate transport framework is in alignment with the emissions control stringency determinations the EPA made at Step 3. These enhancements reflect lessons learned through the EPA's experience with prior trading programs implemented under the good neighbor provision and ensure that the implementation of the elimination of significant contribution through an emissions trading program remains durable through a period of power sector transition. None of commenters' arguments against the EPA's authority to implement these enhancements are persuasive.

First, the EPA is not mandating that any EGU must install SCR technology. All but one of the enhancements to the trading program continue to be implemented through allowance-holding requirements under the mass-based emissions budget and trading system, including the backstop rate. (The secondary emissions limitation, which is not implemented through allowance-holding requirements under the mass-based emissions budget and trading system, and which is discussed in section VI.B.1.c.ii of this document, merely establishes a stronger deterrent for a type of conduct that was already strongly discouraged under the pre-existing trading program regulations). Nonetheless, the EPA *does* have the authority to impose unit-specific emissions limits under the exercise of its FIP authority, and it has done so in this action for non-EGU industrial sources. This authority is distinct from the EPA's title I permitting authority as discussed by certain commenters, and the scope of that permitting authority is not relevant to this action.

The quantification of emissions budgets in an allowance-based emissions trading program is one of multiple potential Step 4 implementation program design choices that states and the EPA have authority to select in securing the emissions reductions deemed necessary under Step 3. *See* CAA section 110(a)(2)(A). The EPA and the states routinely determine control stringency on an emissions rate basis in line with demonstrated pollution control opportunities, and both the EPA and the states have implementation program design discretion to determine what compliance requirements, whether expressed on a rate, mass, concentration, or percentage basis, will assure an emissions performance that reflects the control stringency required. Dynamic budgets in the Step 4 implementation of this rule are simply to ensure the trading program continues to incentivize the implementation of the EGU control strategies we find are necessary to eliminate significant contribution at Step 3. The key distinction between dynamic budget approaches and preset budget approaches is not one in stringency or authority, but rather in timing and data resources for determining the suitable mass-based limits that are as well-matched as possible to expected emissions of the affected EGUs achieving the emissions rate-based control stringency deemed necessary under Step 3 to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA does not agree that the administrative mechanisms by which it will implement ''dynamic budgeting'' conflict with CAA section 307(d) or the Administrative Procedure Act. The EPA is promulgating a complete FIP in this action, and the codified language of that FIP will not need to be modified as budgets are adjusted. This is because the FIP establishes the formula by which the budgets will be calculated each year (with preset budgets functioning as a floor from 2026 through 2029). This is no different than how the EPA has implemented other calculations such as updating allocations using a rolling set of data in its prior CSAPR trading programs. *See, e.g.,* 87 FR 10786. We view these actions as fundamentally ministerial in nature in that no exercise of Agency discretion is required. This process will rely on notices of availability of the relevant data in the **Federal Register**, coupled with an opportunity for the public to correct any errors they may identify in the data before the EPA sets each updated budget. See section VI.B.4 for more detail on how the EPA intends to implement dynamic budgeting. As in prior transport rules, this rule provides the opportunity for administrative appeal should an interested party identify some flaw in the EPA's updated data. See 40 CFR 78.1(b)(19)(i) (2023). That process is coupled with the availability of judicial review should the party remain dissatisfied with the EPA's resolution of complaints. *See* 40 CFR 78.1(a)(2) (requiring administrative adjudication as a prerequisite for judicial review). This administrative process has worked well throughout the history of implementing good neighbor trading programs under Part 97, and no such disputes have necessitated judicial resolution.

Further, because the dynamic budgets simply implement the stringency level reflective of the emissions control performance the EPA has determined at Step 3 for the covered EGUs, the EPA does not agree that any ''potential variables'' that are unforeseeable now could upset the basis for the formula the EPA is establishing in this action. The EPA has adjusted the role of dynamic budgeting in this final rule as compared to the proposal. See sections VI.B.1 and VI.B.4 of the preamble. In particular, the EPA is applying an approach to budget setting through 2029 that will use the greater of either a preset budget based on information known to the Agency at the time of this action, or the dynamic budget to be calculated based upon future data yet to be reported. Thus, through 2029 the imposition of a dynamic budget would only increase rather than diminish the emissions allowed for that control period compared to the preset budgets established in this action. In addition, the EPA will determine each state's dynamic budget based on a rolling 3-year average of the state's heat input, thus smoothing out trends to account for interannual variability in demand and heat input and provide greater certainty and predictability as the budget updates from year to year.

Moreover, the EPA does not agree that the EPA is constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA finds good reason based on its experience with trading programs using fixed budgets why this approach does not necessarily ensure the elimination of significant contribution in perpetuity. The EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR

23121–22.[96] The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that the mass-based emissions budget incentivize continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. The dynamic budget-setting process preserves these incentives over time by calculating the state emissions budgets for each future control period so as to reflect the Step 3 control stringency finalized in this rule as applied to the most current information regarding the composition of the power sector in the control period. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions rates that apply in perpetuity. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96. The EPA does not agree that either dynamic budgeting or the backstop rate results in overcontrol. *See* section V.D.4 of this document.

The EPA is enhancing the trading program to help reconcile the approach of using mass-based budgets to achieve the elimination of significant contribution with the *Wisconsin* directive to provide a complete remedy under the good neighbor provision. This approach also better accords with ensuring measures to attain and maintain the NAAQS are permanent and enforceable. The dynamic budget approach recognizes that the uncertainty around future fleet conditions increases the further into the future one looks (and the EPA must look further under the ''full remedy'' directive). To preserve its ability to successfully implement its identified Step 3 stringency, the EPA is designing the implementation of this rule's emissions control program to benefit from the future availability of better data from the regulated sources to inform its application of its stringency measures identified in this rule.

The EPA does not agree with commenters who suggest that these enhancements are undertaken for the purpose of a non-statutory ''environmental justice'' objective. As explained in section VI.B of this document, certain enhancements to the trading program ensure that each EGU is adequately incentivized to continuously operate its emissions controls once those controls are installed. One commenter contends that the backstop emissions rate is not authorized based on environmental justice considerations, since it is not necessary and is overcontrol with respect to the EPA's statutory authority to address good neighbor obligations. But the EPA disagrees with the premise that these enhancements are unrelated to the statutory obligation to eliminate significant contribution. Taking measures to ensure that each upwind source covered by an emissions trading program to eliminate significant contribution is operating its installed pollution controls on a more continuous and consistent basis throughout the ozone season is entirely appropriate in light of the daily nature of the ozone problem, the impacts to public health and the environment from ozone that can occur through short-term exposure (*e.g.,* over a course of hours), the fact that the 2015 ozone NAAQS is expressed as an 8-hour average, and that only a small number of days in excess of the ozone NAAQS are necessary to place a downwind area in nonattainment, resulting in continuing and/or increased regulatory burden on the downwind jurisdiction. *See* section III.A of this document.

Further, the D.C. Circuit has held that the EPA must ensure that its good neighbor program has eliminated *each* state's sources from continuing to significantly contribute to nonattainment or interfere with maintenance in downwind states. *See North Carolina,* 531 F.3d at 921. The commenters neglect to acknowledge the scenario that has frequently borne out in prior programs, in which future fleet changes that were not known at the time of initial setting of state emissions budgets produce unexpected ''hot air'' in the budget that, if unaccounted for, other units can exploit to forgo identified cost-effective mitigation measures deemed necessary to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA's experience is that fixed mass-based budgets that are determined based only on the profile of the power sector at the time the rule is promulgated, and without any additional requirement for pollution controls operation, can become quickly obsolete if the composition of the group of affected EGUs changes notably over time. As some sources retire, other sources relax their operation of NO_X controls in response to a growing surplus of allowances, even though the EPA had concluded that ongoing operation of those controls is necessary to meet the statutory good neighbor requirements. For instance, under the CSAPR Update, in the 2018–2020 period, the fixed budget approach enabled large, frequently run units with existing SCR controls to not optimize those controls even though the EPA's assessment (as reflected in the CSAPR Update) was that the optimization of those controls was necessary to eliminate significant contribution. This deterioration in emission rate at SCR-controlled coal plants was widely observed across the CSAPR Update geography as the program advanced into later years and allowance price deteriorated. Whereas coal sources with SCR performed, on average, at a 0.086 lb/mmBtu rate in 2017, that same set of sources saw their environmental performance worsen to a 0.099 lb/mmBtu rate in 2020. A Congressional Research Service Report on EPA prior CSAPR trading programs indicated low prices observed in later years ''could lead to some decisions not to run some pollution controls at maximum output. This would, in turn, lead to higher emissions''.[97]

In the case of individual units, this deterioration in performance can be quite pronounced and can occur as quickly as the second or third control period, as in the case of Miami Fort Unit 7 in Ohio in 2019, discussed in section V.B of this document. The absence of a sufficient incentive under the trading program to implement the identified control strategy at Step 3 can even result in collective emissions that exceed state-wide assurance levels. The EPA established these levels beginning with CSAPR, above which enhanced allowance-surrender requirements are triggered, in an effort to ensure sources in each state are held to eliminate their own significant contribution, which the D.C. Circuit has held is legally required, *see North Carolina,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). In four instances over the course of the 2019, 2020, and

[96] Further, in the Revised CSAPR Update, the EPA acknowledged that a mechanism like dynamic budgeting could be appropriate for a transport rule with longer time horizons. We stated in response to comments that we were not ''in this action, including an adjustment mechanism to further adjust state emission budgets to account for currently unknown or uncertain retirements after the finalization of this rule . . . . EPA observes that the commenter's proposed mechanism would become increasingly valuable for rules where the timeframe extends further into the future where retirement uncertainty is higher.'' Revised CSAPR Update Response to Comments, EPA–HQ–OAR–2020–0272–219, at 153.

[97] Shouse, Kate. ''The Clean Air Act's Good Neighbor Provision: Overview of Interstate Air Pollution Control''. Congressional Research Services. August 30, 2018. Available at *https://sgp.fas.org/crs/misc/R45299.pdf.*

2021 control periods under the CSAPR Update, sources in Mississippi and Missouri collectively exceeded their state-wide assurance levels in part due to deterioration in emissions performance that can be attributed to a glut of allowances within the CSAPR Update. See section VI.B.8 of the preamble.

Thus, while this trading program structure may achieve some environmental benefit through fixed emissions budgets for initial control periods, over time those fixed budgets cease to have their intended effect, and remaining operating facilities can, and have, increased emissions or even discontinued the operation of their emissions controls. This, in turn, can lead to the continuation (or re-emergence) of significant contribution in terms of a recurrence of excessive emissions that had been slated for permanent elimination under the EPA's determinations at Step 3. Although the EPA has always intended for its trading programs to provide flexibility, the Agency did not expect and has certainly never endorsed the use of that flexibility to stop the operation of controls that have already been installed. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the historical data establishes a real risk of ''under-control'' if the existing trading framework is not improved upon. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

This result is also inconsistent with the statutory mandate to ''prohibit'' significant contribution and interference with maintenance of the NAAQS in downwind 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 to it.'' 42 U.S.C. 7426(c)(2) (emphasis added). *See also North Carolina,* 531 F.3d at 906–08 (each state must be held to the elimination of its own significant contribution). The purpose of the Agency's interstate trading programs under the good neighbor provision is to afford sources some flexibility in achieving region-wide emissions reductions; however, there is no justification that can be sustained within that framework for sources in certain areas within that region, or during periods of high ozone when good emissions performance is most essential, to emit at levels well in excess of the EPA's Step 3 determinations of significant contribution. Significant contribution, according to the statute, must be ''prohibited.'' CAA section 110(a)(2)(D)(i).

Thus, these trading program enhancements are within the EPA's authority under CAA section 110(a)(2)(D)(i)(I) to eliminate interstate ozone pollution that significantly contributes to nonattainment or interferes with maintenance in downwind states. These enhancements ensure the elimination of significant contribution across all upwind states and throughout each ozone season. We observe in the Ozone Transport Policy Analysis Final Rule TSD, section E, that the trading program enhancements may also benefit underserved and overburdened communities downwind of EGUs in the covered geography of the final rule. See section VI.B of this document. This does not detract from the statutorily-authorized basis for these changes, and the EPA finds nothing impermissible in acknowledging the reality of these potential benefits for underserved and overburdened communities.

The EPA appreciates a commenter's concern that our actions be legally defensible. The EPA acknowledges that the changes to the trading program structure for implementing good neighbor obligations discussed here constitute a change in the policy underlying its prior transport-rule trading programs for EGUs. However, the EPA is confident that these changes are in compliance with the holdings in judicial decisions reviewing prior transport rules. The fact that the EPA is making changes does not somehow render these enhancements legally impermissible or even subject to a heightened standard of review. *See FCC* v. *Fox Television Stations,* 556 U.S. 502, 514 (2009) (''We find no basis in the Administrative Procedure Act or in our opinions for a requirement that all agency change be subjected to more searching review.''). We have explained previously and elsewhere in the record that there are ''good reasons'' for the ''new policy.'' *See id.* at 515. And, we are of course fully aware that we have changed our position. *See id.* at 514–15. Specifically, we have gone from previously treating fixed, mass-based budgets as sufficient to eliminate significant contribution, to an approach for purposes of the 2015 ozone NAAQS reflecting a more nuanced understanding of how an emissions trading program that does not properly anticipate future fleet conditions at Step 4 may fail to achieve the elimination of emissions that should be prohibited based on our findings at Step 3. Further, we find there to be no ''serious reliance interests'' that have been or even could have been ''engendered'' by any prior policy on these issues, *see id.* at 515–16. The EPA is implementing these enhancements for the first time with respect to a new obligation—good neighbor requirements for the 2015 ozone NAAQS. No party reasonably could have invested substantial resources to-date to comply with an obligation that was heretofore undefined; and no commenter has supplied any information to the contrary.

2. FIP Authority for Each State Covered by the Rule

On October 26, 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).[98] 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 CAA 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 document.

The EPA is finalizing this FIP action now to address 23 states' good neighbor obligations for the 2015 ozone NAAQS.[99] For each state for which the EPA is finalizing this FIP, the EPA either issued final findings of failure to submit or has issued a final disapproval of that state's SIP submission.

Several commenters asserted that the sequence of the EPA's actions, and in particular, the timing of its proposed FIP (which was signed on February 28,

[98] *National Ambient Air Quality Standards for Ozone,* Final Rule, 80 FR 65292 (Oct. 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.

[99] The EPA notes that it is subject to, and has met through this action, a consent decree deadline to promulgate FIPs addressing 2015 ozone NAAQS good neighbor obligations for the states of Pennsylvania, Utah, and Virginia. *See Sierra Club et al.* v. *Regan,* No. 3:22–cv–01992–JD (N.D. Cal. entered January 24, 2023).

2022, and published on April 6, 2022) in relation to the timing of its proposed SIP disapprovals (most of which were published on February 22, 2022, four of which were published on May 24, 2022, and one of which was published on October 25, 2022), was either unlawful or unreasonable in light of the sequence of steps required under CAA section 110(k) and (c).

These commenters are incorrect. As an initial matter, concerns about the timing or substance of the EPA's actions on the SIP submittals are beyond the scope of this action. Nor are the timing or contents of merely proposed actions to be considered final agency actions or subject to judicial review. *See In re Murray Energy,* 788 F.3d 330 (D.C. Cir. 2015). With these principles in mind, the timing of this final action is lawful under the Act. First, 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.[100] CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval or making a finding of failure to submit. The Supreme Court recognized in *EME Homer City* 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.''[101] Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final SIP disapproval (or finding no SIP was submitted). 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.

Second, and more importantly, the EPA has established predicate authority to promulgate FIPs for all of the covered states through its action with respect to the relevant SIP submittals. A brief history of these actions follows:

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).[102] Alabama subsequently withdrew its SIP submission and re-submitted a SIP submission on June 22, 2022. The EPA proposed to disapprove that SIP submittal on October 25, 2022.[103] The EPA proposed to disapprove good neighbor SIP submissions for four additional states, California, Nevada, Utah, and Wyoming, on May 24, 2022.[104]

Subsequently, on January 31, 2023, the EPA Administrator signed a single disapproval action for all of the above states, with the exception of Tennessee and Wyoming.[105] This action established the EPA's authority to promulgate FIPs for the disapproved states. (As explained in section IV.F of this document, the Agency is deferring action at this time for Tennessee and Wyoming with respect to its proposed FIP actions for those states. As discussed in section IV.F of this document, the EPA's most recent modeling and air quality analysis indicates that several states may be linked to downwind receptors for which we had not previously proposed disapproval or FIP action. The EPA anticipates addressing remaining interstate transport obligations for the 2015 ozone NAAQS for these in a subsequent rulemaking.)

Additionally, the EPA has taken action that has triggered the EPA's obligation under CAA section 110(c) to promulgate FIPs addressing the good neighbor provision for several downwind 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.[106] 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,[107] the EPA currently has authority under the December 5, 2019, findings of failure to submit to issue FIPs for New Mexico, Pennsylvania, Utah, and Virginia. In this final rule, the EPA is issuing FIP requirements for Pennsylvania, Utah, and Virginia.[108]

Further information on the procedural history establishing the EPA's authority for this final rule is provided in a document in the docket.[109]

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[100] 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 the 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 the EPA's deadline to take final action on New York's SIP submission is extended to December 30, 2022. By stipulation of the parties, the December 15, 2022, date in all three of these consent decrees was extended to January 31, 2023. By further stipulation of the parties in the *Downwinders at Risk* case, the January 31, 2023, date was further extended to December 15, 2023 for the EPA to act on the SIP submissions from the states of Arizona, Tennessee, and Wyoming.

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

[102] *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, Ohio, Wisconsin).

[103] *See* 87 FR 64412.

[104] *See* 87 FR 31443 (California); 87 FR 31485 (Nevada); 87 FR 31470 (Utah); 87 FR 31495 (Wyoming).

[105] *See* 88 FR 9336.

[106] *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).

[107] *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).

[108] *WildEarth Guardians* v. *Regan,* No. 1:22–cv–00174 (D.N.M. entered Aug. 16, 2022); *Sierra Club et al.* v. *EPA,* No. 3:22–cv–01992 (N.D. Cal. entered Jan. 24, 2023).

[109] *See* ''Final Rule: 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.'' This document updates a prior document of the same title provided

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While the EPA's previous actions are sufficient to establish that the EPA's promulgation of this FIP action at this time is lawful, the timing of this action is all the more reasonable in light of the need for the EPA to address good neighbor obligations consistent with the rest of title I of the CAA. In particular, the D.C. Circuit in *Wisconsin* held that states and the 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).[110] 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,[111] which fell on August 3, 2021.[112] As discussed in section VI.A of this document, by finalizing this action now, the EPA is able to implement initial required emissions reductions to eliminate significant contribution by the 2023 ozone season, which is the last full ozone season before the next attainment date, the Moderate area attainment date of August 3, 2024. The *Wisconsin* court emphasized that the 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 in alignment with the downwind attainment schedule, and that is precisely what the EPA is doing here.[113] The EPA provides further response to the comments on this issue in section 1 of the *RTC* document.

C. Other CAA Authorities for This Action

1. Withdrawal of Proposed Error Correction for Delaware

The EPA proposed at 87 FR 20036 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 proposed to determine that the basis for the prior SIP approval was invalidated by the Agency's more recent technical evaluation of air quality modeling performed in support of the proposed rule,[114] and that Delaware had unresolved interstate transport obligations for the 2015 ozone NAAQS. The EPA also proposed to issue a FIP for Delaware given these unresolved interstate transport obligations. However, based on the updated air quality modeling described in section IV.F. of this document and the technical assessment that informs this final rule, the EPA finds that Delaware is not projected to be linked to any downwind receptor above the 1 percent of the NAAQS threshold in 2023. Thus, based on the record before the Agency now, the original approval of Delaware's SIP submission was not in error, and the EPA is withdrawing its proposed error correction and proposed FIP for Delaware.

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

The EPA is finalizing its determination 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 final rule, as defined in this section. Certain areas of Indian country within the geography of the rule are or may be subject to state implementation planning authority. Other areas of Indian country within that geography are 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.[115] As described later, the EPA is including 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.

a. Indian Country Subject to Tribal Jurisdiction

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 in this section) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction—the EPA here makes 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 will be referred to as the CAA section 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.[116]

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at proposal (Document no. EPA–HQ–OAR–2021–0668–0131).

[110] *Wisconsin* v. *EPA,* 938 F.3d 303, 313–14 (D.C. Cir. 2019) (citing *North Carolina* v. *EPA,* 531 F.3d 896, 911–13 (D.C. Cir. 2008).

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

[112] *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).

[113] 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)).

[114] *See* the Air Quality Modeling Proposed Rule TSD in the docket for this rule.

[115] We note that, consistent with the 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 IV.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 IV.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 the 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.

[116] *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.'').

The EPA hereby finds that it is both necessary and appropriate to regulate all new and existing EGU and industrial sources meeting the applicability criteria set forth in this 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 finding, the geographic scope of coverage of the rule means the areas of the United States encompassed within the borders of the states the EPA has determined to be linked at Steps 1 and 2 of the 4-step interstate transport framework.[117] For EGU applicability criteria, *see* section VI.B of this document; for industrial-source applicability criteria, *see* section VI.C of this document. To EPA's knowledge, only one existing EGU or industrial source is located within the CAA section 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 finding is consistent with the 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, the 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 48293 (describing the CSAPR methodology of allowance allocation under the ''Indian country new unit set-aside'' provisions); *see also id.* at 48217 (explaining the 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, the 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 rule, the EPA is taking an approach similar to the prior CSAPR rulemakings with respect to regulating sources in the CAA section 301(d) FIP areas.[118] The EPA believes this approach is necessary and appropriate for several reasons. First, the purpose of this rule is to address the 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 rule, the EPA is applying—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 (as determined separately for linkages existing in 2023, and linkages persisting in 2026). (*See* section V of this document for a discussion of EPA's determination of control stringency for this rule.) 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, the 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 reduce 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 rule, the importance of a uniform level of stringency that extends to and includes the CAA section 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, to avoid the regulatory costs that would be imposed under this 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 EGU or industrial sources not subject to the rule but located in a geography where the same types of sources 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 the EPA's view, to avoid creating, via this rule, a structure of incentives that may cause generation or production—and the associated NO_X emissions—to shift into the CAA section 301(d) FIP areas to escape regulation needed to eliminate interstate transport under the good neighbor provision.

The EPA finds it is appropriate to directly implement the rule's requirements in the CAA section 301(d) FIP areas in this action rather than at a later date. Tribes have the opportunity to seek treatment as a state (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 CAA section 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

[117] With respect to any industrial sources located in the CAA section 301(d) FIP areas, the geographic scope of coverage of this rule does not include those states for which the EPA finds, based on air quality modeling, that no further linkage exists by the 2026 analytic year at Steps 1 and 2. The states in this rule not linked in 2026 are Alabama, Minnesota, and Wisconsin.

[118] *See* section VI.B.9 of this document for a discussion of revisions that are being made 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.

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 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 VI.A of this document, the EPA is 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 the application of this FIP in the CAA section 301(d) FIP areas, NO_X emissions from any existing or new EGU or non-EGU sources located in, or locating in, the CAA section 301(d) FIP areas within the covered geography of the rule would remain unregulated for purposes of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS and could continue or potentially increase. This would be inconsistent with the 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 CAA section 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. The EPA's Fiscal Year 2022–2026 Strategic Plan [119] 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.'' As described in section X.F of this document, the EPA offered Tribal consultation to 574 Tribes in April of 2022 and received no requests for Tribal consultation after publication of the proposed rulemaking. 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 rule.

Therefore, to ensure timely alignment of all needed emissions reductions within the timetables of this 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 CAA section 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,[120] the EPA finds it both necessary and appropriate that all existing and new EGU and industrial sources that are located in the CAA section 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 issues this finding under CAA section 301(d)(4) of the Act and 40 CFR 49.11. Further, to avoid ''unreasonable delay'' in promulgating this FIP, as required under section 49.11, the EPA makes this finding now, to align emissions reduction obligations for any covered new or existing sources in the CAA section 301(d) FIP areas with the larger schedule of reductions under this rule. Because all other covered EGU and non-EGU sources within the geography of this 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 including the CAA section 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 rule, and this determination does not preclude the tribes from taking such actions. Although the formal tribal consultation process associated with this action has concluded, the EPA is willing and available to engage with any tribe as this rule is implemented.

b. 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).[121]

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.[122] 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

[119] *https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf.*

[120] Executive Order 13985 (January 20, 2021) (86 FR 7009 (January 25, 2021)): *https://www.govinfo.gov/content/pkg/FR-2021-01-25/pdf/2021-01753.pdf.*

[121] 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 the EPA's decision, described in this section, on October 1, 2020.

[122] Available in the docket for this rulemaking.

(collectively ''excluded Indian country lands'').

The 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 the EPA's approval of Oklahoma's SAFETEA request.[123] 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** document published on February 13, 2023 (88 FR 9336), the EPA disapproved 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 the EPA's October 1, 2020 SAFETEA approval, the EPA has authority under CAA section 110(c) to promulgate a FIP as needed to address the disapproved aspects of Oklahoma's good neighbor SIP submittal.[124] In accordance with the previous discussion, the EPA's FIP authority in this circumstance extends to all Indian country in Oklahoma, other than the excluded Indian country lands, as described previously.[125] 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,* the EPA's FIP authority under CAA section 110(c) also applies to any Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority. The EPA's FIP authority under CAA section 110(c) similarly applies 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 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 following finalization of this rule, and such change affects the exercise of FIP authority provided under section 110(c) of the Act,[126] then, to the extent any such areas would fall more appropriately within the CAA section 301(d) FIP areas as described in section III.C.2.a of this document, the EPA's necessary or appropriate finding as set forth above with respect to all other CAA section 301(d) FIP areas within the geographic scope of coverage of the rule would apply.

D. Severability

The EPA regards this action as a complete remedy, which will as expeditiously as practicable implement good neighbor obligations for the 2015 ozone NAAQS for the covered states, consistent with the requirements of the Act. *See North Carolina* v. *EPA,* 531 F.3d 896, 911–12 (D.C. Cir. 2008); *Wisconsin* v. *EPA,* 938 F.3d 303, 313–20 (D.C. Cir. 2019); *Maryland* v. *EPA,* 958 F.3d 1185, 1204 (D.C. Cir. 2020); *New York* v. *EPA,* 964 F.3d 1214, 1226 (D.C. Cir. 2020); *New York* v. *EPA,* 781 Fed. App'x 4, 7–8 (D.C. Cir. 2019) (all holding that the EPA must address good neighbor obligations as expeditiously as practicable and by no later than the next applicable attainment date). Yet should a court find any discrete aspect of this document to be invalid, the Agency believes that the remaining aspects of this rule can and should continue to be implemented to the extent possible. In particular, this action promulgates a FIP for each covered state (and, pursuant to CAA section 301(d), for each area of tribal jurisdiction within the geographic boundaries of those states). Should any jurisdiction-specific aspect of the final rule be found invalid, the EPA views this rule as severable along those state and/or tribal jurisdictional lines, such that the rule can continue to be implemented as to any remaining jurisdictions. This action promulgates discrete emissions control requirements for the power sector and for each of seven other industries. Should any industry-specific aspect of the final rule be found invalid, the EPA views this rule as severable as between the different industries and different types of emissions control requirements. This is not intended to be an exhaustive list of the ways in which the rule may be severable. In the event any part of it is found invalid, our intention is that the remaining portions should continue to be implemented consistent with any judicial ruling.

The EPA's conclusion that this rule is severable also reflects the important public health and environmental benefits of this rulemaking in eliminating significant contribution and to ensure to the greatest extent possible the ability of both upwind states and downwind states and other relevant stakeholders to be able to rely on this final rule in their planning. *Cf. Wisconsin,* 938 F.3d at 336–37 (''As a general rule, we do not vacate regulations when doing so would risk significant harm to the public health or the environment.''); *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008) (noting the need to preserve public health benefits); *EME Homer City* v. *EPA,* 795 F.3d 118, 132 (D.C. Cir. 2015) (noting the need to avoid disruption to emissions trading market that had developed).

IV. 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 final rule, the EPA evaluated air quality to identify receptors at Step 1 for two

[123] The 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 the EPA's approval of Oklahoma's SAFETEA request.

[124] The antecedent fact that the state had the authority and jurisdiction to implement requirements under the good neighbor provision, in the 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).

[125] With respect to those areas of Indian country constituting ''excluded Indian country lands'' in the State of Oklahoma, as defined supra, the EPA applies 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.

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

analytic years: 2023 and 2026. The EPA evaluated interstate contributions to these receptors from individual upwind states at Step 2 for these two analytic years. In selecting these years, the EPA views 2023 and 2026 to constitute years by which key emissions reductions from EGUs and non-EGUS can be implemented ''as expeditiously as practicable.'' 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). To demonstrate attainment by these deadlines, downwind states would be required to rely on design values calculated using ozone data 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 final rule can assist the downwind areas with demonstrating attainment or receiving extensions of attainment dates under CAA section 181(a)(5). (The EPA explains in detail in sections V and VI of this document its determinations regarding which emissions reduction strategies can be implemented by 2023, and which emissions reduction strategies require additional time beyond that ozone season, or the 2026 ozone season.)

It would not be logical for the EPA to analyze any earlier year than 2023. The EPA continues to interpret the good neighbor provision as forward-looking, based on Congress's use of the future-tense ''will'' in CAA 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 the proposal, the EPA recognized that the 2021 Marginal area attainment date had already passed. Further, based on the timing of the proposal, it was not possible to finalize this rulemaking before the 2022 ozone season had also passed. Thus, the EPA has selected 2023 as the first appropriate future analytic year for this final 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 2026 to ensure a complete Step 3 analysis for future ozone transport contributions to downwind areas. As noted above, 2023 and 2026 coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS. In addition, 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 to fully address significant contribution. In all cases, 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.

Comment: A commenter claims that the EPA has not followed the holdings of *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), *North Carolina* v. *EPA,* 550 F.3d 1176 (D.C. Cir. 2008), and *Maryland* v. *EPA,* 958 F. 3d 1185 (D.C. Cir. 2020) in the selection of analytic years, in that commenter interprets those decisions as holding that the EPA must ''harmonize'' the exact timing of upwind emissions reductions with when downwind states implement their required reductions. Commenter also points to the EPA's proposed action on New York's Good Neighbor SIP submission specifically to argue that the EPA is treating upwind and downwind states dissimilarly. Commenter also cites CAA sections 172, 177, and 179 to argue the EPA did not properly align upwind and downwind obligations. Several commenters believe the EPA should defer implementing good neighbor requirements until downwind receptor areas have first implemented their own emissions control strategies.

Response: The EPA maintains that 2023 is an appropriate analytic year and comports with the relevant caselaw. Section VI.A further discusses the compliance schedule for emissions reductions under this rule. Commenter misreads the *North Carolina, Wisconsin,* and *Maryland* decisions as calling for good neighbor analysis and emissions controls to be aligned with the timing of the *implementation* of nonattainment controls by downwind states. However, the D.C. Circuit has held that the *statutory attainment dates* are the relevant downwind deadlines the EPA must align with in implementing the good neighbor provision. In *Wisconsin,* the court held, ''In sum, under our decision in *North Carolina,* the Good Neighbor Provision calls for elimination of upwind States' significant contributions *on par with the relevant downwind attainment deadlines.*'' *Wisconsin,* 938 F.3d. at 321 (emphasis added).

After that decision, the EPA interpreted *Wisconsin* as limited to the attainment dates for Moderate or higher classifications under CAA section 181 on the basis that Marginal nonattainment areas have reduced planning requirements and other considerations. *See, e.g.,* 85 FR 29882, 29888–89 (May 19, 2020) (proposed approval of South Dakota's 2015 ozone NAAQS good neighbor SIP). However, on May 19, 2020, the D.C. Circuit in *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020), applying the *Wisconsin* decision, rejected that argument and held that the EPA must assess air quality at the next downwind attainment date, including Marginal area attainment dates under CAA section 181, in evaluating the basis for the EPA's denial of a petition under CAA section 126(b). 958 F.3d at 1203–04. After *Maryland,* the EPA acknowledged that the Marginal attainment date is the first attainment date to consider in evaluating good neighbor obligations. *See, e.g.,* 85 FR 67653, 67654 (Oct. 26, 2020) (final approval of South Dakota's 2015 ozone NAAQS good neighbor SIP).

The D.C. Circuit again had occasion to revisit the Agency's interpretation of *North Carolina, Wisconsin,* and *Maryland,* in a challenge to the Revised CSAPR Update brought by the Midwest Ozone Group (MOG). The court declined to entertain similar arguments to those presented by commenters here and instead in a footnote explained that it had ''exhaustively summarized the regulatory framework governing EPA's conduct'' and that it ''[drew] on those decisions and incorporate them herein by reference,'' citing, among other cases, *Maryland,* 958 F.3d 1185, and *New York,* 781 F. App'x 4. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023), Slip Op. at 3 n.1.

The relevance of CAA sections 172, 177, and 179 to the selection of the analytic year in this action is not clear. Commenter cites these provisions to conclude that the EPA did not appropriately consider downwind attainment deadlines and the timing of upwind good neighbor obligations. These provisions are found in subpart I, and while they may have continuing relevance or applicability to aspects of ozone nonattainment planning requirements, the nonattainment dates for the 2015 ozone NAAQS flow from subpart 2 of title I of the CAA, and specifically CAA section 181(a). Applying that statutory schedule to the designations for the 2015 ozone NAAQS, the EPA has promulgated the applicable attainment dates in its regulations at 40 CFR 51.1303. The effective date of the initial designations for the 2015 ozone NAAQS was August 3, 2018 (83 FR 25776, June 4, 2018, effective August 3, 2018).[127] Thus, the first deadline for attainment planning under the 2015 ozone NAAQS was the Marginal attainment date of August 3, 2021, and the second deadline for attainment planning is the Moderate attainment date of August 3, 2024. If a Marginal area fails to attain by the attainment date it is reclassified, or ''bumped up,'' to Moderate. Indeed, the EPA has just completed a rulemaking action reclassifying many areas of the country from Marginal to Moderate nonattainment, including all of the areas where downwind receptors have been identified in our 2023 modeling as well as many other areas of the country. 87 FR 60897, 60899 (Oct. 7, 2022).

Other than under the narrow circumstances of CAA section 181(a)(5) (discussed further in this section), the EPA is not permitted under the CAA to extend the attainment dates for areas under a given classification. That is, no matter when or if the EPA finalizes a determination that an area failed to attain by its attainment date and reclassifies that area, the attainment date remains fixed, based on the number of years from the area's initial designation. *See, e.g.,* CAA section 182(i) (authorizing the EPA to adjust any applicable deadlines for newly reclassified areas ''other than attainment dates''). As the D.C. Circuit has repeatedly made clear, the statutory attainment schedule of the downwind nonattainment areas under subpart 2 is rigorously enforced and is not subject to change based on policy considerations of the EPA or the states.

> [T]he attainment deadlines, the Supreme Court has said, are ''the heart'' of the Act. *Train* v. *Nat. Res. Def. Council,* 421 U.S. 60, 66, 95 S.Ct. 1470, 43 L.Ed.2d 731 (1975); *see Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002) (''the attainment deadlines are central to the regulatory scheme'') (alteration and internal quotation marks omitted). The Act's central object is the ''attain[ment] [of] air quality of specified standards [within] a specified period of time.'' *Train,* 421 U.S. at 64–65, 95 S.Ct. 1470.

Wisconsin, 938 F.3d at 316. *See also Natural Resources Defense Council* v. *EPA,* 777 F.3d 456, 466–68 (D.C. Cir. 2014) (holding the EPA cannot adjust the section 181 attainment schedule to run from any other date than from the date of designation); *id.* at 468 (''EPA identifies no statutory provision giving it free-form discretion to set Subpart 2 compliance deadlines based on its own policy assessment concerning the number of ozone seasons within which a nonattainment area should be expected to achieve compliance.'') (citing and quoting *Whitman* v. *American Trucking Ass'ns,* 531 U.S. 457, 484, (2001) (''The principal distinction between Subpart 1 and Subpart 2 is that the latter eliminates regulatory discretion that the former allowed.''). Furthermore, as the court in *NRDC* noted, ''[T]he 'attainment deadlines . . . leave no room for claims of technological or economic infeasibility.' '' 777 F.3d at 488 (quoting *Sierra Club,* 294 F.3d at 161) (internal quotation marks and brackets omitted).

With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899. Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* (And the New York City Metropolitan nonattainment area was initially classified as Moderate (see following text for further details).) Even if the EPA had extended the attainment date for any of the downwind areas, it is not clear that it would necessarily follow that the EPA must correspondingly extend or delay the implementation of good neighbor obligations. While the *Wisconsin* court recognized extensions under CAA section 181(a)(5) as a possible source of timing flexibility in implementing the good neighbor provision, 938 F.3d at 320, the EPA and the states are still obligated to implement good neighbor reductions as expeditiously as practicable and are also obligated under the good neighbor provision to address ''interference with maintenance.'' Areas that have obtained an extension under CAA section 181(a)(5) or which are not designated as in nonattainment could still be identified as struggling to maintain the NAAQS, and the EPA is obligated under the good neighbor provision to eliminate upwind emissions interfering with the ability to maintain the NAAQS, as well. *North Carolina,* 531 F.3d at 908–11. Thus, while an extension under CAA section 181(a)(5) may be a source of flexibility for the EPA to consider in the timing of implementation of good neighbor obligations, as *Wisconsin* recognized, it is not the case that the EPA *must* delay or defer good neighbor obligations for that reason, and neither the D.C. Circuit nor any other court has so held.

Commenter is therefore incorrect to the extent that they argue the selection of 2023 as an analytic year for upwind obligations results in the misalignment of downwind and upwind state obligations. To the contrary, both downwind and upwind state obligations are driven by the statutory attainment date of August 3, 2024 for Moderate areas, and the last year that air quality data may impact whether nonattainment areas are found to have attained by the attainment date is 2023. That is why, in the recent final rulemaking determinations that certain Marginal areas failed to attain by the attainment date, bumping those areas up to Moderate, and giving them SIP submission deadlines, reasonably available control measures (RACM), and reasonably RACT implementation deadlines, the EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. See 87 FR 60897, 60900 (Oct. 7, 2022). The implementation deadline for RACM and RACT is also January 1, 2023. *Id.* This was in large part driven by the EPA's ozone implementation regulations, 40 CFR 51.1312(a)(3)(i), which previously established a RACT implementation deadline for initially classified Moderate as no later than January 1, 2023, and the modeling and attainment demonstration requirements in 40 CFR 51.1308(d), which require a state to provide for implementation of all control measures needed for attainment no later than the beginning of the attainment year ozone season (*i.e.,* 2023). Given this regulatory history, the EPA can hardly be accused of letting states with nonattainment areas for the 2015 ozone NAAQS avoid or delay their mandatory CAA obligations.

Commenter's proposal that the EPA align good neighbor obligations with the actual implementation of measures in downwind areas is untethered from the statute, as discussed above. It is also unworkable in practice. It would necessitate coordinating the activities of multiple states and EPA regional and headquarters offices to an impossible degree and effectively could preclude the implementation of good neighbor obligations altogether. Commenter does not explain how the EPA or upwind states should coordinate upwind emissions control obligations for states

[127] September 24, 2018, for the San Antonio area. 83 FR 35136 (July 25, 2018).

linked to multiple downwind receptors whose states may be implementing their requirements on different timetables. Less drastic mechanisms than subjecting people living in downwind receptor areas to continuing high levels of air pollution caused in part by upwind-state pollution are available if the actual implementation of mandatory CAA requirements in the downwind areas is delayed: CAA section 304(a)(2) provides for judicial recourse where there is an alleged failure by the Agency to perform a nondiscretionary duty; that recourse is for the Agency to be placed on a court-ordered deadline to address the relevant obligations. *See Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1223–24 (10th Cir. 2013); *Montana Sulphur and Chemical Co.* v. *U.S. EPA,* 666 F.3d 1174, 1190–91 (9th Cir. 2012). Commenter focuses on the EPA's evaluation of New York's Good Neighbor SIP submission to argue the EPA is treating upwind and downwind states dissimilarly. The argument conflates New York's role as both a downwind and an upwind state. In evaluating the Good Neighbor SIP submission that New York submitted, the EPA identified as a basis for disapproval that none of the state emissions control programs New York cited included implementation timeframes to achieve the reductions, let alone ensure they were achieved by 2023. 87 FR 9484, 9494 (Feb. 22, 2022). The EPA conducted the same inquiry into other states' claims regarding their existing or proposed state laws or other emissions reductions claimed in their SIP submissions. *See, e.g.,* 87 FR 9472–73 (evaluating claims regarding emissions reductions anticipated under Maryland's state law); 87 FR 9854 (evaluating claims regarding emissions reductions anticipated under Illinois' state law). Consistent with its treatment of the other upwind states included in this action, the EPA in a separate action disapproved New York's good neighbor SIP submission for the 2015 ozone NAAQS because its arguments did not demonstrate that it had fully prohibited emissions significantly contributing to out of state nonattainment or maintenance problems.

Commenter attempts to contrast this evaluation with what it believes is the EPA's permissive attitude toward delays by downwind states, specifically claiming that ''certain nonattainment areas have delayed implementation of nonattainment controls until 2025 and beyond.'' This apparently references New York's simple cycle and regenerative combustion turbines (SCCT) controls, which commenter cited elsewhere in its comments. New York's SCCT controls were not included by New York in its good neighbor SIP submission, nor was the prior approval of the SCCT controls reexamined by the EPA or reopened for consideration by the Agency in this action. Although not part of this rulemaking, the EPA notes that the SCCT controls were approved by the EPA as a SIP strengthening measure and not to satisfy any specific planning requirements for the 2015 ozone NAAQS under CAA section 182. 86 FR 43956, 43958 (Aug. 11, 2021). The SCCT controls submitted to the EPA were already a state rule, and the only effect under the CAA of the EPA approving them into New York's SIP was to make them federally enforceable. 86 FR 43956, 43959 (Aug. 11, 2021). In other words, approval of the SCCT controls did not relieve New York of its nonattainment planning obligations for the 2015 ozone NAAQS.

The EPA notes that the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area was initially designated as Moderate nonattainment. 83 FR 25776 (June 4, 2018). Pursuant to this designation, New York was required to submit a RACT SIP submission and an attainment demonstration no later than 24 months and 36 months, respectively, after the effective date of the Moderate designation. CAA section 182; 40 CFR 51.1308(a), 51.1312(a)(2). New York submitted a RACT SIP for the 2015 ozone standards on January 29, 2021,[128] and the EPA is currently evaluating that submission. New York has not yet submitted its attainment demonstration, which was due August 3, 2021. Further, the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area remains subject to the Moderate nonattainment area date of August 3, 2024. If it fails to attain the 2015 ozone NAAQS by August 3, 2024, it will be reclassified to Serious nonattainment, resulting in additional requirements on the New York nonattainment area.

In any case, regardless of the status of New York's and the EPA's efforts in relation to the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area (which are outside the scope of this action), the EPA's evaluation of 2023 as the relevant analytic year in assessing New York's and other states' good neighbor obligations is consistent with the statutory framework and court decisions calling on the agency to align these obligations with the downwind areas' statutory attainment schedule. The EPA further responds to these comments in the *RTC* document in the docket.

The remainder of this section includes information on (1) the air quality modeling platform used in support of the final rule with a focus on the base year and future year base case emissions inventories, (2) the method for projecting design values in 2023 and 2026, 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 largest predicted downwind contributions in 2023 and 2026 from each state. The 2016 base period and 2023 and 2026 projected design values and contributions for all ozone monitoring sites are provided in the docket for this rule. The ''Air Quality Modeling Technical Support Document for the Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Final Rulemaking'' (Mar. 2023), hereinafter referred to as the Air Quality Modeling Final Rule TSD, in the docket for this final 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 3 of the 2016-based modeling platform (*i.e.,* 2016v3) for the air quality modeling for this final rule. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and anthropogenic emissions projections for 2023 and 2026. The emissions data contained in this platform represent an update to the 2016 version 2 inventories used for the proposal modeling.

The air quality modeling for this final rule 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 which is the same model that EPA used for the proposed rule air quality modeling.[129] Additional information on the 2016-based air quality modeling platform can be found in the Air Quality Modeling Final Rule TSD.

Comment: Commenters noted that the 2016 base year summer maximum daily average 8-hour (MDA8) ozone predictions from the proposal modeling were biased low compared to the corresponding measured concentrations in certain locations. In this regard, commenters said that model

[128] *https://edap.epa.gov/public/extensions/S4S_Public_Dashboard_2/S4S_Public_Dashboard_2.html.*

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

performance statistics for a number of monitoring sites, particularly those in portions of the West and in the area around Lake Michigan, were outside the range of published performance criteria for normalized mean bias (NMB) and normalized mean error (NME) of less than ±15 percent and less than 25 percent, respectively (Emory, et al., 2017).[130] The commenters said EPA must investigate the factors contributing to low bias and make necessary corrections to improve model performance in the final rule modeling. Some commenters said that EPA should include NO_X emissions from lightning strikes and assess the treatment of other background sources of ozone to improve model performance for the final rule. Additional information on the comments on model performance can be found in the *RTC* document for this final rule.

Response: In response to these comments EPA examined the temporal and spatial characteristics of model under prediction to investigate the possible causes of under prediction of MDA8 ozone concentrations in different regions of the U.S. in the proposal modeling. EPA's analysis indicates that the under prediction was most extensive during May and June with less bias during July and August in most regions of the U.S. For example, in the Upper Midwest region model under prediction was larger in May and June compared to July through September. Specifically, in the proposal modeling, the normalized mean bias for days with measured concentrations ≥60 ppb improved from a 21.4 percent under prediction for May and June to a 12.6 percent under prediction in the period July through September. As described in the Air Quality Modeling Final Rule TSD, the seasonal pattern in bias in the Upper Midwest region improves somewhat gradually with time from the middle of May to the latter part of June. In view of the seasonal pattern in bias in the Upper Midwest and in other regions of the U.S., EPA focused its investigation of model performance on model inputs that, by their nature, have the largest temporal variation within the ozone season. These inputs include emissions from biogenic sources and lightning NO_X, and contributions from transport of international anthropogenic emissions and natural sources into the U.S. Both biogenic and lightning NO_X emissions in the U.S. dramatically increase from spring to summer.[131] [132] In contrast, ozone transported into the U.S. from international anthropogenic and natural sources peaks during the period March through June, with lower contributions during July through September.[133] [134] To investigate the impacts of these sources, EPA conducted sensitivity model runs which focused on the effects on model performance of adding NO_X emissions from lightning strikes, updating biogenic emissions, and using an alternative approach for quantifying transport of ozone and precursor pollutants into the U.S. from international anthropogenic and natural sources. The development of lightning NO_X emissions and the updates to biogenic emissions, are described in section IV.C of this document. In the proposal modeling the amount of transport from international anthropogenic and natural sources was based on a simulation of the hemispheric version of the Community Multi-scale Air Quality Model (H–CMAQ) for 2016.[135] The outputs from this hemispheric modeling were then used to provide boundary conditions for national scale air quality modeling at proposal.[136] Overall, H–CMAQ tends to under-predict daytime ozone concentrations at rural and remote monitoring sites across the U.S. during the spring of 2016 whereas the predictions from the GEOS-Chem global model [137] were generally less biased.[138] During the summer of 2016 both models showed varying degrees of over prediction with GEOS-Chem showing somewhat greater over-prediction, compared to H–CMAQ. In view of those results, EPA examined the impacts of using GEOS-Chem as an alternative to H–CMAQ for providing boundary conditions for the final rule modeling.

For the lightning NO_X, biogenics, and GEOS-Chem sensitivity runs, EPA reran the proposal modeling using each of these inputs, individually. Results from these sensitivity runs indicate that each of the three updates provides an improvement in model performance. However, by far the greatest improvement in model performance is attributable to the use of GEOS-Chem. In view of these results EPA has included lightning NO_X emissions, updated biogenic emissions, and international transport from GEOS-Chem in the final rule air quality modeling. Details on the results of the individual sensitivity runs can be found in the Air Quality Modeling Final Rule TSD. For the air quality modeling supporting this final action, model performance based on days in 2016 with measured MDA8 ozone ≥60 ppb is considerably improved (*i.e.,* less bias and error) compared to the proposal modeling in nearly all regions of the U.S. For example, in the Upper Midwest, which includes monitoring sites along Lake Michigan, the normalized mean bias improved from a 19 percent under prediction to a 6.9 percent under prediction and in the Southwest region, which includes monitoring sites in Denver and Salt Lake City, normalized mean bias improved from a 13.6 percent under prediction to a 4.8 percent under prediction.[139] In all regions, the

[130] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[131] Guenther, A.B., 1997. Seasonal and spatial variations in natural volatile organic compound emissions. Ecol. Appl. 7, 34–45. *https://doi.org/10.1890/1051-0761(1997)007[0034:SASVIN]2.0.CO;2.* Guenther, A., Hewitt, C.N., Erickson, D., Fall, R.

[132] Kang D, Mathur R, Pouliot GA, Gilliam RC, Wong DC. Significant ground-level ozone attributed to lightning-induced nitrogen oxides during summertime over the Mountain West States. NPJ Clim Atmos Sci. 2020 Jan 30;3:6. doi: 10.1038/s41612–020–0108–2. PMID: 32181370; PMCID: PMC7075249.

[133] Jaffe DA, Cooper OR, Fiore AM, Henderson BH, Tonnesen GS, Russell AG, Henze DK, Langford AO, Lin M, Moore T. Scientific assessment of background ozone over the U.S.: Implications for air quality management. Elementa (Wash DC). 2018;6(1):56. doi: 10.1525/elementa.309. PMID: 30364819; PMCID: PMC6198683.

[134] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, N. Possiel, G. Pouliot, B. Timin, K.W. Appel, 2019. Global Sources of North American Ozone. Presented at the 18th Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 21–23, 2019.

[135] Mathur, R., Gilliam, R., Bullock, O.R., Roselle, S., Pleim, J., Wong, D., Binkowski, F., and 1 Streets, D.: Extending the applicability of the community multiscale air quality model to 2 hemispheric scales: motivation, challenges, and progress. In: Steyn DG, Trini S (eds) Air 3 pollution modeling and its applications, XXI. Springer, Dordrecht, pp 175–179, 2012.

[136] Boundary conditions are the concentrations of pollutants along the north, east, south, and west boundaries of the air quality modeling domain. Boundary conditions vary in space and time and are typically obtained from predictions of global or hemispheric models. Information on how boundary conditions were developed for the final rule modeling can be found in the Air Quality Modeling Final Rule TSD.

[137] I. Bey, D.J. Jacob, R.M. Yantosca, J.A. Logan, B.D. Field, A.M. Fiore, Q. Li, H.Y. Liu, L.J. Mickley, M.G. Schultz. Global modeling of tropospheric chemistry with assimilated meteorology: model description and evaluation. J. Geophys. Res. Atmos., 106 (2001), pp. 23073–23095, 10.1029/2001jd000807.

[138] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, G., N. Possiel, B. Timin, K.W. Appel, 2022. Meteorological and Emission Sensitivity of Hemispheric Ozone and $PM_{2.5}$. Presented at the 21st Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 17–19, 2022.

[139] A comparison of model performance from the proposal modeling to the final modeling for

Continued

normalized mean bias and normalized mean error statistics for high ozone days based on the final rule modeling are within the range of performance criteria benchmarks (*i.e.,* < ±15 percent for normalized mean bias and <25 percent for normalized mean error).[140] Additional information on model performance is provided in the Air Quality Modeling Final Rule TSD. In summary, EPA included emissions of lightning NO_X, as requested by commenters, and investigated and addressed concerns about model performance for the final rule modeling.

C. Emissions Inventories

The EPA developed emissions inventories to support air quality modeling for this final rule, including emissions estimates for EGUs, non-EGU point sources (*i.e.,* stationary 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. The 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.

Prior to air quality modeling, the emissions inventories were processed into a format that is appropriate for the air quality model to use. 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 4.9 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 document titled, ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform'' (Jan. 2023), hereafter known as the 2016v3 Emissions Modeling TSD. This TSD is available in the docket for this rule.[141]

1. Foundation Emissions Inventory Data Sets

The 2016v3 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 through 2022, in addition to data retained 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. The 2016v2 platform used to support the proposed action included updated data from the 2017 NEI along with updates to models and methods as compared to 2016v1. The 2016v3 platform includes updates to the 2016v2 platform implemented in response to comments along with other updates to the 2016v2 platform such as corrections and the incorporation of updated data sources that became available prior to the 2016v3 inventories being developed. Several commenters noted that the 2016v2 platform did not include NO_X emissions that resulted from lightning strikes. To address this, lightning NO_X emissions were computed and included in the 2016v3 platform.

For this final rule, the EPA developed emissions inventories for the base year of 2016 and the projected years of 2023 and 2026. The 2023 and 2026 inventories 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.[142] The 2016 emissions inventories for the U.S. primarily include data derived from the 2017 National Emissions Inventory (2017 NEI)[143] and data specific to the year of 2016. The following sections provide an overview of the construct of the 2016v3 emissions and projections. The fire emissions were unchanged between the 2016v2 and 2016v3 emissions platforms. For the 2016v3 platform, the biogenic emissions were updated to use the latest available versions of the Biogenic Emissions Inventory System and associated land use data to help address comments related to a degradation in model performance in the 2016v2 platform as compared to the 2016v1 platform. Details on the construction of the inventories are available in the 2016v3 Emissions Modeling TSD. Details on how the EPA responded to comments related to emissions inventories are available in the *RTC* document for this rule.

2. Development of Emissions Inventories for EGUs

a. EGU Emissions Inventories Supporting This Final Rule

Development of emissions inventories for 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 by the state, local, and tribal agencies. 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. Emissions data for EGUs that did not have data submitted to the NEI specific to the year 2016 were filled in with data from the 2017 NEI. For more information on the details of how the 2016 EGU emissions were developed and prepared for air quality modeling, see the 2016v3 Emissions Modeling TSD.

The EPA projected 2023 and 2026 baseline EGU emissions using the version 6—Updated 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-

individual monitoring sites can be found in the docket for this final rule.

[140] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[141] See 2016v3 Emissions Modeling TSD, also available at *https://www.epa.gov/air-emissions-modeling/2016v3-platform.*

[142] 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.

[143] *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-technical-support-document-tsd.*

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.[144] The EPA relied on the same model platform at final as it did at proposal, but made substantial updates to reflect public comments on near-term fossil fuel market price volatility and updated fleet information reflecting Summer 2022 U.S. Energy Information Agency (EIA) 860 data, unit-level comments, and additional updates to the National Electric Energy Data System (NEEDS) inventory.

The IPM version 6—Updated Summer 2021 Reference Case incorporated recent updates through the Summer of 2022 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 EIA's Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in Fall 2020 but updated in summer of 2022 to capture near-term price volatility and current market conditions. The inventory of EGUs provided as an input to the model was the NEEDS fall 2022 version and is available on EPA's website.[145] This version of NEEDS reflects announced retirements and under-construction new builds known as of early summer 2022. 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, NSR enforcement settlements, the final ELG Rule, 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 best available retrofit technology (BART) requirements. Documentation of IPM version 6 and NEEDS, along with updates, is in Docket ID No. EPA–HQ–OAR–2021–0668 and available online at *https://www.epa.gov/airmarkets/power-sector-modeling*. 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 adopted a similar approach to the CSAPR Update and the Revised CSAPR Update where it utilized historical data and an engineering analytics approach 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 starting with unit-level reported data and only making adjustments to reflect known baseline changes such as planned retirements and new builds (for the base case scenarios) and also identified mitigation strategies for determining state emissions budgets. In both the CSAPR Update and in this rule at Step 3, the EPA complemented that projected IPM EGU outlook with an 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 Final 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 document.

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 regional changes that are anticipated in response to market forces and fleet trends, the Engineering Analysis deliberately creates future estimates of the power sector where state estimates are limited to known changes. 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 the current analytic 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 the 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 determine that regardless of which EGU inventory is used, the 2023 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 one limited to current data and known changes (Engineering Analysis), the states that are linked to receptors at Steps 1 and 2 would be the same. This finding is consistent with the observation that EGUs are now less than

[144] Detailed information and documentation of EPA's Base Case, including all the 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.*

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

10 percent 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. 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 Ozone Transport Policy Analysis Final Rule TSD contains data on 2023 and 2026 AQ impacts of each dataset.

Comment: Some commenters express concern that using IPM for Step 1 and Step 2 captures generation shifting across state lines, which exceeds the EPA's authority. Moreover, the commenters suggest that the resulting proposed baseline EGU inventory may understate emissions levels as it projects economic retirements that are not yet announced or firm. Other commenters more generally allege that the EPA is using different modeling tools at different steps in its analysis, and this introduces confusion or uncertainty into the basis for the EPA's regulatory conclusions.

Response: The EPA believes the first aspect of this comment, in regards to its focus on generation shifting, is misguided in several ways. For Step 1 and Step 2, the EPA models no incremental generation shifting attributable to the implementation of an emissions control policy at Step 3. Rather, any generation patterns are merely a reflection of the model's projection of how regional load requirements will be met with the generation sources serving that region in the baseline. The EPA is not modeling any additional generation shifting, but merely capturing the expected generation dispatch under anticipated baseline market conditions. Electricity generated in one state regularly is transmitted across state boundaries and is used to serve load in other states; IPM is not incentivizing or requiring any additional generation transfer across state lines in this scenario but is merely projecting the pattern of this behavior in the future. Moreover, as noted previously, the EPA affirms its geographic findings at Step 2 (states contributing over 1 percent of the NAAQS to a downwind receptor) using historical data (engineering analysis) in a sensitivity analysis. These historical data reflect the actual generation patterns observed to meet regional load. Therefore, any suggestion by the commenter that the EPA's projected view of baseline grid dispatch is unreasonable, is mooted by the fact that the use of historical reported generation patterns produces the same result. Additionally, at the time of the proposal's analysis, the 2023 ozone season was still nearly two years away. Therefore, it was appropriate for EPA's modeling to project economic retirements as those retirements—which are regularly occurring—are often not firm or announced two years in advance. However, for this final rule, the 2023 analytic year was close enough to the period in which EPA was conducting its analysis that such retirements would likely be announced. Therefore, the EPA was able to incorporate those announced and firm retirements to occur in the 2023 year. Further, in recognition of this very near timeframe, we deactivated IPM's ability to project additional economic retirements for the 2023 year (reflecting the notion that any retirements occurring by 2023 would be known at this point). This adjustment further accommodates the commenters' concern that the baseline overstates generation shifting (driven by retirements) in the near term, and consequently understates emissions levels. Finally, with respect to comments that the EPA is using different modeling tools at different steps in the framework, we previously explained why these techniques are appropriate for the purposes at each step of the analysis, and they are not incompatible nor do they produce results so different as to call into question their reliability or the bases for our regulatory determinations (EPA notes that the nationwide projected ozone season total NO_X emissions vary by less than 1 percent in the 2023 analytic year). Nonetheless, we also observe that the effect of using engineering analytics to inform analysis at Steps 1 and 2 would tend to produce higher assumed emissions from EGUs in the baseline than IPM would project in 2026 and beyond and therefore only strengthen and further affirm the Step 1 and Step 2 geographic findings. EPA's use of different tools to project EGU scenarios is not inconsistent, but rather it is carefully explained as a deliberate measure taken to preserve—not introduce—consistency across each of the Steps in the 4-step framework. By using IPM at Step 1 and 2, EPA is selecting the more conservative approach for identifying the degree of nonattainment and geography of states contributing above 1 percent. By using Engineering Analytics at Step 3, EPA is selecting the more conservative value to codify into state-level budgets.

b. Impact of the Inflation Reduction Act on EGU Emissions

The EGU modeling used to construct the EGU emissions inventories used to inform the modeling projections for 2023 and 2026 was conducted prior to the passage of the Inflation Reduction Act (IRA), Public Law 117–169. The EPA did not have time to incorporate updated EGU projections reflecting the passage of the IRA into the primary air quality modeling for this final rule. However, the EPA was able to perform a sensitivity analysis reflecting the IRA in its EGU NO_X emissions inventories. The results from this scenario were run through AQAT and demonstrated that the status of states identified as linked at the 1 percent of NAAQS contribution threshold (based on the modeling and air quality analysis described in this section) would not change regardless of which inventory (with or without IRA) is used. This sensitivity analysis is presented in the Regulatory Impact Analysis accompanying this rule, and that discussion provides additional detail on the emissions consequences of including the IRA in a baseline EGU inventory. The air quality impact of including the IRA in EPA's emissions inventories and in its Step 3 scenarios is discussed in Appendix K of the Ozone Transport Policy Analysis Final Rule TSD.

The results of this analysis are not surprising and accord with what is generally understood to be the overall effect of the IRA over the short to long term. While the IRA is anticipated to have a potentially dramatic effect on reducing both GHG and conventional pollutant emissions from the power sector, it is likely to have a more substantial impact later in the forecast period (*i.e.,* beyond the attainment deadlines by which the emissions reductions under this final rule must occur). This timing reflects a realistic assessment of utilities', regulators', and transmission authorities' planning requirements associated with the addition of substantial new renewable and storage capacity to the grid, as well as the time needed to integrate that capacity and retire existing capacity. Additionally, the IRA incentives span a longer time period (for example, certain tax incentives for clean energy sources are available until the later of 2032 or the year in which power sector emissions are 75 percent below 2022 levels) and therefore there is no IRA-related deadline to build cleaner generation by 2026. Recent analysis by the Congressional Budget Office supports the finding that the majority of power sector EGU emissions reductions expected from the IRA occur well after the 2023 and 2026 analytic years relevant to the attainment dates and this rulemaking.[146] While the report focuses on CO_2 rather than NO_X, the drivers of the emissions reductions (primarily increased zero-emitting generation) would generally have a downward impact on both pollutants.

We note that important uncertainties remain at this time in the implementation of the IRA that further counsel against over-assuming short-term emissions reductions for purposes of this rule. The legislation provides economic incentives for shifting to cleaner forms of power generation but does not mandate emissions reductions through an enforceable regulatory program. The strength of those incentives will vary to some extent depending on other key market factors (such as the cost of natural gas or renewable energy technologies). Further, some incentives, such as tax credits for carbon capture and storage, could lead EGUs to remain in operation longer, which could in turn result in greater NO_X emissions, if those emissions are not also well controlled.

Nonetheless, while we find that the passage of the IRA does not affect the geography of the rule in terms of which states we identify as linked, the Agency is confident that the incentives toward clean technology provided in the IRA will, in the longer run beyond the 2015 ozone NAAQS attainment deadlines, facilitate ongoing EGU compliance with the emissions reduction requirements of this rule and will reduce costs borne by EGUs and their customers as the U.S. power sector transitions. As discussed in greater detail in section VI.B of this document, we have made several adjustments in the final rule to provide greater flexibility to EGU owners and operators to integrate this rule's requirements with and facilitate the accelerating transition to an overall cleaner electricity-generating sector, which the IRA represents. Despite the uncertainties inherent in the implementation of the IRA at this time, the EPA also has performed a sensitivity analysis on the final rule to confirm that our finding of no overcontrol is robust to a future with the IRA in effect.

3. Development of Emissions Inventories for Stationary Industrial Point Sources

Non-EGU point source emissions are mostly consistent with those in the proposal modeling except where they were updated in response to comments. Several commenters mentioned that point source emissions carried forward from 2014 NEI were not the best estimates of 2017 emissions. Thus, emissions sources in 2016v2 that had been projected from the 2014 NEI in the proposal were replaced with emissions based on the 2017 NEI. Point source emissions submitted to the 2016 NEI or to the 2016v1 platform development process specifically for the year 2016 were retained in 2016v3. Other 2016 non-EGU updates in 2016v3 include a few sources being moved to the EGU inventory, the addition of some control efficiency information for the year 2016, the replacement of most emissions projected from 2014 NEI with data from 2017 NEI, and the inclusion of point source data for solvent processes that had not been included in the 2016v2 non-EGU inventory.

The 2023 and 2026 non-EGU point source emissions were grown from 2016 to those years using factors based on the AEO 2022 and reflect emissions reductions due to known national and local rules, control programs, plant closures, consent decrees, and settlements that could be computed as reductions to specific units by July 2022.

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. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016, 2023 and 2026 based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast 2021 [147] data, the latest available version at the time the factors were developed. By basing the factors on the latest available Terminal Area Forecast that was released following the most significant pandemic impacts on the aviation sector, the reduction and rebound impacts of the pandemic on aircraft and ground support equipment were reflected in the 2023 and 2026 airport emissions.

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 2023, and 2026 with the fleet mix assumed to be constant throughout the period.

The EPA made multiple updates to point source oil and gas emissions in response to comments. For the final rule, the point source oil and gas emissions for 2016 were based on the 2016v2 point inventory except that most 2014 NEI-based emissions were replaced with 2017 NEI emissions. Additionally, in response to comments, state-provided emissions equivalent to those in the 2016v1 platform were used for Colorado, and some New Mexico emissions were replaced with data backcast from 2020 to 2016. To develop inventories for 2023 and 2026 for the final rule, the year 2016 oil and gas point source inventories were first projected to 2021 values based on actual historical production data, then those 2021 emissions were projected to 2023 and 2026 using regional projection factors based on AEO 2022 projections. This was an update from the proposal approach that used actual data only through the year 2019, because 2021 data were not yet available. NO_X and VOC reductions resulting from co-benefits of NSPS for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected, along with Natural Gas Turbine and Process Heater NSPS NO_X controls and Oil and Gas NSPS VOC controls. In some cases, year 2019 point source inventory data were used instead of the projected future year emissions except for the Western Regional Air Partnership (WRAP) states of Colorado, New Mexico, Montana, Wyoming, Utah, North Dakota, and South Dakota. The WRAP future year inventory [148] was used in these WRAP states in all future years except in New Mexico where the WRAP base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative code 20.2.50 [149] were also included.

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

[146] ''Emissions of Carbon Dioxide In the Electric Power Sector,'' Congressional Budget Office. December 2022. Available at *https://www.cbo.gov/publication/58860.*

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

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

[149] *https://www.srca.nm.gov/parts/title20/20.002.0050.html.*

developed the onroad mobile source emissions for states other than California using the 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 the 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 were developed based on emissions factors output from MOVES3 runs 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 those used to develop the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Prior to computing the final rule emissions, updates to some onroad inputs were made in response to comments and to implement corrections. Onroad mobile source emissions for California were consistent with the updated emissions data provided by the state for the final rule.

The 2023 and 2026 onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of those years. MOVES emissions factors for the years 2023 and 2026 were used. A comprehensive list of control programs included for onroad mobile sources is available in the 2016v3 Emissions Modeling TSD. Year 2023 and 2026 activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023 and 2026 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration. Because VMT for onroad mobile sources were substantially impacted by the pandemic and took about two years to rebound to pre-pandemic levels, in the 2016v3 platform no growth in VMT was implemented from 2019 to. The estimated 2021 VMT were then grown from 2021 to 2023 and 2026 using AEO 2022-based factors. Recent updates to inspection and maintenance programs in North Carolina and Tennessee were reflected in the MOVES inputs for the final rule modeling. The 2023 and 2026 onroad mobile emissions were computed within SMOKE by multiplying the respective emissions factors developed using MOVES with the year-specific activity data. Prior to computing the final rule emissions for 2023, the EPA made updates to some onroad inputs in response to comments and to implement corrections.

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 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 category 3 (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 and 2026 were incorporated into the projected emissions for CMV sources. The CMV emissions were split into emissions inventories from the larger 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 projected emissions for the years of 2023 and 2026 instead of 2023 and 2028. In addition, in response to comments, the EPA implemented an improved process for spatial allocating CMV emissions along state and county boundaries.

6. Development of Emissions Inventories for Other Nonroad Mobile Sources

The EPA developed nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) for 2016, 2023, and 2026 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 nonroad emissions for the final rule were unchanged from those at the proposal. 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 2016v3 Emissions Modeling TSD.

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 locomotive emissions were developed through the 2016v1 collaborative process and the year 2016 emissions are mostly consistent with those in the 2017 NEI. More information on the development of the Class I, Class II and III, and commuter rail line haul locomotive emissions is available in the 2016v3 Emissions Modeling TSD. The projected locomotive emissions for 2023 and 2026 were developed by applying factors to the 2016 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. The emission factors used for NO_X, PM10 and VOC for line haul locomotives in the analytic years were derived from trend lines based on historic line-haul emission factors from the period of 2007 through 2017 and extrapolated to 2023 and 2026.

7. Development of Emissions Inventories for Nonpoint Sources

For stationary nonpoint sources, some emissions in the 2016 base case emissions inventory come directly from the 2017 NEI, others were adjusted from the 2017 NEI to represent 2016 levels, and the remaining emissions including those from oil and gas, fertilizer, and solvents were computed specifically to represent 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 derived from 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 recent method to compute solvent VOC emissions was used.[150]

Where comments were provided about projected control measures or

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

changes in nonpoint source emissions, those inputs were first reviewed by the EPA. Those found to be based on reasonable data for affected emissions sources were incorporated into the projected inventories for 2023 and 2026 to the extent possible. Where possible, projection factors based on the AEO used data from AEO 2022, the most recent AEO at the time available at the time the inventories were developed. Federal regulations that impact the nonpoint sources were reflected in the inventories. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included along with solvent controls applicable within the ozone transport region. Details are available in the 2016v3 Emissions Modeling TSD.

Nonpoint oil and gas emissions inventories for many states were developed based on outputs from the 2017 NEI version of the EPA Oil and Gas Tool using activity data for year 2016. Production-related emissions data from the 2017 NEI were used for Oklahoma, 2016v1 emissions were used for Colorado and for Texas production-related sources to response to comments. Data for production-related nonpoint oil and gas emissions in the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming were obtained from the WRAP baseline inventory.[151] A California Air Resources Board-provided inventory was used for 2016 oil and gas emissions in California. Nonpoint oil and gas inventories for 2023 and 2026 were developed by first projecting the 2016 oil and gas inventories to 2021 values based on actual production data. Next, those 2021 emissions were projected to 2023 and 2026 using regional projection factors by product type based on AEO 2022 projections. A 2017–2019 average inventory was used for oil and natural gas exploration emissions in 2023 and 2026 except for California and in the WRAP states in which data from the WRAP future year inventory[152] were used. NO_X and VOC reductions that are co-benefits to the NSPS for RICE are reflected, along with Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls. The WRAP future year inventory was used for oil and natural gas production sources in 2023 and 2026 except in New Mexico where the WRAP Base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative Code 20.2.50 were included.

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 and 2026 analytic years. Where the EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in these analytic years, that site is excluded from further analysis under this rule.

In the proposed rule, the EPA applied the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS.[153] *See* 86 FR 23078–79. The 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*.[154] 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.[155]

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 monitoring sites that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those monitoring sites that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that site. The variability in air quality was determined by evaluating the ''maximum'' future design value at each monitoring site 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 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.[156] 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 rule, the EPA assessed the magnitude of the projected maximum design values for 2023 and 2026 at each monitoring site 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*.[157] That is,

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

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

[153] *See* 86 FR 23078–79.

[154] 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)).

[155] *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).

[156] 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.

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

monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.[158]

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 previously, 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.[159]

Comment: The EPA received comments claiming that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on the EPA's modeling for the proposed action are currently measuring nonattainment based on data from 2020 and 2021. One commenter requested that the EPA determine whether its past modeling tends to overestimate or underestimated actual observed design values. If EPA finds that the agency's model tends to underestimate future year design values, the commenter requests that EPA re-run its ozone modeling, incorporating parameters that account for this tendency.

Response: In response to comments, the EPA compared the projected 2023 design values based on the proposal modeling to recent trends in measured data. As a result of this analysis, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors). It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has also developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites.

Specifically, the EPA has identified monitoring sites with measured 2021 and preliminary 2022 design values *and* 4th high maximum daily 8-hour average (MDA8) ozone in both 2021 and 2022 (preliminary data) that exceed the NAAQS, although projected to be in attainment in 2023, as having the greatest risk of continuing to have a problem attaining the standard in 2023. These criteria sufficiently consider measured air quality data so as to avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. Moreover, 2023 is so near in time that recent measured ozone levels can be used to reasonably project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action, while also identifying all transport receptors.

For purposes of this action, we treat these violating monitors as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment such that they should be considered nonattainment receptors. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if an area may be technically in attainment, we have reliable information indicating that there is an identified risk that attainment will not in fact be achieved.

[158] 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–2021–0668 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.* EPA is not applying the suggested analytical approaches in that memorandum in this rule, nor would those approaches be appropriate in light of currently available data. 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.

[159] See *https://www.epa.gov/air-trends/air-quality-design-values* for design value reports. At the time of this action, the most recent reports available are for the calendar year 2021.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring taking final action on that state's SIP submittal. This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

E. Methodology for Projecting Future Year Ozone Design Values

Consistent with the 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 and 2026. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values [160] 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 final rule is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used to project average and maximum design values in 2023 and 2026.

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 and 2026 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 [161] surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.[162] However, the guidance also notes that an alternative array of grid cells may be used in certain situations where local topographic or geographical feature (*e.g.,* a large water body or a significant elevation change) may influence model response.

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 × 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, the 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).[163] Specifically, in the WRF meteorological model those grid cells that are greater than 50 percent 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 limited due to the presence of overwater meteorology. Thus, for our modeling the EPA projected average and maximum design values at individual monitoring sites based on both the ''3 × 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 and 2026 design values using both the ''3 × 3'' and ''no-water'' approaches are provided in the docket for this final rule. For this final rule, the EPA is relying upon design values based on the ''no water'' approach for identifying nonattainment and maintenance receptors.[164]

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.[165] 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 2021, which are the most recent official measured design values at the time of this final rule. As noted earlier, the Agency is identifying nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current

[160] 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.

[161] As noted in this section, each model grid cell is 12 x 12 km.

[162] The relative response factor represents the change in ozone at a given site. To calculate the RRF, the 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) average ozone concentration and the future year (*e.g.,* 2023 model run) average ozone concentration represents the relative response factor.

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

[164] Using design values from the ''3 × 3'' approach, the maintenance-only receptor at site 550590019 in Kenosha County, WI would become a nonattainment receptor because the average design value with the ''3 × 3'' approach is 72.0 ppb versus 70.8 ppb with the ''no water'' approach. In addition, the maintenance-only receptor at site 090099002 in New Haven County, CT would become a nonattainment receptor using the ''3 × 3'' approach because the average design value with the ''3 × 3'' approach is 71.2 ppb versus 70.5 ppb with the ''no water'' approach.

[165] 40 CFR part 50, appendix P—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

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 (*i.e.,* ozone design values below the level of the 2015 ozone NAAQS) 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, 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 the 2015 ozone NAAQS as part of this final rule.[166]

Table IV.D–1 contains the 2016-centered[167] base period average and maximum 8-hour ozone design values, the 2023 base case average and maximum design values and the measured 2021 design values for the sites that are projected to be nonattainment receptors in 2023. Table IV.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 Air Quality Modeling Final Rule TSD.

TABLE IV.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
060650016	CA	Riverside	79.0	80.0	72.2	73.1	78
060651016	CA	Riverside	99.7	101.0	91.0	92.2	95
080350004	CO	Douglas	77.3	78	71.3	71.9	83
080590006	CO	Jefferson	77.3	78	72.8	73.5	81
080590011	CO	Jefferson	79.3	80	73.5	74.1	83
090010017	CT	Fairfield	79.3	80	71.6	72.2	79
090013007	CT	Fairfield	82.0	83	72.9	73.8	81
090019003	CT	Fairfield	82.7	83	73.3	73.6	80
481671034	TX	Galveston	75.7	77	71.5	72.8	72
482010024	TX	Harris	79.3	81	75.1	76.7	74
490110004	UT	Davis	75.7	78	72.0	74.2	78
490353006	UT	Salt Lake	76.3	78	72.6	74.2	76
490353013	UT	Salt Lake	76.5	77	73.3	73.8	76
551170006	WI	Sheboygan	80.0	81	72.7	73.6	72

TABLE IV.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
040278011	AZ	Yuma	72.3	74	70.4	72.1	67
080690011	CO	Larimer	75.7	77	70.9	72.1	77
090099002	CT	New Haven	79.7	82	70.5	72.6	82
170310001	IL	Cook	73.0	77	68.2	71.9	71
170314201	IL	Cook	73.3	77	68.0	71.5	74
170317002	IL	Cook	74.0	77	68.5	71.3	73
350130021	NM	Dona Ana	72.7	74	70.8	72.1	80
350130022	NM	Dona Ana	71.3	74	69.7	72.4	75
350151005	NM	Eddy	69.7	74	69.7	74.1	77
350250008	NM	Lea	67.7	70	69.8	72.2	66
480391004	TX	Brazoria	74.7	77	70.4	72.5	75
481210034	TX	Denton	78.0	80	69.8	71.6	74
481410037	TX	El Paso	71.3	73	69.8	71.4	75
482010055	TX	Harris	76.0	77	70.9	71.9	77
482011034	TX	Harris	73.7	75	70.1	71.3	71
482011035	TX	Harris	71.3	75	67.8	71.3	71
530330023	WA	King	73.3	77	67.6	71.0	64
550590019	WI	Kenosha	78.0	79	70.8	71.7	74
551010020	WI	Racine	76.0	78	69.7	71.5	73

[166] In addition, there are 71 monitoring sites in California with projected 2023 maximum design values above the NAAQS. With two exceptions, as described in section IV.F of this document, the Agency is not making a determination in this action that these monitors are ozone transport receptors. The two exceptions are the two monitoring sites that represent air quality impacts to lands of the Morongo and Pechanga tribes. As explained in footnote 110 supra, we treat these as transport receptors that are impacted by emissions from California.

[167] 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.

In total, in the 2023 base case there are a total of 33 projected modeling-based receptors nationwide including 14 nonattainment receptors in 9 different counties and 19 maintenance-only receptors in 13 additional counties (Harris County, TX, has both nonattainment and maintenance-only receptors).[168] Of the 14 nonattainment receptors in 2023, 7 remain nonattainment receptors, 5 are projected to become maintenance-only receptors and 2 are projected to be in attainment in 2026. Of the 19 maintenance-only receptors in 2023, 7 are projected to remain maintenance-only receptors and 12 are projected to be in attainment in 2026. The projected average and maximum design values in 2026 for all receptors are included in the Air Quality Modeling Final Rule TSD.

Comment: EPA received comments saying that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on EPA's modeling for the proposed rule are currently measuring nonattainment. Because 2023 is only a year later than the most recent measured data some commenters said that EPA should give greater weight to measured data when identifying downwind receptors.

Response: Based on an analysis of model projections for 2023 and recent trends in measured data, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors).[169] Specifically, the EPA believes that monitoring sites with measured design values *and* 4th high maximum daily 8-hour average (MDA8) ozone based on 2021 *and* preliminary 2022 data have the greatest risk of continuing to have a problem attaining the standard in 2023, even when the modeling projects these sites will attain. These criteria are sufficiently conservative that we avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. We do not apply this methodology for the 2026 analytic year, because that year is sufficiently farther in the future that we do not believe there would be a reasonable basis to supplement our modeling analysis with this ''violating monitor'' methodology. By comparison, 2023 is so near in time that recent measured ozone levels can be used reasonably to project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action. The monitoring sites that meet these criteria, along with the corresponding measured and modeled data, are provided in Table IV.D–3.

For purposes of this action, we will treat these sites as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment that they should be considered nonattainment receptors for purposes of this final rule. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

In this action, we identify ''violating monitor'' maintenance-only receptors for purposes of more firmly establishing that the states we have otherwise identified as linked at Step 2 in our modeling-based methodology can indeed be reasonably anticipated to be linked to air quality problems in downwind states in 2023 for reasons that extend beyond that methodology. In this sense, this approach is ''confirmatory'' and does not alter the geography of the final rule compared to the application of the modeling-based receptor definitions used at proposal. Rather, it strengthens the analytical basis for our Step 2 findings by establishing that many upwind states covered in this action are also projected to contribute above 1 percent of the NAAQS to these types of receptors. For purposes of this final rule, we will not finalize FIPs for any states that this analysis indicates contribute greater than 1 percent of the NAAQS only to a ''violating monitor'' receptor. Our analysis suggests this would be the case for two states, Kansas and Tennessee (see section IV.F of this document).[170] We are making no final decisions with respect to these states in this action and intend to address these states in a subsequent action.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40070010	AZ	Gila	67.9	69.5	77	76	75	74

[168] 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 noted in the proposed rule, 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 final rule.

[169] In addition, we note that comparing the projected 2023 maximum design values at modeling-based receptors listed in Table IV.D–1 and Table IV.D–2 to the 2021 design values measured at these sites indicates that the projected maximum values are lower than the measured data at most receptors. These differences are particularly evident at receptors in coastal Connecticut and in Denver. (See Air Quality Modeling Final Rule TSD for details).

[170] We have not conducted an analysis in this action to determine whether violating-monitor receptors may exist in California.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS—Continued

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40130019	AZ	Maricopa	69.8	70.0	75	77	78	76
40131003	AZ	Maricopa	70.1	70.7	80	80	83	78
40131004	AZ	Maricopa	70.2	70.8	80	81	81	77
40131010	AZ	Maricopa	68.3	69.2	79	80	80	78
40132001	AZ	Maricopa	63.8	64.1	74	78	79	81
40132005	AZ	Maricopa	69.6	70.5	78	79	79	77
40133002	AZ	Maricopa	65.8	65.8	75	75	81	72
40134004	AZ	Maricopa	65.7	66.6	73	73	73	71
40134005	AZ	Maricopa	62.3	62.3	73	75	79	73
40134008	AZ	Maricopa	65.6	66.5	74	74	74	71
40134010	AZ	Maricopa	63.8	66.9	74	76	77	75
40137020	AZ	Maricopa	67.0	67.0	76	77	77	75
40137021	AZ	Maricopa	69.8	70.1	77	77	78	75
40137022	AZ	Maricopa	68.2	69.1	76	78	76	79
40137024	AZ	Maricopa	67.0	67.9	74	76	74	77
40139702	AZ	Maricopa	66.9	68.1	75	77	72	77
40139704	AZ	Maricopa	65.3	66.2	74	77	76	76
40139997	AZ	Maricopa	70.5	70.5	76	79	82	76
40218001	AZ	Pinal	67.8	69.0	75	76	73	77
80013001	CO	Adams	63.0	63.0	72	77	79	75
80050002	CO	Arapahoe	68.0	68.0	80	80	84	73
80310002	CO	Denver	63.6	64.8	72	74	77	71
80310026	CO	Denver	64.5	64.8	75	77	83	72
90079007	CT	Middlesex	68.7	69.0	74	73	78	73
90110124	CT	New London	65.5	67.0	73	72	75	71
170310032	IL	Cook	67.3	69.8	75	75	77	72
170311601	IL	Cook	63.8	64.5	72	73	72	71
181270024	IN	Porter	63.4	64.6	72	73	72	73
260050003	MI	Allegan	66.2	67.4	75	75	78	73
261210039	MI	Muskegon	67.5	68.4	74	79	75	82
320030043	NV	Clark	68.4	69.4	73	75	74	74
350011012	NM	Bernalillo	63.8	66.0	72	73	76	74
350130008	NM	Dona Ana	65.6	66.3	72	76	79	78
361030002	NY	Suffolk	66.2	68.0	73	74	79	74
390850003	OH	Lake	64.3	64.6	72	74	72	76
480290052	TX	Bexar	67.1	67.8	73	74	78	72
480850005	TX	Collin	65.4	66.0	75	74	81	73
481130075	TX	Dallas	65.3	66.5	71	71	73	72
481211032	TX	Denton	65.9	67.7	76	77	85	77
482010051	TX	Harris	65.3	66.3	74	73	83	72
482010416	TX	Harris	68.8	70.4	73	73	78	71
484390075	TX	Tarrant	63.8	64.7	75	76	76	77
484391002	TX	Tarrant	64.1	65.7	72	77	76	80
484392003	TX	Tarrant	65.2	65.9	72	72	74	72
484393009	TX	Tarrant	67.5	68.1	74	75	75	75
490571003	UT	Weber	69.3	70.3	71	74	77	71
550590025	WI	Kenosha	67.6	70.7	72	73	72	71
550890008	WI	Ozaukee	65.2	65.8	71	72	72	72

* 2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to the EPA's Air Quality System (AQS), as of January 3, 2023.

F. 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[171] to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the

[171] 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.

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. 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 runs, 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 2016v3 emissions modeling platform (EPA did not model the contributions from individual tribes);
- 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.[172]

This same approach was applied to calculate contribution metric values at individual monitoring sites for 2026.[173]

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 final rule. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the Air Quality Modeling Final Rule TSD. The EPA's response to comments on the method for calculating the contribution metric can be found in the *RTC* document for this final rule.

The largest contribution from each state that is the subject of this rule to modeled 8-hour ozone nonattainment and maintenance receptors in downwind states in 2023 and 2026 are provided in Table IV.F–1 and Table IV.F–2, respectively. The largest contribution from each state to a ''violating monitor'' maintenance-only receptor is provided in Table IV.F–3.

TABLE IV.F–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	0.75	0.65
Arizona	0.54	1.69
Arkansas	0.94	1.21
California	35.27	6.31
Colorado	0.14	0.18
Connecticut	0.01	0.01
Delaware	0.44	0.56
District of Columbia	0.03	0.04
Florida	0.50	0.54
Georgia	0.18	0.17
Idaho	0.42	0.41
Illinois	13.89	19.09

[172] 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. The monitoring site in Seattle, King County, Washington (530330023), was the only receptor which did not meet this criterion.

[173] 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 IV.F–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Indiana	8.90	10.03
Iowa	0.67	0.90
Kansas	0.46	0.52
Kentucky	0.84	0.79
Louisiana	9.51	5.62
Maine	0.02	0.01
Maryland	1.13	1.28
Massachusetts	0.33	0.15
Michigan	1.59	1.56
Minnesota	0.36	0.85
Mississippi	1.32	0.91
Missouri	1.87	1.39
Montana	0.08	0.10
Nebraska	0.20	0.36
Nevada	1.11	1.13
New Hampshire	0.10	0.02
New Jersey	8.38	5.79
New Mexico	0.36	1.59
New York	16.10	11.29
North Carolina	0.45	0.66
North Dakota	0.18	0.45
Ohio	2.05	1.98
Oklahoma	0.79	1.01
Oregon *	0.46	0.31
Pennsylvania	6.00	4.36
Rhode Island	0.04	0.01
South Carolina	0.16	0.18
South Dakota	0.05	0.08
Tennessee	0.60	0.68
Texas	1.03	4.74
Utah	1.29	0.98
Vermont	0.02	0.01
Virginia	1.16	1.76
Washington	0.16	0.09
West Virginia	1.37	1.49
Wisconsin	0.21	2.86
Wyoming	0.68	0.67

TABLE IV.F–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	0.20	0.69
Arizona	0.44	1.34
Arkansas	0.53	1.16
California	34.03	6.16
Colorado	0.04	0.17
Connecticut	0.00	0.01
Delaware	0.43	0.41
District of Columbia	0.03	0.02
Florida	0.46	0.17
Georgia	0.13	0.16
Idaho	0.27	0.36
Illinois	0.63	13.57
Indiana	1.06	8.53
Iowa	0.14	0.62
Kansas	0.14	0.42
Kentucky	0.79	0.76
Louisiana	4.57	9.37

TABLE IV.F–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Maine	0.00	0.01
Maryland	1.06	0.92
Massachusetts	0.06	0.31
Michigan	1.39	1.47
Minnesota	0.15	0.32
Mississippi	0.29	1.15
Missouri	0.29	1.68
Montana	0.06	0.07
Nebraska	0.09	0.19
Nevada	0.67	0.90
New Hampshire	0.01	0.09
New Jersey	8.10	7.04
New Mexico	0.35	0.46
New York	12.65	12.34
North Carolina	0.40	0.42
North Dakota	0.09	0.17
Ohio	1.95	1.93
Oklahoma	0.19	0.74
Oregon *	0.26	0.41
Pennsylvania	5.47	4.94
Rhode Island	0.00	0.03
South Carolina	0.14	0.15
South Dakota	0.03	0.04
Tennessee	0.24	0.54
Texas	0.48	4.34
Utah	1.05	0.81
Vermont	0.01	0.02
Virginia	1.09	1.10
Washington	0.10	0.14
West Virginia	1.36	1.34
Wisconsin	0.17	0.18
Wyoming	0.40	0.59

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Alabama	0.79
Arizona	1.62
Arkansas	1.16
California	6.97
Colorado	0.39
Connecticut	0.17
Delaware	0.42
District of Columbia	0.03
Florida	0.50
Georgia	0.31
Idaho	0.46
Illinois	16.53
Indiana	9.39
Iowa	1.13
Kansas	0.82
Kentucky	1.57
Louisiana	5.06
Maine	0.02
Maryland	1.14
Massachusetts	0.39
Michigan	3.47

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE ''VIOLATING MONITOR'' MAINTENANCE-ONLY RECEPTORS—Continued

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Minnesota	0.64
Mississippi	1.02
Missouri	2.95
Montana	0.12
Nebraska	0.43
Nevada	1.11
New Hampshire	0.10
New Jersey	8.00
New Mexico	0.34
New York	12.08
North Carolina	0.65
North Dakota	0.35
Ohio	2.25
Oklahoma	1.57
Oregon *	0.36
Pennsylvania	5.20
Rhode Island	0.08
South Carolina	0.23
South Dakota	0.12
Tennessee	0.86
Texas	3.83
Utah	1.46
Vermont	0.03
Virginia	1.39
Washington	0.11
West Virginia	1.79
Wisconsin	5.10
Wyoming	0.42

* Does not include California monitoring sites.

2. Application of Contribution Screening Threshold

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 Air Quality Modeling Final Rule TSD.

The EPA applies an air quality screening threshold of 1 percent of the NAAQS, which has been used since the CSAPR rulemaking, including in the CSAPR Update, the Revised CSAPR Update, and numerous actions evaluating states' transport SIP submittals. The explanation for how this value was originally derived is available in the CSAPR rulemaking from 2011. *See* 76 FR 48208, 48237–38. As originally explained there, the application of a relatively low threshold is intended to capture a relatively large percentage of the contribution from upwind states to downwind receptors in light of the regional-scale, collective contribution problem associated with both ozone and $PM_{2.5}$ NAAQS. *Id.* The Agency also explained that the use of a higher threshold in transport rules prior to CSAPR was based on single-day maximum contribution, whereas in CSAPR (and continuing in subsequent rules including this one), the Agency uses a more robust, average contribution metric over multiple days. Thus, it was not the case that 1 percent of NAAQS was substantially more stringent than that prior approach. *Id.* at 48238. In the 2016 CSAPR Update, the EPA reviewed the 1 percent threshold (as coupled with multi-day averaging) and determined it was appropriate to continue to apply this threshold. The EPA compared the 1 percent threshold to a 0.5 percent of NAAQS threshold and a 5 percent of NAAQS threshold. The EPA found that the lower threshold did not capture appreciably more upwind state contribution compared to the 1 percent threshold, while the 5 percent threshold allowed too much upwind state contribution to drop out from further analysis.[174] The EPA continues to observe that nonattainment and maintenance receptors identified at Step 1 are impacted collectively by emissions from numerous upwind contributors. Therefore, application of a low, uniform screening threshold allows the EPA to identify upwind states that share a responsibility under the interstate transport provision to eliminate their significant contribution.

As we explained at proposal, 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.[175] (The memorandum also indicated that any

[174] *See* Final CSAPR Update Air Quality Modeling TSD, at 27–30 (EPA–HQ–OAR–2015–0596–0144). *See also* 86 FR 23054, 23085.

[175] August 2018 memo at 4.

higher alternative threshold, such as 2 ppb, would likely not be appropriate.) The EPA nonetheless proposed to fulfill its role under CAA section 110(c) in promulgating FIPs to directly implement good neighbor requirements, and in this role, proposed retaining use of the 1 percent threshold for all states. We noted that in several documents proposing transport SIP disapprovals, *see, e.g.,* 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), we explained that our experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds led the Agency to 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.

We went on to explain that the 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. Using multiple different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns.[176] The application of different thresholds at Step 2 has the potential to result in inconsistent determination 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. We explained that while 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 alternative thresholds would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This could create significant equity and consistency problems among states.

The EPA further proposed that, in promulgating FIPs to address these obligations on a nationwide scale, national ozone transport policy would not be well-served by applying a single, less stringent threshold 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 noted at proposal that while this 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. Considering the core statutory objective of ensuring elimination of *all* significant contribution to nonattainment or interference of the NAAQS in downwind states and the broad, regional nature of the collective contribution problem with respect to ozone, EPA could not identify a compelling policy imperative to move to a 1 ppb threshold.

In the proposal, we also found 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 protective ozone NAAQS) to be an important consideration. 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 protective NAAQS.

The Agency also questioned whether it would 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 the possibility of an alternative threshold in the August 2018 memorandum, the EPA concluded in the proposal that our experience and further evaluation since the issuance of that memo has revealed substantial programmatic and policy difficulties in attempting to implement this approach, and therefore we proposed to apply the 1 percent of NAAQS threshold.

Comment: Many commenters disagreed with our proposal to continue using a 1 percent of NAAQS threshold. They argued that the EPA was reversing course from its policy as articulated in the August 2018 memorandum and that the EPA was now bound to use a 1 ppb threshold rather than 1 percent of NAAQS, even in promulgating a FIP rather than evaluating SIPs. Commenters further argued that a 1 ppb threshold would be more consistent with the EPA's ''significant impact level'' (SIL) guidance related to implementing prevention of significant deterioration (PSD) permitting requirements. They argued that the 1 percent threshold was below precision limits of regulatory ozone monitors, and they argued it was within the ''margin of error'' of the EPA's modeling.

Response: The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS threshold at Step 2 in this action to determine which states contribute to identified nonattainment and maintenance receptors. This approach ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. We do not agree that this approach is inconsistent with or a reversal in policy from the August 2018 memorandum, which only suggested that states in the development of their SIPs ''may'' be able to establish that 1 ppb could be an appropriate alternative threshold. The EPA has been consistent in that memorandum, and since that time, that final determinations on alternative thresholds would be made through rulemaking action, as the EPA is taking here.

The August 2018 memorandum made clear that the Agency had substantial doubts that any threshold greater than 1 ppb (such as 2 ppb) would be acceptable, and the Agency is affirming that a threshold higher than 1 ppb would not be justified under any circumstance for purposes of this action. No commenter credibly provided a basis for using a threshold even higher than 1 ppb, and so this issue is primarily limited to the difference between a 0.7 ppb threshold (the 1 percent of the NAAQS threshold discussed previously in this section) and a 1.0 ppb threshold. Therefore, before proceeding in responding to these comments, we note that this issue is only relevant to a small number of states whose contributions to any receptor are above 1 percent of the NAAQS but lower than 1 ppb. Under the 2016v3 modeling of 2023 being used in this final rule, the states in this rule with contributions that fall between 0.70 ppb and 1 ppb are Alabama, Kentucky, and Minnesota. Similarly, the EPA applies the 1 percent threshold in its 2026 modeling projections to determine if any states will not be linked to an ozone receptor by that year, and therefore should not be subject to the more stringent requirements that take effect in 2026. The states in this rule in that year with contribution between 0.70 ppb and 1 ppb are

[176] 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.

Kentucky, Nevada, and Oklahoma. For all other states covered in this action, at least one linkage exists in 2023 (and, as relevant, in 2026) that is greater than 1 ppb, and therefore the question of whether the EPA must recognize a 1 ppb threshold would not have a dispositive effect on the regulatory determination being made at Step 2.

The 1 percent of the NAAQS threshold is consistent with the Step 2 approach that the EPA applied in CSAPR for the 1997 ozone NAAQS and has subsequently been applied in the CSAPR Update and Revised CSAPR Update when evaluating determining interstate transport obligations for the 2008 ozone NAAQS. The EPA continues to find 1 percent of the ozone NAAQS to be an appropriate threshold. For ozone, as the EPA found in CAIR, CSAPR, and the CSAPR Update, a portion of the nonattainment and maintenance problems in the U.S. results from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and other sources. The EPA's analysis shows that the ozone transport problem being analyzed in this rule is still the result of the collective impacts of emissions from multiple upwind contributors. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution (to the extent found ''significant'' at Step 3) to the downwind nonattainment and maintenance problems to which they collectively contribute. Where a great number of geographically dispersed emissions sources contribute to a downwind air quality problem, which is the case for ozone, EPA believes that, in the context of CAA section 110(a)(2)(D)(i)(I), a state-level threshold of 1 percent of the NAAQS is a reasonably small enough value to identify only the greater-than-de minimis contributors yet is not so large that it unfairly focuses attention for further action only on the largest single or few upwind contributors. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 86 FR 23054, 23085; 81 FR 74504, 74518; 76 FR 48208, 48237–38.

Further, the EPA notes that the role of the Step 2 threshold is limited and just one step in the larger 4-Step Framework. It serves to screen in states for further evaluation of emissions control opportunities applying a multifactor analysis at Step 3. Thus, as the Supreme Court has recognized, the contribution threshold essentially functions to exclude states with ''*de miminis*'' impacts. *EME Homer City,* 572 U.S. 489, 500.

Comments related to the August 2018 memorandum argued that the EPA legally committed itself to approving SIP submissions from states with contributions below 1 ppb and so now the EPA must apply that threshold in this FIP action. (Comments regarding this issue as related to the EPA's action on SIPs is addressed in that rulemaking and is beyond the scope of this action.) This is not what the memorandum said. The memorandum merely provided an analysis regarding ''the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states.'' [177] It interpreted ''that information to make recommendations about what thresholds *may* be appropriate for use in'' SIP submissions (emphasis added).[178] Specifically, the August 2018 memorandum said, ''Because the amount of upwind collective contribution capture with the 1 percent and the 1 ppb thresholds is *generally comparable, overall, we believe it may be* reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold, at Step 2 of the 4-step framework in developing their SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS'' (emphasis added).[179] Thus, the text of the August 2018 memorandum in no way committed that the EPA would be using a 1 ppb threshold going forward either in its evaluation of SIPs or in promulgating a FIP. The August 2018 memorandum indicated that ''[f]ollowing these recommendations does not ensure that EPA will approve a SIP revision in all instances where the recommendations are followed, as the guidance may not apply to the facts and circumstances underlying a particular SIP. Final decisions by the EPA to approve a particular SIP revision will only be made based on the requirements of the statute and will only be made following an air agency's final submission of the SIP revision to the EPA, and after appropriate notice and opportunity for public review and comment.'' [180] Further, the August 2018 memorandum said that ''EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.'' [181] The memorandum said nothing regarding what threshold the EPA would apply if promulgating a FIP.

As explained in the SIP disapproval action and again here, the EPA finds it would not be sound policy to apply an alternative contribution threshold or thresholds to one or more states within the 4-step interstate transport framework for the 2015 ozone NAAQS. However, the EPA disagrees with commenters' claims that the agency has reversed course on applying the August 2018 memorandum, because the memorandum never adopted a view that the use of 1 ppb or other alternative thresholds would in fact be acceptable. Although the EPA said at proposal that the EPA may rescind the guidance in the future, we took comment on the subject and also stated, ''EPA is not at this time rescinding the August 2018 memorandum.'' [182] The EPA is not formally rescinding the August 2018 memorandum in this action or at this time. However, it is not required that agencies must ''rescind'' a memorandum or guidance the moment it becomes outdated or called into question. The August 2018 memorandum was not issued through notice-and-comment rulemaking and is not binding on the Agency or other parties. While the *willingness* of the Agency as expressed in that memorandum to entertain the possibility of an alternative threshold of 1 ppb may be considered a kind of policy position, agencies may change their non-binding policies without going through notice and comment rulemaking. *Catawba County* v. *EPA,* 571 F.3d 20, 34 (D.C. Cir. 2009). In this case, we went through notice and comment rulemaking on this topic in the SIP-disapproval action (88 FR 9336) and here, even though the August 2018 memorandum was issued without such opportunity for public input. We further address the basis for the consistent use of a 1 percent of NAAQS threshold and summarize our conclusions under the *FCC* v. *Fox* factors below.

We continue to believe, as set forth in our proposed action, that national ozone transport policy is not well served by

[177] August 2018 memorandum, at 1.

[178] *Id.*

[179] *Id.* at 4.

[180] *Id.* at 1.

[181] *Id.*

[182] 87 FR 9545, 9551 (Feb. 22, 2022) (Alabama, Mississippi, Tennessee); 87 FR 9498, 9510 (Feb. 22, 2022) (Kentucky); 87 FR 9838, 9844 (Feb. 22, 2022) (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin); 87 FR 9798, 9807, 9813, 9820 (Feb. 22, 2022) (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9533, 9542 (Feb. 22, 2022) (Missouri); 87 FR 31470, 31479 (May 24, 2022) (Utah); 87 FR 31495, 31504 (May 24, 2022) (Wyoming); 87 FR 31485, 31490 (May 24, 2022) (Nevada).

allowing for less protective thresholds than 1 percent of the NAAQS at Step 2. Furthermore, the EPA disagrees with commenters who suggest that national consistency is an inappropriate consideration in the context of interstate ozone transport. The Good Neighbor provision, CAA section 110(a)(2)(D)(i)(I), requires to a unique degree of concern for consistency, parity, and equity across state lines.[183] For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Based on the EPA's review of good neighbor SIP submissions to-date and after further consideration of the policy implications of attempting to recognize an alternative Step 2 threshold for certain states, the Agency concludes that the attempted use of different thresholds at Step 2 with respect to the 2015 8-hour ozone NAAQS raises substantial policy consistency and practical implementation concerns. The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations based solely on the strength of a state's SIP submission at Step 2 of the 4-step interstate transport framework. The steps of the analysis that lead up to evaluating emissions reductions opportunities to address states' significant contribution at Step 3 should be applied on a consistent basis. 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 and could lead to ineffective or inefficient approaches to eliminating significant contribution.

One commenter suggested the EPA could address this potentially inequitable outcome by simply adopting a 1 ppb contribution threshold for all states. However, the August 2018 memorandum did not conclude that 1 ppb would be appropriate for all states and the EPA does not view that conclusion to be supported at present. The EPA recognized in the August 2018 memorandum that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold for every state. 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 memorandum; in the EPA's 2016v2 modeling, the amount lost is 5 percent; in the EPA's 2016v3 modeling used for final, the amount lost is also 5 percent). Further, this logic has no end point. A similar observation could be made with respect to any incremental change. For example, should the EPA next recognize a 1.2 ppb threshold because that would only cause some small additional loss in capture of upwind state contribution as compared to 1 ppb? If the only basis for moving to a 1 ppb threshold is that it captures a ''similar'' (but actually smaller) amount of upwind contribution, then there is no basis for moving to that threshold at all. Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference with maintenance of the NAAQS in other states and the broad, regional nature of the collective contribution problem with respect to ozone, we continue to find no compelling policy reason to adopt a new threshold for all states of 1 ppb.

Nor have commenters explained why use of a 1 ppb threshold would be appropriate under the more protective 2015 ozone NAAQS when a 1 percent of the NAAQS contribution threshold has been used for less protective ozone NAAQS. To illustrate, a state contributing greater than 0.75 ppb but less than 1 ppb to a receptor under the 2008 ozone NAAQS was ''linked'' at Step 2,[184] but if a 1 ppb threshold were used for the 2015 ozone NAAQS then that same state would *not* be ''linked'' to a receptor at Step 2 under a NAAQS that is set to be *more* protective of human health and the environment. Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which all used the 1 percent of the NAAQS for less protective ozone NAAQS), is an important consideration. We affirm our view in CSAPR that continuing to use a 1 percent of NAAQS approach ensures that if 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. *See* 76 FR 48208, 48237–38.

We note further that application of a 1 percent of NAAQS threshold has been the EPA's consistent approach in each of our notice-and-comment rulemakings beginning with CSAPR and continuing with the CSAPR Update, the Revised CSAPR Update, and numerous actions on ozone transport SIP submissions. In each case, the 1 percent of the NAAQS threshold was subject to rigorous vetting through public comment and the Agency's response to those comments, including through the use of analytical evaluations of alternative thresholds. *See, e.g.,* 81 FR 74518–19. By contrast, the August 2018 memorandum was not issued through notice-and-comment rulemaking procedures, and the EPA was careful to caveat its utility and ultimate reliability for that reason.

The EPA disagrees with claims that the EPA is applying the August 2018 memorandum inconsistently based on the EPA's actions with regard to Arizona, Iowa, and Oregon. The EPA withdrew a previously proposed approval of Iowa's SIP submission that was premised on a 1 ppb contribution threshold, and re-proposed and finalized approval of that SIP based on a different rationale using a 1 percent of the NAAQS contribution threshold. 87 FR 9477 (Feb. 22, 2022); 87 FR 22463 (April 15, 2022). The EPA also disagrees with any claim that Oregon and Arizona were ''allowed'' to use a 1 ppb or higher threshold. The EPA approved Oregon's SIP submission for the 2015 ozone NAAQS on May 17, 2019, and both Oregon and the EPA relied on a 1 percent of the NAAQS contribution threshold. 84 FR 7854, 7856 (March 5, 2019) (proposal); 84 FR 22376 (May 17, 2019) (final). In the proposal for this action, the EPA explained it was not proposing to conduct an error correction for Oregon even though updated modeling indicated Oregon contributed above 1 percent of the NAAQS to monitors in California.

The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information). In 2016, the EPA approved Arizona's SIP for the earlier 2008 ozone NAAQS based on a similar rationale with regard to certain monitors in California. 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule). We are deferring finalizing a finding at this time that such a rationale is appropriate

[183] EPA notes that Congress has placed on 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.

[184] *See* 86 FR 23054, 23058 (April 30, 2021).

with respect to the more protective 2015 ozone NAAQS. While Arizona and Oregon's interstate transport obligations for the 2015 ozone NAAQS remain pending (along with several other states), there is no inconsistency in the treatment of these states or any other state at Step 2.

Some commenters claim the EPA must use a 1 ppb threshold based on the identification of 1 ppb as a significance threshold in one step of the PSD permitting process. The EPA's SIL guidances, however, relate to a different provision of the Clean Air Act regarding implementation of the prevention of significant deterioration (PSD) permitting program. This program applies in areas that have been designated attainment of the NAAQS and is intended to ensure that such areas remain in attainment even if emissions were to increase as a result of new sources or major modifications to existing sources located in those areas. This purpose is different than the purpose of the good neighbor provision, which is to assist downwind areas (in some cases hundreds or thousands of miles away) in resolving ongoing nonattainment of the NAAQS or difficulty maintaining the NAAQS through eliminating the emissions from other states that are significantly contributing to those problems. In addition, as discussed in preceding paragraphs, the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport. The threshold used in the context of PSD SIL serves a different purpose, and so it does not follow that they should be made equivalent. Further, commenters incorrectly associate the EPA's Step 2 contribution threshold with the identification of "significant" emissions (which does not occur until Step 3), and so it is not the case that the EPA is interpreting the same term differently.

The EPA has previously explained this distinction between the good neighbor framework and PSD SILs. *See* 70 FR 25162, 25190–25191 (May 12, 2005); 76 FR 48208, 48237 (Aug. 8, 2011). Importantly, the implication of the PSD SIL threshold is not that single-source contribution below this level indicates the absence of a contribution or that no emissions control requirements are warranted. Rather, the PSD SIL threshold addresses whether further, more comprehensive, multi-source review or analysis of air quality impacts are required of the source to support a demonstration that it meets the criteria for a permit. A source with estimated impacts below the PSD SIL may use this to demonstrate that it will not cause or contribute (as those terms are used within the PSD program) to a violation of an ambient air quality standard, but is still subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality.

Moreover, other aspects of the technical methodology in the SILs guidance compared to the good neighbor framework make a direct comparison between these two values misleading. For instance, in PSD permit modeling using a single year of meteorology the maximum single-day 8-hour contribution is evaluated with respect to the SIL. The purpose of the contribution threshold at Step 2 of the 4-step good neighbor framework is to determine whether the average contribution from a collection of sources in a state is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective. Using a 1 percent of the NAAQS threshold is more appropriate for evaluating multi-day average contributions from upwind states than a 1 ppb threshold applied for a single day, since that lower value of 1 percent of the NAAQS will capture variations in contribution. If EPA were to use a single day reflecting the maximum amount of contribution from an upwind state to determine whether a linkage exists at Step 2, commenters' arguments for use of the PSD SIL might have more force. This would in effect be a return to the pre-CSAPR contribution calculation methodology of using a single day, *see* 76 FR 48238. However, that would likely cause more states to become linked, not less. And in any case, consistent with the method in our modeling guidance for projecting future attainment/nonattainment and as the EPA concluded in 2011 in CSAPR, the present good neighbor methodology of using multiple days provides a more robust approach to establishing that a linkage exists at the state level than relying on a single day of data.

A commenter also claimed the 1 percent of NAAQS threshold is inconsistent with the standards of precision for Federal reference monitors for ozone and the rounding requirements found in 40 CFR part 50, appendix U, Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone. Commenter claimed that the 1 percent contribution threshold of 0.7 ppb is lower than the manufacturer's reported precision of these reference monitors and that the requirements found in Appendix U truncates monitor values of 0.7 ppb to 0 ppb. However, the commenter is mistaken in applying criteria related to the precision of monitoring technology to the modeling methodology by which we project contributions when quantifying and evaluating interstate transport at Step 2. Indeed, contributions by source or state cannot be derived from the total ambient concentration of ozone at a monitor at all but must be apportioned through modeling. Under our longstanding methodology for doing so, the contribution values identified from upwind states are based on a robust assessment of the average impact of each upwind state's ozone-precursor emissions over a range of scenarios, as explained in the 2016v3 modeling's Air Quality Modeling Final Rule TSD, in the docket for this rule, Docket ID No. EPA–HQ–OAR–2021–0668. This analysis is in no way connected with or dependent on monitoring instruments' precision of measurement. *See EME Homer City,* 795 F.3d 118, 135–36 ("[A] model is meant to simplify reality in order to make it tractable.' ") (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994).

To the extent that commenters argue that the EPA consider a less stringent threshold as a result of modeling uncertainty, the EPA disagrees with this notion. The EPA has successfully applied a 1 percent of NAAQS threshold to identify linked upwind states using modeling in three prior FIP rulemakings and numerous state-specific actions on good neighbor obligations. This continues to be a reasonable approach, and indeed courts have repeatedly declined to establish bright line criteria for model performance. In upholding the EPA's approach to evaluating interstate transport in CSAPR, the D.C. Circuit held that it would not "invalidate EPA's predictions solely because there might be discrepancies between those predictions and the real world. That possibility is inherent in the enterprise of prediction." *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 135 (2015). "[T]he fact that a 'model does not fit every application perfectly is no criticism; a model is meant to simplify reality in order to make it tractable.' " *Id.* at 135–36 (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994). *See also Sierra Club* v. *EPA,* 939 F.3d 649, 686–87 (5th Cir. 2019) (upholding EPA's modeling in the face of complaints regarding an alleged ''margin of error,'' noting challengers face a ''considerable burden'' in overcoming a ''presumption of regularity'' afforded ''the EPA's choice of analytical methodology'') (citing *BCCA Appeal Grp.* v. *EPA,* 355 F.3d 817, 832 (5th Cir. 2003)).

The Agency will continue to use the CAMx model to evaluate contributions from upwind states to downwind areas. The agency has used CAMx routinely in previous notice and comment transport rulemakings to evaluate contributions relative to the 1 percent threshold for both ozone and $PM_{2.5}$. In fact, in the original CSAPR, the EPA found that ''[t]here was wide support from commenters for the use of CAMx as an appropriate, state-of-the science air quality tool for use in the [Cross-State Air Pollution] Rule. There were no comments that suggested that the EPA should use an alternative model for quantifying interstate transport.'' 76 FR 48229 (August 8, 2011). In this action, the EPA has taken a number of steps based on comments and new information to ensure to the greatest extent the accuracy and reliability of its modeling projections at Step 1 and 2, as discussed elsewhere in this section.

The EPA disagrees with commenters that case law reviewing changes in agency positions such as *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502, 515 (2009), is applicable with respect to this issue. As explained above, under the terms of the August 2018 memorandum, the Agency did not conclude that the use of an alternative contribution threshold was justified for any states. But even if it were found that the Agency's position had changed between this rulemaking action and the August 2018 memorandum, the *FCC* v. *Fox* factors are met. We have explained above that there are good reasons for continuing to use a 1 percent of NAAQS threshold. We also are aware that we are not using a 1 ppb threshold despite acknowledging the potential for doing so in the August 2018 memorandum. We do not believe that any party has a serious reliance interest that would be sufficient to overcome the countervailing public interest that is served through the EPA's determination to maintain continuity with its longstanding, more protective 1 percent of NAAQS threshold in this action. *Cf.* 88 FR 9373 (reviewing reliance in the context of the SIP-disapproval action).

The EPA therefore will continue its longstanding practice of applying the 1 percent of NAAQS threshold in this action.

a. States That Contribute Below the Screening Threshold

Based on the EPA's modeling and considering measured data at violating monitors, the contributions from each of the following states to nonattainment or maintenance-only receptors in the 2023 analytic year are below the 1 percent of the NAAQS threshold: Colorado, Connecticut, the District of Columbia, Delaware, Florida, Georgia, Idaho, Maine, Massachusetts, Montana, Nebraska, New Hampshire, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Vermont, and Washington.[185] The EPA has already approved these states' 2015 ozone good neighbor SIP submittals. 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 final rule. Additionally, the EPA has made final determinations that two states outside the modeling domain for the air quality modeling analyzed in this final rulemaking—Hawaii[186] and Alaska[187]—do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state.

With respect to Wyoming, our methodology when applied using the 2016v3 modeling suggests that whether the state is linked is uncertain and warrants further analysis. The EPA intends to expeditiously review its assessment with respect to Wyoming and take action addressing Wyoming's good neighbor obligations for the 2015 ozone NAAQS through a separate action.

b. States That Contribute at or Above the Screening Threshold

Based on the maximum downwind contributions in Table IV.F–1, the Step 2 analysis identifies that the following 21 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, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. Based on the maximum downwind contributions in Table IV.F–1, the following 23 states contribute at or above the 0.70 ppb threshold to downwind modeling-based maintenance-only receptors in 2023: Arizona, Arkansas, California, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, West Virginia, and Wisconsin. Based on the maximum downwind contribution in Table IV.F–3, the following additional states contribute at or above the 0.70 ppb threshold to downwind violating monitor maintenance-only receptors in 2023: Kansas and Tennessee. (However, the EPA is not taking final action based on this analytical result for these two states at this time.) The levels of contribution between each of these linked upwind states and downwind nonattainment receptors and maintenance-only receptors are provided in the Air Quality Modeling Final Rule TSD.

Among the linked states are several western states—California, Nevada, and Utah. 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 western state's good neighbor SIP submittal that might otherwise be found to contribute above 1 percent of the NAAQS without concluding that additional emissions reductions are required at Step 3 of the framework.[188] 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.[189] The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

As explained in the following section, the EPA is not, in this action, altering its prior approval of Oregon's good neighbor SIP submission for the 2015 ozone NAAQS. For the remaining western states included in this rule, the EPA's modeling supports a conclusion that these states are linked above the

[185] The status of monitoring sites in California to which Oregon may be linked is under review. *See* section IV.G.

[186] The EPA approved Hawaii's 2015 ozone transport SIP on December 27, 2021. *See* 86 FR 73129.

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

[188] *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.

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

contribution threshold to identified ozone transport receptors in downwind 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-only 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 maintenance under Step 3. The EPA finds that for purposes of this final rule, the following 23 states are linked at Step 2 in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. In addition, the EPA finds that the following 20 States are linked at Step 2 in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. We note that our updated modeling for this final rule shows that two states, Minnesota and Wisconsin, that we found linked in 2026 at proposal are no longer projected to be linked in that year but are linked in 2023.[190] As at proposal, Alabama is only projected to be linked in 2023, not 2026.

For six states, the EPA's analysis at this time indicates that a linkage may exist in 2023 for which the EPA had not proposed FIP requirements, or the updated analysis for this final rule suggests that linkages we had previously found in the proposed action are now uncertain and warrant further analysis. The EPA intends to expeditiously address these states in a separate action or actions: Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming.

G. Treatment of Certain Monitoring Sites 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 the EPA's updated modeling used at proposal (2016v2) and again in the final modeling (2016v3), Oregon is modeled to contribute above the 1 percent of NAAQS threshold to several monitoring sites in California that would generally meet the EPA's definition of nonattainment or maintenance ''receptors'' at Step 1.[191] At proposal, the EPA explained that our analysis of the nature of the air quality problem at these monitoring sites led us 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). We explained that we reached this conclusion at Step 1 of our 4-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.[192] 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.'' [193] 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.'' [194] 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.[195]

Comment: Commenters criticized what they considered to be unfair treatment of Oregon, stating that the EPA is applying a higher contribution threshold than it applies to other states. Commenters argued that EPA has not established a specific threshold for why the level of upwind-state impact at these sites should not be considered meaningful. Commenters argued that our analysis ignored the fact that there are many monitoring sites in California to which Oregon contributes above 1 percent of the NAAQS. Commenters state that EPA has failed to explain why Oregon is not subject to this rulemaking, while other states contribute lower total downwind ozone contributions and fewer receptors. Commenters concluded that since Oregon is linked it should be subject to the same emissions control determinations at Step 3 and 4 as every other state, or otherwise apply the same ''nature of the air quality problem'' consideration to eliminate other receptors.

Response: The EPA acknowledges that several commenters opposed the proposed treatment of Oregon and the California monitoring sites to which it is linked in the proposed and final modeling. We also recognize that other commenters expressed confusion regarding the role of this proposed determination at Step 1 and how it relates to the longstanding 4-step interstate transport framework that the EPA is otherwise applying in this action. In recognition of these concerns and the need to give further thought to the appropriate treatment of both upwind states and downwind receptors in these circumstances, the EPA is deferring finalizing a finding at this time for Oregon. The current approval of the state's SIP submission will remain in place for the time being, pending further review. We make no final determination in this action regarding whether the California monitoring sites at issue should or should not be treated as receptors for purposes of addressing interstate transport for the 2015 ozone NAAQS.

V. 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 the 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 final rule and focuses on the 23 states with FIP requirements identified in the

[190] Minnesota and Wisconsin were linked to maintenance-only receptors in Cook County, IL in 2023. Minnesota and Wisconsin are not linked in 2026 because the 2026 average and maximum design values at the monitoring sites are projected to show attainment.

[191] Monitors are included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency is not making a determination in this action that these monitors are ozone transport receptors.

[192] 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

[193] 81 FR 15203.

[194] *Id.*

[195] *Id.*

previous sections. Following the existing framework as applied in the prior CSAPR rulemakings, the 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 [196]—to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test, which is central to EPA's Step 3 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 III.A.2 of this document, commenters on the proposed rule and previous ozone transport rules have suggested that the EPA should regulate VOCs as an ozone precursor. For this final 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 for nearly all of the linkages (121 out of 124 total). Across all receptors, the contribution from NO_X emissions ranges from 84 percent to 97 percent of the total anthropogenic contribution from upwind states. 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 final rule under are primarily NO_X-limited, rather than VOC-limited. Therefore, the EPA continues to find that regulation of VOCs as an ozone precursor in upwind states is not necessary to eliminate significant contribution or interference with maintenance in downwind areas in this final 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 V.B of this document describes the available NO_X emissions controls that the EPA evaluated for this final rule and their representative cost levels (in 2016$). Section V.C of this document discusses EPA's application of that information to assess emissions reduction potential of the identified control stringencies. Finally, section V.D of this document 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 whether, based on particularized evidence, its selected control strategy would result in over-control for any upwind state 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 V.D of this document.

Finally, while the EPA has evaluated potential emissions reductions from non-EGU sources in prior rules and found certain non-EGU emissions reductions should inform the budgets established in the NO_X SIP Call, this is the first action for which the EPA is finalizing non-EGU emissions reductions within the context of the specific, 4-step interstate transport framework established in CSAPR. 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 eliminate ''significant contribution'' while avoiding over-control.

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 inclusive of commenter-provided data. This analysis leads the EPA to conclude 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 determines, 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

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

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 rulemaking 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 V.B.2 of this document describes EPA's process for selecting specific non-EGU industries and emissions unit types included in this final rulemaking.

The EPA notes that its Step 3 analysis for this FIP does not assess additional 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 these emissions at the Federal level. EPA's various Federal mobile source programs, summarized in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules 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 through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *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 final rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this rule.[197] For further discussion of EPA's existing and ongoing mobile source measures, *see* section V.B.4 of this document.

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; and (5) installing new SCRs. Finally, for each of these combustion and post combustion technologies identified, EPA evaluated whether emissions reduction potential from generation shifting at that representative dollar per ton level was appropriate at this Step. Shifting generation to lower NO_X emitting or zero-emitting EGUs may occur in response to economic factors. 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. For the reasons explained in the following sections and supported by technical information provided in the EGU NO_X Mitigation Strategies Final Rule TSD included in the docket for this final rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only EGU NO_X emissions controls 1 and 3 are possible for the 2023 ozone season (fully operating existing SCRs and SNCRs). 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; those controls are assumed to be available by the beginning of the 2024 ozone season. All cost values discussed in the rest of the section 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.[198] The EPA determined in the Revised CSAPR Update that optimizing SCRs was a readily available approach for EGUs to reduce NO_X emissions in the 12 states addressed by a FIP in that rulemaking. Noticeable improvements in emissions rates at units with SCRs during the 2021 and 2022 compliance period further affirm the ability of sources to quickly implement this mitigation strategy and to realize emissions reductions from doing so. This emissions reduction measure is currently available at EGUs across the broader geography affected in this final rulemaking (including in states not previously affected by the Revised CSAPR Update). The EPA thus determines 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 Final Rule TSD for this rule describes a range of cost estimates for

[197] 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 specific requirements that apply in certain ozone nonattainment areas including 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 well as others that meet CAA requirements can be effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.

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

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. This cost distinction is reflected in the EPA's RIA cost estimates. When representing the cost of optimization here, the EPA uses the higher value to reflect both optimization of partially operating and idled controls. 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 in preparation for this rule, and subsequently evaluated for the final rule in 2022 and determined to still be appropriate. The description and development of the equations are documented in EGU NO_X Mitigation Strategies Final Rule TSD and accompanying documents.[199] They are also 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 action.

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. Considering the emissions data over the full time period from 2009–2019 results in a third-best rate of 0.079 pounds NO_X per million British thermal units (lb/mmBtu). 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 finalizes 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 lb/mmBtu or lower 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 end of the ozone season control period on September 30. 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.[200] Therefore, the EPA believes that optimization of existing SCRs is possible for the portion of the 2023 ozone season covered under this final rule. The recent successful implementation of this strategy for the Revised CSAPR Update Rule, and corresponding fast improvement in SCR performance rates at units with optimization potential, provides further supporting evidence of the viability of this timeframe.

The vast majority of SCR-controlled units (nationwide and in the 23 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 and 2022 emissions rates. Notably, the higher ozone season NO_X allowance price observed in 2022 resulted in more units operating their controls closer to their potential and bringing collective emissions from those 12 states closer to the 2023 emissions budgets for those states in this final rule, accordingly.

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

[200] 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 lb/mmBtu and 2005 average non-ozone season NO_X emissions rates that exceeded 0.12 lb/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

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 Final Rule TSD). For instance, in June of 2021—within months of the Revised CSAPR Rule being finalized—Miami Fort Unit 7 and Unit 8 (which had substantial SCR optimization potential) were able to reach levels of 0.07 lb/mmBtu of NO_X (a greater than 50 percent reduction from where they had operated the prior year during the same month). Such empirical data further illustrates the viability of this mitigation strategy for the 2023 control period in response to this rule.

Comment: EPA received comments supporting the 0.08 lb/mmBtu emissions rate as achievable and, according to some commenters, underestimate the control's potential. Some of these commenters went on to provide their own analysis demonstrating that the 0.08 lb/mmBtu was achievable not only on average for the non-optimized fleet, but also for these individual units and that the resulting state emissions budgets were likewise achievable. Some commenters suggested that the rate should be lower and premised on EPA using the first- or second-best year instead of the third best year of SCR performance. Some commenters observed that using the same methodology, but omitting SCR units that have since retired, could deliver an even lower SCR performance benchmark rate.

Response: The EPA notes that updating the inventory of coal-fired EGUs to reflect recent retirements and to include data reported since 2019 (*e.g.,* 2009–2021) would provide a lower value of 0.071 lb/mmBtu. However, EPA acknowledges that 2020 operational data included impacts from COVID–19 pandemic shutdowns (such as atypical electricity demand patterns) which complicate interpretations of typical EGU emissions performance. Additionally, EPA believes that in this context, a unit's retirement in 2020 or 2021 does not obviate the usefulness of its prior SCR operational data for assessing the emissions control performance of other existing SCRs across the fleet. Consequently, EPA is continuing to use the same value of the 0.08 lb/mmBtu emissions rate calculated from the 2009–2019 data set identified at the time of the final Revised CSAPR Update Rule in this rulemaking. EPA's analysis focuses on the third best ozone season average rate because EPA believes that the first- or second-best rate, consistent with its CSAPR Update final rule and in the Revised CSAPR Update, could give undue weight to the emissions control performance of new SCRs in their first year of service and their corresponding newer SCR components. It does not necessarily reflect achievable ongoing NO_X emissions rates at relatively older SCRs. The third-lowest season was selected because it represents a time when the unit was most likely consistently and efficiently operating its SCR in a manner representative of sustained future operation.

Comment: Other commenters suggested that EPA should apply a higher NO_X emissions rate than 0.08 lb/mmBtu to existing SCR at coal EGUs premised on considerations such as: a generally reduced average capacity factor for coal units in recent years, the age of the boiler, coal rank (bituminous or subbituminous), or other unit-specific considerations that commenters claim make the 0.08 lb/mmBtu rate unattainable for a specific unit.

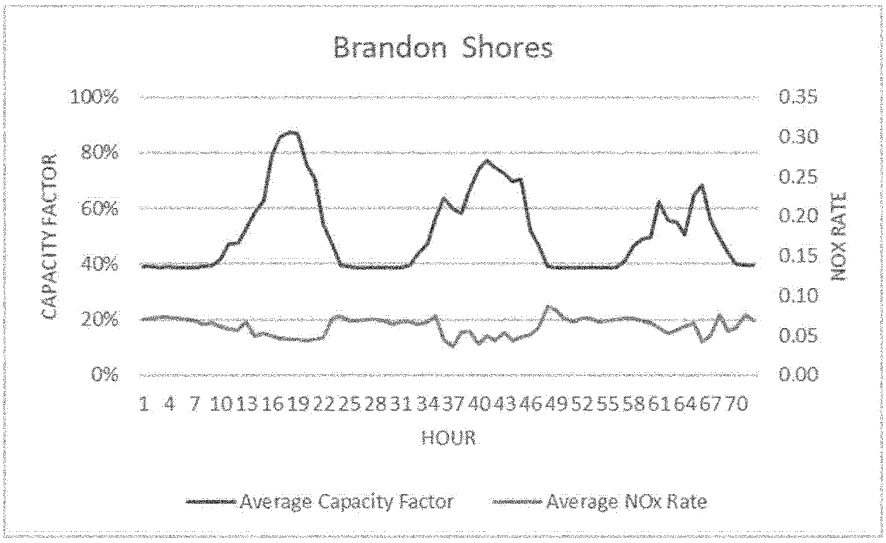
Response: EPA did not find sufficient justification to apply a higher average emissions rate than 0.08 lb/mmBtu. EPA found that some commenters were misunderstanding or misconstruing both EPA's assumption and implementation mechanism as a unit-level requirement for every SCR-controlled unit instead of a reflection of a fleet-wide average based on a third-best rate. The commenters' observation—that 0.08 lb/mmBtu may be difficult for some units to achieve or may not be a preferred compliance strategy for a given unit given its dispatch levels—does not contradict EPA's assumption, but rather supports its methodology and assumptions. As EPA pointed out in the proposed rule, this fleet-level emissions rate assumption of 0.08 lb/mmBtu for non-optimized units reflects, on average, what those units would achieve when optimized. Some of these units may achieve rates that are lower than 0.08 lb/mmBtu, and some units may operate above that rate based on unit-specific configuration and dispatch patterns. In other words, EPA is using this assumption as the average performance of a unit that optimizes its SCR, recognizing that heterogeneity within the fleet will likely lead some units to overperform and others to underperform this rate. Moreover, a review of unit-specific historical data indicates that this is a reasonable assumption: not only has the group of units with SCR optimization potential demonstrated they can perform at or better than the 0.08 lb/mmBtu rate on average, over 90 percent of the individual units in this group have already met this rate on a seasonal and/or monthly basis based on their reported historical data.

Additionally, EPA's examination of units experiencing SCR performance deterioration included notable instances of poor NO_X control at *increased* capacity factors. As an example, Miami Fort Unit 7 had considerably more hours of operation at a 70 to 79 percent capacity factor in 2019 compared to previous years. However, Miami Fort Unit 7's ozone-season NO_X emissions rate *substantially increased* in 2019 compared to previous years. This SCR performance deterioration runs counter to the notion that an increase in emissions rates is purely driven by reduced capacity factor, as suggested by commenters. This substantial deterioration in the median emissions rate performance is observable even when comparing specific hours in 2019 to specific hours in prior years when the unit operated in the same 70 to 79 percent capacity factor range. In fact, in 2019 the unit experienced notable emissions rate increases from prior years across multiple capacity factor ranges as low as 40 percent to as high as 80 percent. This type of data indicates instances where the increase in emissions rate (and emissions) is not necessitated by load changes but is more likely due to the erosion of the existing incentive to optimize controls (*i.e.,* the ozone-season NO_X allowance price has fallen so low that unit operators find it more economic to surrender additional allowances instead of continuing to operate pollution controls at an optimized level).

EPA observed this pattern in other units identified in this rulemaking as having significant SCR optimization emissions reduction potential. In the accompanying Emissions Data TSD for the supplemental notice that EPA recently released in a proceeding to address a recommendation submitted to EPA by the Ozone Transport Commission under CAA section 184(c), EPA noted, ''In their years with the lowest average ozone season NO_X emissions rates in this analysis, these EGUs had relatively low NO_X emissions rates at mid- and high-operating levels; moreover, there was little variability in NO_X emissions rates at these operating levels. However, during the 2019 ozone season, these EGUs had higher NO_X emissions rates and greater variability in NO_X emissions rates across operating levels than in the past, particularly at mid-operating levels.'' [201] That hourly data analysis, included in this docket, controls for operating level changes and still finds there to be instances across multiple SCR-controlled units where hourly emissions rates are increasing even when compared to the same load levels in previous years.

Some commenters have alleged that in recent years coal-fired EGUs have declined in capacity factor and that SCR performance declines at those lower operating levels. However, hourly data indicate that maintaining consistent SCR performance at lower capacity factors is possible. For example, the unit-level performance data in Figure 2 to section VI.B of this document show the emissions rate at a coal-fired EGU with existing SCR staying relatively low (consistent with our optimization assumption of 0.08 lb/mmBtu) and stable across a wide range of capacity factors.[202]

Figure 2 to section V.B.1.a: Example of Consistently Low Unit-level Emissions Rate During Periods of Varying Capacity Factor



Furthermore, most recent data from 2022 illustrates that cycling units do have the ability to adjust cycling patterns in a manner that enables them to maintain a lower emissions rate throughout the season while still achieving a load cycling pattern at the unit. For example, the SCR-controlled Conemaugh Unit 2 in Pennsylvania adjusted operating patterns in 2022 to have a slightly higher minimum load in most hours (maintaining a range of 550 MW–900 MW for most hours as opposed to 450 MW–900 MW observed in 2021). This change in minimum load, and corresponding minimum operating temperature, enabled the unit to maintain emissions rates in the 0.05 lb/mmBtu to 0.10 lb/mmBtu range for most of the 2022 season (as opposed to NO_X emissions rates that regularly exceeded 0.25 lb/mmBtu in the 2021 season). This 2022 improvement in SCR operation occurred during a period when allowance prices increased relative to prior years, creating an incentive for potential emissions reductions through SCR optimization.

Comment: EPA also received comment suggesting it should deviate from its approach in the CSAPR Update of using a nationwide data set of all SCR controlled coal units to establish a third best year, and instead limit the dataset to either just the covered states, or—in the case of some commenters—just to the baseline years of those units at which EPA is identifying optimization potential. They claim the current methodology may capture extremely efficient SCR performance years at the best performing units and that level of performance may not be available at all units with optimization potential. These commenters also disagree with the EPA finding that SCRs can consistently maintain a 0.08 lb/mmBtu rate over time.

Response: EPA reviewed the data and its methodology and evaluated it against its intention to identify a technology-specific representative emissions rate for SCR optimization. In doing so, EPA did not identify any need to make the suggested change. EPA is interested in the performance potential of a technology, and a larger dataset provides a superior indication of that potential as opposed to a smaller, state-limited dataset. Moreover, EPA's use of the third best year (as opposed to best) from its baseline period results in an average optimization level that is robust

[201] ''Analysis of Ozone Season NO_X Emissions Data for Coal-Fired EGUs in Four Mid-Atlantic States,'' EPA Clean Air Markets Division. December 2020. Available at *https://www.epa.gov/sites/production/files/2020-12/documents/184c_emission_data_tsd.pdf.*

[202] EPA, *Air Markets Program Data.* Available at *www.epa.gov/ampd.*

to the commenters' concern that EPA should not overstate the fleetwide representative optimization level. Prior experience with EPA's methodology and program has borne out empirical evidence of its reasonableness. In both the CSAPR Update and in Revised CSAPR Update rule, EPA appropriately relied on the largest dataset possible (*i.e.,* nationwide) to derive technology performance averages that it then applied respectively to the CSAPR Update 22-state region and the Revised CSAPR Update's 12-state region. EPA repeats that successful approach in this rule. Finally, as noted in the preceding paragraphs, in affirming the reasonableness of this approach, EPA examined the historical reported data (pre-2021) for the units in the states with SCR optimization potential and found the nationwide derived average appropriate and consistent with demonstrated capability and performance of units within those states. That is, the vast majority of units to which this resulting emissions rate assumption was being applied had demonstrated the ability to achieve this rate in some prior year for an extended monthly or seasonal basis. This information is discussed further in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket.

Comment: Some commenters suggested the price of SCR optimization is higher than the $1,600 per ton figure proposed due to current market conditions for aqueous ammonia or other input prices.

Response: EPA provides a representative cost for this mitigation technology which is anticipated to reflect the cost, on average, throughout the compliance period for the rule. While there may be volatility in the market during that period where the price falls above or below the single representative threshold value, EPA's EGU NO_X Mitigation Strategies Final Rule TSD explains how the representative cost is derived and is inclusive of consultation and vetting by third party air pollution control consulting groups. Commenters did not demonstrate that observed 2021 elevated prices amid market volatility would continue into the future compliance periods discussed in this rule. Moreover, the selection of the mitigation technology is reflective of a variety of factors including reduction potential and air quality impact. A higher cost (commenter suggests up to $3,800 per ton) would not change EPA's determination that optimizing already existing SCRs is an appropriate mitigation strategy for Step 3 emissions reduction analysis in this rulemaking as it would remain one of the most widely available, widely practiced, and lowest cost mitigation measures with meaningful downwind air quality benefit. Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD further addresses commenters' concerns as it provides a variety of sensitivities showing cost per ton levels under a variety of different input assumptions (including higher material and reagent cost). It supports the continued inclusion of this technology in the rule even in the event that higher reagent costs extend into compliance years.

Comment: While many commenters supported the feasibility of 2023 ozone-season implementation by noting the ''immediate availability'' of SCR optimization, other commenters argued that the engineering, procurement, and other steps required for SCR optimization were not feasible given the anticipated limited window between rule finalization and the start of the 2023 ozone season.

Response: There is ample evidence of units restoring their optimal performance within a two-month timeframe. Not only do units reactivate SCR performance level at the start of an ozone-season when tighter emissions limits begin, but unit-level data also shows instances where sources have demonstrated the ability to quickly alter their emissions rate within an ozone-season and even within the same day in some cases. Moreover, this emissions control is familiar to sources and was analyzed and included in the Revised CSAPR Update emissions budgets finalized in 2021 and the CSAPR Update emissions budgets finalized in 2016. With this experience, and notice through the March 2022 proposed rule, as well as over two months from final rule to effective date, the viability of this emissions control for the 2023 ozone season is consistent with the 2-week to 2-month timeframe that EPA identified as reasonable in the CSAPR Update, Revised CSAPR Update, and in this rulemaking. Similar to prior rules, commenters provide some unit-level examples where it has taken longer. Also similar to those prior rules, EPA does not find those unit-level examples compelling in the context of its fleet average assumptions and in the implementation context of a trading program which provides compliance alternatives in the event a specific unit prefers more time to implement a given control measure. As noted in *Wisconsin,* ''. . . all those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'' 938 F.3d at 330.

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-art combustion control technology. For this rulemaking, the Agency re-evaluated its NO_X emissions rate assumptions 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 lb/mmBtu can be achieved on average depending on the unit's boiler configuration,[203] and, once installed, reduce NO_X emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update. They are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD. In particular, the EPA is finalizing, as proposed, the application of the 0.199 lb/mmBtu emissions rate assumption for both boiler types (tangentially and wall fired). EPA's analysis calculated average emissions rates of 0.199 lb/mmBtu for combustion controls on dry bottom wall fired units and 0.146 lb/mmBtu for tangentially fired units. However, 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 assignment of a 0.199 lb/mmBtu emissions rate for combustion controls at all affected unit types is robust to current and future coal choice at a unit.

The EPA has previously examined the feasibility of installing combustion controls and found that industry had demonstrated ability to install state-of-

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

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).[204] 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.[205] Those comments provided information on the equipment and typical installation time frame for new combustion controls, accounting for all steps. To date, EPA has found 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 referenced timeframe of approximately 6 to 8 months to complete combustion control installation in the region, the EPA is finalizing 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 Final 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. 99 percent of units have some form of combustion controls, indicating the widespread cost-effectiveness of this control. *See* the *EGU NO_X Mitigation Strategies Final Rule TSD* for additional details.

At proposal EPA assumed that emissions reductions from combustion control upgrades at affected EGUs in states subject to the Revised CSAPR Update program could occur by 2023 given that those EGUs may have already begun pursuing such upgrades in response to that previous rule. However, EPA does not have data to confirm that presumption, and hence EPA is determining in this final rule that combustion control upgrades for all affected EGUs, regardless of whether they were previously subject to the Revised CSAPR Update program, should be considered available by the 2024 ozone season, consistent with the deployment schedule noted in this section.

Comment: Some commenters suggested that EPA, in its modeling for the proposed rule, overestimated the ability of combustion control technologies to achieve very low NO_X emissions rates. The commenters claim EPA's assumptions are derived from projected NO_X emissions rates based on ideal circumstances for NO_X emissions reductions, including combinations of fuel composition and unit design that are not typical and should not be extrapolated to the national inventory.

Response: EPA's emissions performance rate for state-of-the-art combustion controls is derived from historical data and takes both boiler type and coal choice into account. EPA reviewed historical data and identified the average emissions rates for units with this technology already in place. It segmented this analysis by boiler type (dry-bottom wall-fired boiler and tangentially-fired, and further segmented by coal rank to assess the average performance among these varying parameters. As explained in the *EGU NO_X Mitigation Strategies Final Rule TSD,* EPA chose an emissions rate for which it verified accommodated (*i.e.,* was greater than or equal to) the average performance rate identified above for each boiler configuration with state-of-the-art combustion controls and resulted in reductions consistent with the technology's assumed percent reduction potential when applied to this subset of units. It also assessed whether the rate had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls. EPA further assessed the percent reduction that achieving this rate would require from the specific segment of the fleet identified as having this mitigation measure available. Here too, EPA found that the effective percent reduction for the identified fleet (inclusive of their existing coal rank choice) is well within the historical performance range for this technology. Therefore, EPA is finalizing the combustion control upgrade performance assumption of 0.199 lb/mmBtu as appropriate representative average performance rate for this technology and robust to different boiler types and coal ranks.

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 22 linked states with EGU reductions identified in this final rule, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.[206] Recent power sector data suggest that, in some cases, SNCR controls have been operating less in 2021 relative to performance in prior years. For instance, EPA reviewed the last five years of performance data for all the units with SNCR optimization potential in its Engineering Analysis. It found that in 2021—the most recent year reviewed—that the weighted average ozone season emissions rate for these units was higher than the prior three years (indicating some deterioration in average performance). Moreover, a unit level review illustrated that 80 of the 107 units had performed better in a prior year by an average of 13 percent—indicating substantial optimization potential.[207]

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. In this final rule, the EPA is determining that this emissions

[204] 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.

[205] EPA–HQ–OAR–2015–0500–0093.

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

[207] See ''Historical Emission Rates for Units with SNCR Optimization Potential'' in the docket for this rulemaking.

control measure is available beginning in the 2023 ozone season.

Using the Retrofit Cost Analyzer described in the *EGU NO_X Mitigation Strategies Final 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 finalizes 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.

d. Installing New SNCRs

The EPA evaluated potential emissions reductions and associated costs from retrofitting EGUs with new SNCR post-combustion controls at steam units lacking such controls, which can achieve a 25 percent NO_X reduction on average. 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.[208] 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 Final Rule TSD,* the EPA estimated that $6,700 per ton reflects a representative SNCR retrofit cost level for these units.

For this rulemaking, EPA is not considering SNCR installation timing unto itself but is instead considering how long eligible EGUs may need to adopt either SNCR or SCR as a post-combustion control measure. 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. However, SNCR retrofits have less pollution reduction potential than SCRs, and as explained further in the next section, the EPA is identifying the retrofit of new SCR rather than SNCR as a strategy for larger steam units due to this lower removal efficiency. This approach respects empirical evidence that larger coal-fired EGUs which installed post-combustion NO_X control technology have overwhelmingly chosen SCRs over SNCRs. Even for smaller units less than 100 MW identified as potential candidates for SNCR technology, the EPA does not want to preclude those units from pursuing SCR in lieu of SNCR.

Therefore, in this final rule the EPA defines the availability of emissions reductions from post-combustion control installation to be in 2026, the same period as the start of SCR-based reductions becoming available, to allow enough time for eligible EGUs to choose between SCR or SNCR. SNCR installation shares similar implementation steps with and also need to account for the same regional factors as SCR installations, which are described in the next section. While the EPA is determining that at least 16 months would be needed to complete all necessary steps of SNCR development and installation, an eligible EGU choosing new SCR instead would require installation timing of 36 to 48 months. EPA believes its finalized joint timing considerations for post-combustion control retrofits (SNCR and SCR) are justified given that post-combustion control retrofit decisions are subject to unit-specific economic and engineering factors and are sensitive to operator compliance strategy choices with respect to multiple regulatory requirements.

Comment: Some commenters argued that post-combustion control timing assumptions (SCR and SNCR) should be decoupled, which could result in the EPA using the 16-month time frame specific to SNCR installation to require emissions reductions related to new SNCR installations by the 2025 ozone season.

Response: The EPA does not agree that decoupling SCR and SNCR timing consideration is justified in the context of this final rule's emissions control program for EGUs. Approximately 1,000 tons of emissions reduction potential are estimated for the small coal EGUs deemed eligible for SNCR retrofit. The incentives provided through the implementation of this rule's trading program will encourage these EGUs to determine and adopt emissions reduction measures (including SNCR or SCR) as soon as possible to reduce their allowance holding compliance burden. By scheduling SNCR-related emissions reductions potential for the 2026 ozone season, the EPA preserves the opportunity for considerably superior emissions reduction potential from these EGUs should they select SCR retrofit instead, while still requiring post-combustion control emissions reduction potential ahead of the next attainment date.

Comment: Some commenters argued that the upper range of SNCR NO_X removal performance (40 percent) referenced by EPA is optimistic for many boilers.

Response: EPA evaluated both actual performance and engineering literature regarding SNCR retrofit technology and found both sources supported the range of reduction estimates cited by EPA. (Refer to the *EGU NO_X Mitigation Strategies Final Rule TSD* in the docket for this rulemaking for additional information.) Moreover, for purposes of calculating state budgets, EPA assumes 25 percent reduction from this technology—not 40 percent—which reflects a value well within the range of documented performance for this technology. Remaining comments on SNCR performance potential are addressed in the *RTC* Document and in the *EGU NO_X Mitigation Strategies Final Rule TSD.*

e. Installing New SCRs

Selective Catalytic Reduction (SCR) controls already exist on over 66 percent of the coal fleet in the linked states that are subject to a FIP in this 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

[208] *See* EGU NO_X Mitigation Strategies Final Rule TSD for additional discussion.

rapidly due to a lack of economies of scale.[209]

The amount of time needed to retrofit an EGU with new SCR extends beyond the 2023 ozone season. Similar to the SNCR retrofits discussed in this section, 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. 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). However, since that time, the EPA has found up to 36–48 months to be a more appropriate installation timeframe for regionwide actions when the EPA is evaluating multiple installations at multiple locations.[210]

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.

While EPA finds that 36 months is a possible time frame for SCR installation at individual units or plants, the total of nearly 31 GW of coal capacity with SCR retrofit potential and 19 GW of oil/gas steam capacity with SCR retrofit potential within the geographic footprint of the final rule is a scale of retrofit activity that is not demonstrated to have been achieved within a three-year span based on data from the past two decades. 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, EPA is allowing in this final rule between 36 to 48 months, consistent with the regional time frame discussed for SCR retrofit in prior rules, for the full implementation of reductions commensurate with this volume of SCR retrofit capacity, as described further in section VI.A of this document.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO_X rates of 0.05 lb/mmBtu or less. These updates are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD.[211] 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.[212]

The 0.05 lb/mmBtu emissions 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 emissions rate data for coal-fired units that had a relatively recent SCR installation (within the last 10 years). The best performing 10 percent of these SCRs were demonstrating seasonal emissions 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.[213] 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 emissions 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 on a dollar per ton basis. Therefore, the EPA identified the portion of the oil/gas steam fleet meeting these criteria (*i.e.,* greater than or equal to 100 MW and emitting more than 150 tons per ozone season) as representative of the SCR retrofit reduction potential.[214] 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.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of SCR installation occurring in

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

[210] *See, e.g.,* CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018) and Revised CSAPR Update, 86 FR 23102 (April 30, 2021). *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.*

[211] 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.

[212] 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 Final Rule TSD for more discussion.

[213] See "IPM Model—Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers".

[214] 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.

a limited region of the country would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that achieving such a timeframe against a backdrop of such challenging circumstances is unprecedented and that EPA's assumptions ignore that many of the remaining unretrofitted coal units reflect more site-specific challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA reviewed the comments and is making several changes in this final rule to address some of the concerns identified by the commenters. In particular, EPA found that its own review of historical retrofit patterns as well as technical information submitted by commenters supported commenters' concerns regarding: (1) current and anticipated constraints in labor and supply markets, (2) the potential collective capacity levels of SCR retrofit within 36 months, and (3) possible site-specific complexities at the remaining units without an existing SCR. To address these concerns, EPA is phasing in its SCR installation requirement over a 48-month time frame in this final rule, instead of a 36-month time frame as proposed (see additional detail and discussion in section VI.A.2.a and the EGU NO_X Mitigation Strategies Final Rule TSD). EPA will require half of the reductions associated with SCR installation in 2026 and the other half in 2027. Additionally, EPA is moving the daily backstop rate for these units with identified SCR reduction potential from 2027 to no later than 2030, which defers the increased allowance surrender ratio for emissions above the backstop rate at any outlier units unable to complete the retrofit during that time frame. These adjustments continue to incentivize reductions in NO_X emissions by the attainment date that are consistent with cost-effective SCR controls, but provide more flexibility (both from timing and technology perspective) in how they are procured.

Some commenters requested more than 48 months to install SCR controls based on the collective total volume of SCR retrofit volume identified and past projects that took five or more years. EPA disagrees with these comments and finds that they ignored key aspects of the proposed rule. First, the final rule does not directly require implementation of SCR; rather, it requires reductions commensurate with SCR installations based on a rigorous assessment of SCR retrofit potential. Implementing the reductions through a trading program means that sources in many cases, as suggested by the *Regulatory Impact Analysis (RIA),* will find alternative, and more economic means, of reducing emissions—including reduced generation and retirements that are already planned based on the age of the unit, decarbonization goals, or compliance with other Federal/state/local regulation compliance dates. Moreover, the additional new generation incentives provided by the Inflation Reduction Act (enacted after the proposed rule) will further increase the pace of new generation replacing some of the older generating capacity identified as having retrofit potential.[215] In short, although EPA identified the total SCR retrofit capacity potential for today's existing fleet and does not premise any reduction requirements of incremental retirements, the announced and planned futures for these units indicates that many will likely retire instead of installing SCR. For the capacity identified at Step 3 which lacks SCR, the planned or projected retirement in place of a retrofit moots the SCR timing for these units. Moreover, it also reduces the demand for associated labor and materials which, in turn, frees up resources for any units proceeding with a SCR retrofit. Therefore, comments which cite labor and supply chain challenges for accommodating the entire fleet capacity identified as having SCR retrofit potential significantly overstate the supply-side challenge—as it ignores the fact that much of this capacity has explicit or expected operation plans that will result in compliance without a retrofit.

Even for sources choosing a SCR retrofit compliance pathway, many of these comments ignore the timing flexibilities of the trading program, which (particularly with the changes to the backstop daily emissions rate in this final rule) allow sources to temporarily comply through means other than SCR retrofit if they experience any site-specific retrofit limitations that increase their time frame. Also, historical examples of SCR retrofit projects that exceeded 48 months in duration do not necessarily demonstrate that such projects are impossible in less than 48 months, but rather that they can extend beyond the timeframe if no requirements or incentives are in place for a faster installation. Some also cite site-specific conditions that resulted an outlier cases of project timing that would not be representative of the conditions expected at future retrofit projects.[216]

Comment: Some stakeholders suggested that EPA's cost estimates of $11,000 per ton are premised on a 15-year book life of the equipment and are therefore too optimistic for units that plan to retire in well under 15 years.

Response: EPA analysis of SCR retrofit cost reflects a representative value for the technology based on a weighted average cost. The underlying data and the discussion in the EGU NO_X Mitigation Strategies Final TSD illustrates that these costs can vary significantly at the unit level based on factors such as the length of time a pollution control technology would be in operation, the capacity factor of the unit (*i.e.,* how much does it operate), its size or potential to emit, and its baseline emissions rate. The EPA has not in prior transport rulemakings used such factors as justification to excuse any source that is significantly contributing to nonattainment or interfering with maintenance in another state from eliminating that significant contribution as expeditiously as practicable. Unlike under other statutory provisions that may require retrofit of emissions controls on existing sources, such as under CAA section 111(d) or CAA section 169A, there is no remaining useful life factor expressly identified as a justification to relax the requirements of CAA section 110(a)(2)(D)(i)(I). EPA continues to believe that where an emissions control strategy has been identified at Step 3 that is cost-effective on a regional scale and provides meaningful downwind air quality improvement, and is thus appropriately identified as necessary to eliminate significant contribution under the good neighbor provision, it would not be appropriate to allow emissions to continue in excess of those achievable emissions reductions beyond the timeframe for expeditious implementation of reductions as provided under the larger title I structure of the Act for attaining and maintaining the NAAQS. The court in *Wisconsin* recognized that where such emissions have been identified, they should be eliminated as expeditiously as practicable, and in line with the

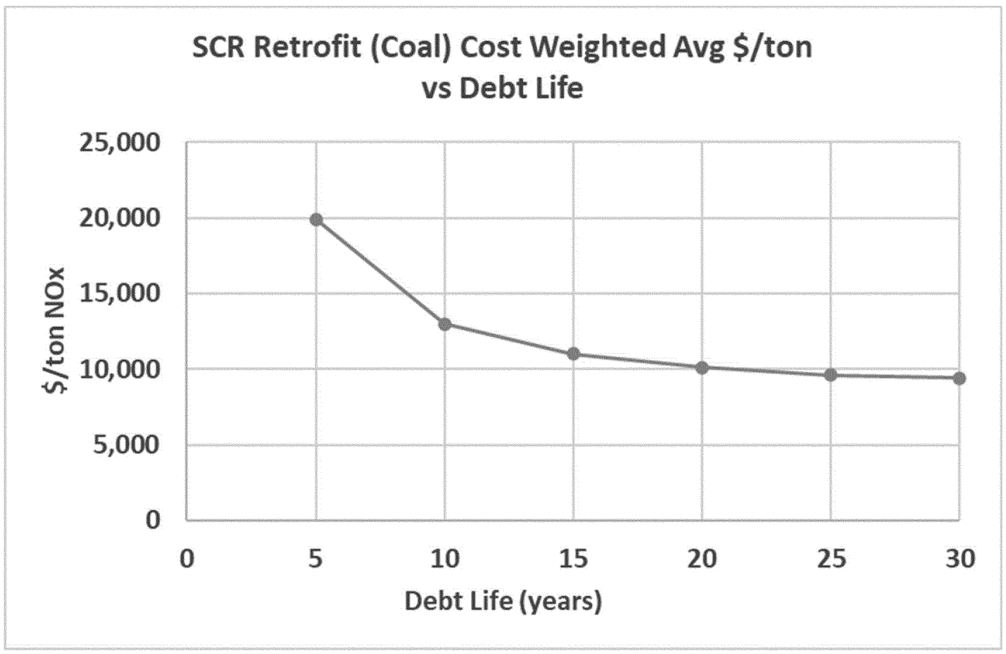
[215] *See* ''Regulatory Impact Analysis for 2015 Good Neighbor Plan, Appendix 4A: Inflation Reduction Act EGU Sensitivity Run Results.'' EPA estimated the compliance costs and emissions changes of the final rule in the presence of the IRA, but given time and resource constraints, did not quantify benefits for this sensitivity.

[216] Commenters, for example, cited the timing of SCR installation at Sammis 6 and 7. Here, the SCR design and material delivery schedule were tailored to meet unique site conditions that were unlike many other SCR systems where large modules can be used to maximize shop and ground assembly techniques. Additional information is available at *https://www.babcock.com/home/about/resources/success-stories/sammis-plant.*

attainment schedule for downwind areas, which, for the 2015 ozone NAAQS, is provided in CAA section 181. 938 F.3d at 313–20.

Further, EPA observes that more than one-third of the identified SCR retrofit potential (in terms of generating capacity) has no planned retirement date within 15 years, and therefore the cost of pollution control technology on such units would likely be lower, holding all other parameters equal, on a dollar per ton basis by virtue of the length of time the pollution control equipment may be in operation. Nor does EPA agree that units that would retire in less than 15 years should automatically be considered to face an unreasonably higher cost burden. Based on data analyzed in the EGU NO_X Mitigation Strategies Final Rule TSD, we find that the cost per ton associated with SCR retrofit technology does not begin to increase significantly above the $11,000/ton benchmark unless units have dramatically lower operating capacity or retire in less than 5 years' time—as illustrated in Figure 1 to section V.B.1.e of this document.

Figure 1 to section V.B.1.e: SCR Retrofit Cost Weighted Average $/ton vs Debt Life[217]



Finally, EPA's identification of this mitigation strategy is not meant to be limited only to units that experience a retrofit cost that is less than the representative cost threshold. First, that threshold represents an average, meaning that EPA's analysis already recognizes that some units on a facility-specific basis may face costs higher than that threshold. Further, EPA identifies this technology as widely available, implemented in practice already at many existing EGUs, and now standard for any coal-fired unit coming online in the past 25 years. More than 66 percent of the current large coal fleet already has such controls in place. Even if the cost were higher for some units for the reasons provided by commenters—and there were no less costly means provided to them to achieve the same level of emissions reduction (which the trading program allows for)—that would not necessarily obviate EPA's basis for finding that an emissions-reduction requirement commensurate with this standard pollution control practice for this unit type is warranted. The implementation of emissions reductions through a trading program, and its corresponding compliance flexibilities, make the use of a single representative cost all the more appropriate in this assessment. Therefore, upon reviewing all of the data including the information supplied by commenters, and even accounting for certain units' announced plans to retire earlier than an assumed 15-year book life for SCR retrofit technology, EPA finds its representative cost for this technology to be appropriate and reasonable for purposes of analysis under CAA section 110(a)(2)(D)(i)(I) and maintains this cost estimate in the final rule.

However, in recognition of the unique circumstances related to the transition of the power sector away from coal-fired and other high-NO_X emitting fuels and generating technologies, which is anticipated to accelerate in the late 2020s and into the 2030s, EPA has adjusted the final rule to avoid imposing a capital-intensive control technology retrofit obligation which could have overall net-negative environmental consequences (*e.g.,* by extending the life of a higher-emitting EGU or necessitating the allocation of material and personnel that could be used for more advanced clean-technology

[217] "Debt Life" refers to the term length, or duration, for a loan used to finance the retrofit.

innovations). For units that plan to retire by 2030, the final rule—by extending the daily backstop rate to 2030—allows these units to continue to operate, so long as they comply with the mass-based emissions trading program requirements.[218] Therefore, a unit experiencing a higher dollar per ton retrofit cost due to retirement plans has the flexibility to install less capital intensive controls such as SNCR, procure less costly allowances through either banking or purchase, or they may also reduce their allowance holding requirement through reduced utilization consistent with their phasing out towards a planned retirement date. This flexibility that EPA has included in the final rule is discussed in further detail in section VI.B of this document.

Comment: Some commenters suggested that the 0.05 lb/mmBtu emissions rate assumed for new SCRs at large coal units is not achievable at all coal units with retrofit potential and that EPA should raise this performance assumption to a value of 0.08 lb/mmBtu consistent with that assumption for existing SCRs.

Response: First, EPA believes the commenter misunderstands its intention with the 0.05 lb/mmBtu SCR rate assumption. This is meant to reflect a representative assumption for emissions rate performance for new SCR installed on the currently unretrofitted coal fleet—in this respect, it represents an average, not a maximum. EPA recognizes that some units will likely perform better (*i.e.,* lower) than this rate and some will potentially perform worse (*i.e.,* higher) than this rate—but that 0.05 lb/mmBtu is a reasonable representation of new SCR retrofit potential on a fleet-wide basis and for identifying expected state and regional emissions reduction potential from this technology. It would be inappropriate for EPA to use the worst performing tier of new SCR retrofit for this representative value. Moreover, EPA's review of historical environmental performance for recently installed SCRs does not support any indication that 0.05 is not representative of the retrofit potential for the fleet. EPA found that three quarters of the SCR retrofit projects completed in the last 15 years have achieved a rate of 0.05 lb/mmBtu or better on a monthly or seasonal basis. Moreover, its review of the engineering literature and consultation with third party pollution control engineering consultancies suggests that vendors are often willing to guarantee 0.05 lb/mmBtu seasonal performance for new SCR retrofit projects. Current SCR catalyst suppliers provide NO_X emissions warranties based at the catalyst's end-of-life period, often after 16,000 to 24,000 hours of operations, with newer catalyst achieving similar or better NO_X removal rates. Standard commercial terms, made by the purchaser to the SCR Retrofit supplier, can specify a system capable of meeting the proposed NO_X emissions rate and define the catalyst operational life before replacement. Thus, achieving the proposed reduction rates is accomplished through the buyer specifying the SCR retrofit requirements and the supplier providing an optimized system design and installing sufficient catalyst for the targeted end-of-life NO_X emissions rate. The agency is confident that SCR retrofit suppliers will be able to warrant their offerings for the emissions rates proposed in the regulation and to provide sufficient operating life for the affected sector.

Comment: Some commenters suggest that the evaluation of pollution control installation cost at Step 3 should be segmented depending on unit characteristics, and by failing to do so understate the cost of retrofitting SCR controls. In particular, these commenters note that units with lower capacity factors, different coal ranks, with pre-existing controls—such as SNCR—face substantially higher dollar per ton reduced costs than those that do not have such controls in place and should not be identified as a cost-effective mitigation strategy.

Response: Consistent with prior CSAPR rulemakings, at Step 3 EPA evaluates a mitigation technology and its representative cost and performance for the fleet on average. This representative cost is inclusive and robust to the portion of the fleet that may face higher dollar per ton cost. Both the ''Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Proposed Rule TSD'' (Feb. 2022), hereinafter referred to as the EGU NO_X Mitigation Strategies Proposed Rule TSD, and the EGU NO_X Mitigation Strategies Final TSD discuss the SCR retrofit cost specific to the segment of the fleet that has a SNCR in place and notes that those unit-level higher retrofit cost estimates are factored into its determination of the fleet-wide representative number. Although EPA believes its representative cost are appropriate and underpinned by operating assumptions reflective of the fleet averages, it nevertheless examined how cost would vary based on some of the variables highlighted by commenter. The EPA derived its capacity factor assumption based on expected future operations of this fleet segment that are inclusive of units operating at a range of capacity factors. It also examined how cost would change assuming different coal rank, assuming different book life, and different reagent cost. These analyses are discussed and shown in Appendix B of the EGU NO_X Mitigations Strategies Final Rule TSD and demonstrate that even under different operating assumptions, the variation in cost does not reach a point that would reverse EPA's finding regarding the appropriateness of this technology as part of this final rule's control stringency. Moreover, as discussed in section V.D of this document, EPA identifies appropriate mitigation strategies based on multiple factors—not solely on cost, and there is no indication that an individual unit's higher retrofit cost would obviate the appropriateness of retrofitting this standard and best practice technology at the unit. Finally, in prior rules and in the proposal, EPA recognized that some units will have higher cost and some will have lower cost relative the fleetwide representative value provided. Implementing the region and state reduction requirements through a mass-based trading program provides a means of alternative lower cost compliance for those sources particularly concerned about the higher retrofit cost at their unit.

Comment: Some commenters suggested that EPA's proposed representative cost for SCR pollution control is likely too high and overstates the true cost of such control. They also noted it aligns with agency precedent. These commenters claim that EPA's cost recovery factor is higher than necessary (thus inflating the cost) as it reflects a weighting of utility-owned to merchant-owned plants that is representative of the fleet, but not the unretrofitted fleet with this retrofit potential identified in this rule. They also noted that EPA's assumed interest rate informing the cost estimate was higher than the prime rate in June of 2022.

Response: EPA agrees that its approach for identifying representative cost thresholds is aligned with prior rules and agrees that its approach is reasonable. As the commenter points out, prime rates and cost recovery factors may indeed be lower in recent data than those assumed by EPA for future years. However, given the

[218] In the RIA, EPA has modeled the mass-based budgets that are premised on retrofit of SCR technology with the option of complying through other strategies, and finds that they are readily achievable through those other strategies.

volatility among these metrics, EPA believes its choices are appropriate to build cost estimates that are robust to future uncertainty, and if these cost input factors do materialize to be the lower values highlighted by commenter, then it will result in a lower cost assumed in this final rule, but would not otherwise alter any of the stringency identification or regulatory findings put forward in this final rule. EPA performed a cost sensitivity analysis in Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD which shows how cost for this technology would vary based on different assumed levels for this variable. This analysis shows that under lower interest rates such as those put forward by commenter, that technology cost would drop by approximately 15 percent relative to the representative values put forward in this rule.

f. Generation Shifting

At proposal, EPA considered intrastate emissions reduction potential from generation shifting across the representative dollar per ton levels estimated for the emissions controls considered in previous sections. 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.

The EPA recognizes that imposing a NO_X-control requirement on affected EGUs, like any environmental regulation, internalizes the cost of their pollution, which could result in generation shifting away from those sources toward other generators offering electricity at a lower pollution cost. If, in the context of a market-based allowance trading program form of implementation, the EPA imposes a preset emissions budget that is premised only on assumed installation, optimization, and continued operation of unit-specific pollution control technologies, with no accounting for the likely generation shift in the marketplace away from these higher-polluting sources, that preset emissions budget will contain more tons than would be emitted if the affected EGUs achieved the emissions performance level (on a rate basis) selected at step 3. Hence, EPA has previously quantified and required expected emissions reductions from generation shifting in prior transport rules to avoid undermining the program's incentive to install, optimize, and operate controls identified in the Agency's determinations regarding the requisite level of emissions control at Step 3. *See, e.g.,* 81 FR 74544–45; 76 FR 48280.

As in these prior rules, at proposal, the EPA did not identify generation shifting as a primary mitigation strategy and stringency measure on its own, but included emissions reductions from this strategy as it would be projected to occur in response to the selected emissions control stringency levels (and corresponding allowance price signals in step 4 implementation). For this rule's proposal, the EPA only specified emissions reductions from generation shifting in its preset budget calculations for 2023 and 2024. Because this rule's dynamic budget methodology applies the selected control stringency's emissions rates to the most recently reported heat input at each affected EGU, dynamic budgeting effectively serves a similar purpose to our ex ante quantification of emissions reduction potential from generation shifting for preset budgets in prior transport rules, *i.e.,* to adequately and continuously incentivize the implementation of the emissions control strategies selected at Step 3. Therefore, dynamic budgets under this rule's program moot the need to specify discrete emissions reduction potential from generation shifting for those control periods, as they automatically reflect whatever generation balance affected EGUs would determine in the marketplace inclusive of their response to the emissions performance levels imposed by this rule.

Comment: Commenters offered both support for and opposition against the inclusion of generation shifting at Step 3 analysis for EGUs. Those in support noted that inclusion of emissions reductions from generation-shifting is integral to the successful implementation of the pollution control measures identified in the selected control stringency at Step 3. Those opposed generally argued the EPA was overestimating reduction potential from generation shifting in light of recent volatility and high prices in the markets for lower emitting fuels such as natural gas. Commenters also noted the electrical grid in certain regions has constraints that would make generation shifting more difficult than the EPA assumed. Commenters also asserted that the EPA did not have the legal authority to require generation shifting.

Response: The EPA disagrees with these comments regarding our legal authority but notes this issue is not relevant for purposes of this final action. The EPA continues to believe it has authority under CAA section 110(a)(2)(D)(i)(I) to consider and require emissions reductions from generation shifting if the EPA were to find that strategy was necessary to eliminate significant contribution. However, based on circumstances currently facing affected EGUs, as well as the inherent strength of the dynamic budget methodology to automatically reflect the market-determined balance of generation across sources responding to this rule, the EPA is not specifying emissions reduction potential from generation shifting as a part of the Step 3 analysis, nor to require any emissions reductions from generation shifting in preset budgets formulated under Step 4 for any control period, for this final rule.

Currently observable market conditions (*e.g.,* fuel prices) present unusual uncertainty with respect to key economic drivers of generation shifting. The availability of emissions reductions through generation shifting, and the magnitude of those emissions, is dependent on the availability and cost of substitute generation. The primary driver of near-term generation shifting-based emissions reductions has been shifting to lower-emitting natural gas generation. Recent volatility and high prices in the natural gas market have increased the uncertainty and reduced the potential of this emissions control strategy at any given cost threshold in the near term. For example, Henry Hub natural gas prices went from under $3.00/mmBtu during most of the last decade to an average of nearly $8.00/mmBtu for the most recent (2022) ozone season before declining sharply at the start of 2023. The current volatility in natural gas prices reduces the availability of emissions reductions from generation shifting and make its identification and quantification too uncertain for incorporation into Step 3 emissions reduction estimates for this rulemaking.

The Step 4 dynamic budget-setting process of this rule obviates the need to specify and require discrete emissions reductions from generation shifting under Step 3. As discussed in section VI of this document, the EPA in this final rule will implement a budget-setting approach that relies on two components: first, we have calculated ''preset'' budgets that reflect the best information currently available about fleet change over the period 2023 through 2029. Second, beginning in 2026, dynamic state emissions budgets will be calculated that will reflect the balance of generation across sources reported to EPA by EGU operators. Between 2026 and 2029, the actual budget that will be implemented will reflect the greater of either the preset budget or the dynamic budget calculation; from 2030 onwards, the budgets will be set only through the dynamic budget calculation. This overall approach is well suited for a period of significant power sector transition driven by a variety of economic, policy, and regulatory forces and allows for the balance of generation in this period to adjust in response to these forces while nonetheless ensuring that the budgets will continuously incentivize the emissions control stringency identified at Step 3. See section VI.B.4 of this document for further discussion on the interaction of preset and dynamic budgets during the 2026–2029 time period. With these approaches, and on the present record before the Agency, we conclude that the estimation and incorporation of specified emissions reductions from generation shifting at Step 3 is not necessary to eliminate significant contribution from EGUs for the 2015 ozone NAAQS through this rule's program implementation.

In previous CSAPR rulemakings, the EPA included generation shifting in the budget setting process to capture those reductions that would occur through shifting generation as an economic response to the control stringency determined based on the selected NO_X control strategies. *See, e.g.,* 81 FR 74544–45. ''Because we have identified discrete cost thresholds resulting from the full implementation of particular types of emissions controls, it is reasonable to simultaneously quantify the reduction potential from generation shifting strategy at each cost level. Including these reductions is important, ensuring that other cost-effective reductions (*e.g.,* fully operating controls) can be expected to occur.'' EGU NO_X Mitigation Strategies Final Rule TSD (EPA–HQ–OAR–2015–0500–0554), at 11–12.

Commenters on this rule and prior transport rules have observed that using preset budgets to factor in generation shifting is flawed in that it results in EPA incorporating specific quantities of emissions reductions from discrete levels of generation shifting that are projected to occur but may in fact ultimately transpire differently in the marketplace. Commenters on this rule claim that other variables, such as constraints in transmission capacity or changes in fuel prices, can drive such differences in projected versus realized generation shifting, and these concerns are particularly exacerbated in a time of significant uncertainty around energy supplies and markets together with new laws passed by Congress (*e.g.,* the Infrastructure Investment and Jobs Act and the Inflation Reduction Act) driving the current transformation of the power sector. By refraining in this rule from specifying discrete emissions reductions from generation shifting in preset budgets and instead relying on a dynamic budgeting approach to reflect market-driven generation patterns, EPA ensures that its budgets remain sufficiently stringent over the long term to continually incentivize the emissions control stringency it determined to be cost-effective and therefore appropriate to eliminate significant contribution at Step 3. Thus, dynamic budgeting addresses the same concern that animated our use of generation shifting in the CSAPR rulemakings, but in doing so uses a market-following approach that will accommodate, over the long term, unforeseen drops or increases in heat input levels.

g. Other EGU Mitigation Measures

The EPA requested 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 and Final Rule TSDs discussed 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).

Comment: Some commenters emphasized that simple cycle combustion turbines play a significant role in downwind contribution, and they highlight that states such as New York have imposed emissions limits on these sources acknowledging their impact on downwind nonattainment. These commenters suggest that EPA pursue and expedite the implementation of these or similar mitigation measures.

Response: As explained in greater detail in the EGU NO_X Mitigation Strategies Final TSD, both the configuration and operation of this segment of the EGU fleet reflects significant variability among units and across time. In other words, one unit may have a capacity factor in a given year that is one hundred times greater than a similar unit in that same year, or even than its own capacity factor from a preceding year. This type of variability and heterogeneity make it unlikely that there is a single cost-effective control strategy across this fleet segment, and commenters did not provide evidence to the contrary. EPA's analysis discussed in the EGU NO_X Mitigation Strategies Final 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). EPA analysis estimates a representative cost of $22,000 per ton for dry low NO_X burners or ultra-low NO_X burners at these simple cycle combustion turbines, and over $100,000 per ton for SCR retrofit at some combustion turbines. Therefore, EPA does not identify any such uniform mitigation measure at Step 3 when estimating reduction potential.

Nonetheless, the EPA recognizes that these simple cycle combustion turbines may have cost-effective emissions-reduction opportunities. These units are included in the emissions trading program and therefore, as in prior transport rules, the program continues to subject them to an allowance holding requirement under this rule which will likely incentivize any available cost-effective NO_X reductions from these EGUs. For instance, emissions rates from these units in New York were considerably lower in 2022, when they faced a high allowance price, versus 2021, when the allowance price was much lower. Therefore, we find that the appropriate treatment of these units in this final rule is to continue to include them in the emissions trading program to incentivize cost-effective emissions reductions, but EPA does not find the magnitude or consistency of cost-effective mitigation potential to establish a specific increment of emissions reduction through a specific Step 3 emissions control determination. Moreover, while EPA's program will incentivize any available cost-effective reductions within this cadre of units (and such behavior is captured in its final program evaluation and modeling the *RIA*), it does not obviate the need for the other EGU cost-effective reductions elsewhere as suggested by some commenters.

2. Non-EGU or Stationary Industrial Source NO_X Mitigation Strategies

In the early stages of preparing the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact on downwind receptors' air quality and therefore the greatest impact in providing ozone air quality improvements in affected downwind states through reducing those emissions. Specifically, the EPA conducted a screening assessment focused on individual emissions units with >100 tpy of actual NO_X emissions in 23 upwind states. Once the industries were identified, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum ''Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'' (''Non-EGU Screening Assessment'' or ''screening assessment'') lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[219]

This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that potentially had the most impact in terms of the magnitude of emissions and potential for emissions reductions, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP.[220]

In this final rule, for purposes of this part of the Step 3 analysis, the EPA is retaining emissions control requirements for these industries and many of the emissions unit types included in the proposal. However, based on comments that credibly indicated in certain cases that emissions reduction opportunities are either not available for certain unit types or are at costs that are far greater than the EPA estimated at proposal, the EPA has changed the final rule to either remove or adjust the applicability criteria for such units. For a detailed discussion of the changes between the proposed FIP and this final rule, in emissions unit types included and in emissions limits, see section VI.C of this document. Tables I.B–2 through I.B–7 in section I.B of this document identify the emissions units and applicable emissions limitations, and Table II.A–1 in section II.A of this document identifies the industries included in the final rule.

For the final rule, to determine NO_X emissions reduction potential for the non-EGU industries and emissions unit types, with the exception of Solid Waste Combustors and Incinerators, we used a 2019 inventory prepared from the emissions inventory system (EIS) to estimate a list of emissions units captured by the applicability criteria for the final rule. For Solid Waste Combustors and Incinerators, the EPA estimated the list of covered units using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook.[221] Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain control technologies could meet the final emissions limits.[222] We did not run the Control Strategy Tool to estimate emissions reductions and costs and instead programmed the assessment using R.[223] Using the list of emissions units estimated to be captured by the final rule applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB),[224] the EPA estimated NO_X emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records.

The EPA recognized both at proposal and in the final rule that the cost per ton of emissions controls could vary by industry and by facility. The $7,500 marginal cost/ton threshold reflected in the Non-EGU Screening Assessment functioned as a relative, representative cost/ton level. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The value was used to identify potentially cost-effective controls for further evaluation.

In the final rule, partly in recognition of the many comments indicating widely varying cost-per-ton values across industries and facilities, the EPA has updated its analysis of costs for the covered non-EGU industries. This data is summarized in the Technical Memorandum ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' available in the docket. We further respond to comments on the screening assessment in section 2.2 of the response to comments document.

3. Other Stationary Sources NO_X Mitigation Strategies

As part of its analysis for this final 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) solid waste incineration units, (2) electric generating units less than or equal to 25 MW, and (3) cogeneration units. EPA's initial assessment did not lead it to propose inclusion of the units in these categories. However, EPA requested comment on whether any particular units within this category may offer cost-effective reduction potential.

Based on our request for comment, comments received, and our further evaluation, the EPA is including emissions limits and associated control requirements for the ozone season for solid waste incinerator units in this final rule, in line with the requirements we laid out for comment at proposal. Our analysis in this final rule confirms that these units have emissions reductions of a magnitude, degree of beneficial impact, and cost-effectiveness that is on par with the units in other industrial sectors included in this final rule.

[219] The memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.*

[220] The TSD for the proposed FIP is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.*

[221] The workbook is available here: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.*

[222] The Final Non-EGU Sectors TSD is available in the docket.

[223] R is a free software environment for statistical computing and graphics. Additional information is available here: *https://www.r-project.org/.*

[224] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

For electric generating units less than 25 MW and cogeneration units previously exempted from EGU emissions budgets established through ozone interstate transport rules, the EPA has determined that these units should not be treated as EGUs in this final rule.

The EPA provides a summary of these three segments, their emissions control opportunities, and potential air quality benefits in the following sections. Additional considerations are further discussed in the EGU NO_X Mitigation Strategies Final TSD and in the *RTC* Document.

a. Municipal Solid Waste Units

At proposal, the EPA solicited comments on whether NO_X emissions reductions should be sought from municipal waste combustors (MWCs) to address interstate ozone transport, specifically on potential emissions limits, control technologies, and control costs. The EPA requested comment on emissions limits of 105 ppmvd on a 30-day rolling average and a 110 ppmvd on a 24-hour block average based on determinations made in the June 2021 Ozone Transport Commission (OTC) *Municipal Waste Combustor Workgroup Report* (OTC MWC Report). *See* 87 FR 20085–20086. The OTC MWC Report found that MWCs in the Ozone Transport Region (OTR) are a significant source of NO_X emissions and that significant annual NO_X reductions could be achieved from MWCs in the OTR using several different technologies, or combination of technologies at a reasonable cost. The OTC MWC report is included in the docket for this action.

Comment: The EPA received multiple comments supporting the inclusion of emissions limits for MWCs in the final rule. Commenters noted that MWCs are significant sources of NO_X that contribute to ozone problems in the states covered by the proposal. Multiple commenters referenced the OTC MWC report to contend that NO_X emissions from MWCs could be significantly reduced at a reasonable cost. Some commenters reasoned that sources closer to downwind monitors, including MWCs, should be regulated as a more targeted approach and a means to prevent overcontrol of upwind sources. Commenters also noted that the OTC recently signed a memorandum of understanding (MOU) requesting that OTC member states develop cost effective solutions and select the strategy or combination of strategies, as necessary and appropriate, that provides both the maximum certainty and flexibility for that state and its MWCs. Additionally, multiple commenters noted that MWCs are often located in economically marginalized communities or communities of color. Lastly, one commenter stated that MWCs were arbitrarily excluded from the non-EGU screening assessment prepared for the proposal.

Response: As described in section VI.B.2 of the notice of proposed rulemaking, the EPA assessed emissions reduction potential from non-EGUs by preparing a screening assessment to identify those industries that could have the greatest air quality impact at downwind receptors. While the EPA did not prepare an updated non-EGU screening assessment in preparation for this final rule, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and determined that MWCs should be included in this rulemaking. A discussion of this analysis for MWCs is available in the *Municipal Waste Combustor Supplement to February 28, 2022 Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* which is available in the docket for this rule.

Considering EPA's conclusion that MWCs should be included in this final rule if EPA applied the same criteria developed in the screening assessment for proposal, the findings from the OTC MWC report and recent MOU, the fact that many state RACT NO_X rules apply to MWCs, and information received during public comment, the EPA finds that MWCs should be included in this final rule. Thus, the EPA is finalizing NO_X emissions limits and compliance assurance requirements for large MWCs as defined in the regulatory text at § 52.46 and as described in this section.

Comment: Some commenters did not support the inclusion of emissions limits for MWCs in the final rule. Some commenters suggested that the inclusion of NO_X limits in a FIP is not necessary to continue to reduce NO_X emissions from MWCs or to address interstate transport problems. Some commenters noted that many of the MWCs in the states covered by the proposal are already subject to RACT-based NO_X emissions limits that are below the current Federal NSPS NO_X emissions limits for MWCs under 40 CFR part 60, subparts Cb and Eb. One commenter noted that MWCs do not always account for a large percentage of statewide NO_X emissions. Others suggested that voluntary industry actions are also driving downward trends of NO_X emissions for some MWCs. Some commenters also asserted that regulation could interfere with state waste reduction policies and associated environmental considerations.

Response: Regarding the comments that some MWCs are already subject to RACT NO_X emissions limits, the EPA acknowledges that some states included in this rulemaking have promulgated RACT NO_X emissions limits that apply to certain MWCs, including some that are lower than current MWC NSPS NO_X emissions limits. The EPA does not consider a source to be exempt from this rulemaking just because the source may be subject to other regulatory requirements. As noted, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and has concluded that MWCs should be included in this rulemaking. In considering the emissions limits that are being finalized in this rulemaking, the EPA reviewed existing state RACT rules as described in section VI.C.6 of this document and the ''Technical Support Document (TSD) for the Final Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Mar. 2023), hereinafter referred to as Final Non-EGU Sectors TSD. We note that sources already subject to RACT NO_X emissions limits that are equal to or more stringent than the limits finalized in this rulemaking will have the option to streamline regulatory requirements through the Title V permitting process.

Regarding the statement that regulation could interfere with state waste reduction policies and associated environmental considerations, the EPA acknowledges that MWCs serve an important role in municipal solid waste management programs, and that many function as cogeneration facilities that produce electrical power for the power grid. The EPA also analyzed control costs and determined that the required NO_X emissions limits for MWCs can be achieved at a reasonable cost, as described in section VI.C.6 of this document, the Final Non-EGU Sectors TSD, and the OTC MWC Report. Although the EPA does not expect these regulations to disrupt the ability of the industry to provide municipal solid waste and electric services, to the extent a facility is unable to comply with the standards due to technical impossibility or extreme economic hardship, the final rule includes provisions for facility operators to apply for a case-by-case alternative emissions limit. *See* section VI.C of this document and 40 CFR 52.40(d). In addition, for MWC facilities that are unable to comply with the standard by the 2026 ozone season, the final rule includes provisions for requesting limited extensions of time to comply. *See* section VI.C and 40 CFR 52.40(c).

b. Electric Generating Units Less Than or Equal to 25 MW

The EPA has historically not included control requirements for emissions for electric generating units less than or equal to 25 MW of generation 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 percent 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 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 emissions reductions from these small EGU sources as part of this rule. For instance, as explained in the EGU NO_X Mitigation Strategies Final 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.[225] Moreover, the EPA estimates that under 6 percent of nationwide EGU emissions come from units that are less than 25 MW and not covered by current applicability criteria due to this size exemption threshold. Therefore, the EPA is not finalizing any emissions reductions for these units.

Comment: EPA received comment supporting the continued application of the 25 MW threshold.

Response: Consistent with prior rules, the proposal, and stakeholder comment, EPA is continuing to apply its 25 MW applicability threshold for EGUs in this rulemaking. EPA did not find compelling comment to reverse its determination that (1) these sources offer low potential reductions, (2) have relatively high cost per ton, and (3) have high monitoring and other compliance burdens.

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 altering in this rulemaking (*see* section VI.B.3 of this document)—exempt some cogeneration units from coverage as EGUs under the trading program. The EPA is finalizing 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 the Group 3 emissions trading program. However, to the extent a cogeneration unit meets the applicability criteria for industrial non-EGU boilers covered by this rule, that unit will be subject to the relevant requirements and is not exempted by virtue of being a cogeneration unit.

According to information contained in the EPA's Combined Heat and Power Partnership's document "Catalog of CHP Technologies",[226] there are 4,226 CHP installations in the U.S. providing 83,317 MWe of electrical capacity. Over 99 percent 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 herewith 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 rich burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lb/mmBtu. NO_X emissions from lean burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2 lb/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 lb/mmBtu.

Under the final 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. 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

[225] 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.

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

power. 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 requested comment on requiring fossil fuel-fired boilers in the non-EGU industries identified in section VI.C of this document 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 rulemaking to fossil fuel-fired boilers at facilities in the same non-EGU industries that do not serve electricity generators.

Comment: Some stakeholders support the continued exclusion of qualifying cogenerators from the EGU program, but suggested they be regulated as non-EGUs if they don't fit the EGU applicability criteria.

Response: The EPA agrees that there is no basis within the four-step framework to exempt cogeneration units that fall under the applicability criteria of the final rule for non-EGU boilers simply because they are cogeneration units. While cogeneration units do have environmental benefits as noted at proposal, some cogeneration unit-types, particularly boilers, are estimated to have NO_X emissions that would otherwise meet this rule's criteria at Step 3 for constituting ''significant contribution.'' These units can meet the emissions limits that are otherwise finalized for these unit types, and the EPA does not find a basis to exclude them simply because they may have other environmentally-beneficial attributes.

These emissions limits are set forth in section VI.C.5 of this document. Therefore, the final requirements for non-EGUs do not exempt cogeneration units and any cogeneration emissions units meeting the applicability criteria for non-EGUs will be subject to the final emissions limits for the appropriate non-EGU emissions unit. Based on EPA's review of available data, across all of the non-EGU industries covered by this rule, there are four cogeneration boilers (two in Pulp and Papermill and two in Basic Chemical Manufacturing) that would meet the final rule's applicability criteria for non-EGU units and are included in the analysis of non-EGU emissions reduction potential in section V.C.2 of this document.

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 section 209), 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 final 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) [227] 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.[228]

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.[229] 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).

Most recently, EPA finalized more stringent emissions standards for NO_X and other pollution from heavy-duty trucks (Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards, 88 FR 4296, January 24, 2023). These standards will take effect beginning with model year 2027. 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.[230] Reducing heavy-duty vehicle emissions nationally will improve air quality where the trucks are operating as well as downwind. The EPA's existing regulatory program for mobile sources will continue to reduce NO_X emissions into the future.

Comment: The EPA received comments on ozone-precursor emissions from mobile sources, including cars, trucks, trains, ships, and planes. Commenters broadly encouraged the EPA to require emissions reductions from mobile sources in this rule. Commenters stated that the transportation sector plays a significant role in NO_X pollution and ozone formation and urged the EPA to finalize emissions reductions for the transportation sector that will enable attainment of the 2015 ozone NAAQS. Some commenters noted that high proportions of NO_X emissions in various upwind states are attributable to the transportation sector, and stated that EPA should have targeted emissions reductions from mobile sources first before requiring more stringent emissions controls from stationary sources in the same upwind states.

Response: The EPA agrees with commenters that a variety of sources, including mobile sources in the transportation sector, produce NO_X emissions that contribute to ozone air quality problems across the U.S. This rule, as with prior interstate transport actions, does not ignore those emissions, and it credits those on-the-books measures of states and the Federal Government within the four-step framework by including emissions and

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

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

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

[230] 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.*

emissions reductions from these sources in the emissions inventory for air quality modeling, which informs Steps 1 and 2 of this analysis. Thus, this rule accurately represents emissions from mobile sources that are used to evaluate the contribution of states to ozone air quality problems in other states. See section IV.C of this document.

The EPA notes that its Step 3 analysis for this FIP does not assess additional emissions reductions opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing these emissions at the Federal level. EPA's various Federal mobile source programs, summarized above in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules 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 the EPA's authority to address such emissions through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *See also* 86 FR 23099.[231] In any case, the existence of mobile source emissions noted by commenters does not lead to the conclusion that the EPA must require mobile source reductions in this rule or that the EPA has not properly identified ''source[s] or other type[s] of emissions activity'' in upwind states that ''significantly contribute'' for purposes of the Good Neighbor Provision. The EPA is committed to continuing the effective implementation and enforcement of current mobile source standards and continuing its efforts on new standards. The EPA will continue to work with state and local air agencies to incorporate emissions reductions from the transportation sector into required ozone attainment planning elements.

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 V.A of this document, 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 V.B.1 of this document), 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.[232] The EGUs in the state are sufficiently well-controlled resulting in the lowest fossil-fuel emissions rate and highest share of renewable generation among the 23 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 emissions reductions required to eliminate significant contribution from any EGU sources in California.

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

TABLE V.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
Alabama	6,412	32	32	32
Arkansas	8,955	28	28	28
Illinois	7,721	70	70	247
Indiana	13,298	856	856	858
Kentucky	13,900	299	901	901
Louisiana	9,974	515	515	611
Maryland	1,214	0	0	8
Michigan	10,746	4	4	19
Minnesota	5,643	98	98	139
Mississippi	6,283	73	984	984
Missouri	20,094	7,339	7,339	7,497
Nevada	2,372	4	4	4
New Jersey	915	143	143	143
New York	3,977	64	64	64
Ohio	10,264	1,154	1,154	1,154
Oklahoma	10,470	199	890	890
Pennsylvania	8,573	336	336	436
Texas	41,276	909	909	1,142
Utah	15,762	7	7	7
Virginia	3,329	164	242	263
West Virginia	14,686	554	1,099	1,380

[231] This is not to say that states lack other options to reduce emissions from mobile sources. For example, a general list of types of transportation control measures can be found in CAA section 108(f). In addition, in accordance with section 177, states may (but are not required to) adopt California vehicle emissions standards for which a waiver has been granted from the preemption provisions in section 209(a). States that decide to adopt California vehicle emissions standards may also choose to submit those standards to be included as a part of their SIP.

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

TABLE V.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2023—Continued

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
Wisconsin	6,321	7	7	26
Total	222,184	12,854	15,681	16,832

* The EPA shows reduction potential from state-of-the-art LNB upgrade as near-term emissions controls, but explains in section V.B and VI.A of this document that this reduction potential would not be implemented until 2024.

TABLE V.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
Alabama	6,371	32	32	32	604
Arkansas	8,728	28	28	28	4,697
Illinois	6,644	70	70	230	1,281
Indiana	9,468	768	768	770	1,333
Kentucky	13,211	299	739	739	5,303
Louisiana	9,704	515	515	611	5,894
Maryland	901	51	51	59	59
Michigan	7,790	4	4	19	1,959
Minnesota	4,197	98	98	139	1,613
Mississippi	6,022	73	984	984	3,938
Missouri	18,612	7,339	7,339	7,497	11,231
Nevada	1,146	4	4	4	4
New Jersey	915	143	143	143	143
New York	3,977	64	64	64	589
Ohio	9,083	1,154	1,154	1,154	1,154
Oklahoma	10,259	199	890	890	5,968
Pennsylvania	8,362	352	352	452	1,204
Texas	39,684	909	909	1,142	15,980
Utah	9,930	7	7	7	7,338
Virginia	3,019	164	242	263	646
West Virginia	13,185	401	947	1,227	3,507
Wisconsin	5,016	7	7	26	623
Total	196,225	12,680	15,346	16,480	75,067

* The EPA shows all emissions reduction potential identified for assumed SCR retrofits in the Step 3 analytic year 2026, but explains in sections V.B and VI.A of this document that for Step 4 implementation this emissions reduction potential will be phased in during the 2026 and 2027 ozone season control periods.

2. Non-EGU or Industrial Source Emissions Reduction Potential

As described in the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the CMDB, to estimate NO_X emissions reductions and costs for the year 2026. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Table V.C.2–1 summarizes the industries, estimated emissions unit types, assumed control technologies, estimated annual costs (2016$), and estimated ozone season emissions reductions in 2026, and Table V.C.2–2 summarizes the estimated reductions by state.

TABLE V.C.2–1—BY INDUSTRY IN 2026, ESTIMATED EMISSIONS UNIT TYPES, ASSUMED CONTROL TECHNOLOGIES, ANNUAL COSTS (2016$), AND ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS)

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Annual costs (2016$)	Ozone season emissions reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	385,463,197	32,247
Cement and Concrete Product Manufacturing.	Kiln	SNCR	10,078,205	2,573
Iron and Steel Mills and Ferroalloy Manufacturing.	Reheat Furnaces	LNB	3,579,294	408
Glass and Glass Product Manufacturing	Furnaces	LNB	7,052,088	3,129
Iron and Steel Mills and Ferroalloy Manufacturing.	Boilers	SCR, LNB + FGR	8,838,171	440
Metal Ore Mining			621,496	18
Basic Chemical Manufacturing			49,697,848	1,748
Petroleum and Coal Products Manufacturing.			5,128,439	147
Pulp, Paper, and Paperboard Mills			62,268,540	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	38,949,560	2,071
Totals			571,676,839	44,616

TABLE V.C.2–2—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS) BY UPWIND STATE IN 2026

State	2019 OS emissions *	OS NO_X reductions
AR	8,790	1,546
CA	16,562	1,600
IL	15,821	2,311
IN	16,673	1,976
KY	10,134	2,665
LA	40,954	7,142
MD	2,818	157
MI	20,576	2,985
MO	11,237	2,065
MS	9,763	2,499
NJ	2,078	242
NV [233]	2,544	0
NY	5,363	958
OH	18,000	3,105
OK	26,786	4,388
PA	14,919	2,184
TX	61,099	4,691
UT	4,232	252
VA	7,757	2,200
WV	6,318	1,649
Totals	302,425	44,616

* The 2019 OS season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

In Table V.C.2–3 by industry and emissions unit type, the EPA provides a summary of the control technologies applied and their average costs across all of the non-EGU emissions units. The average cost per ton values range from $939 to $14,595 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.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	4,981
Cement and Concrete Product Manufacturing	Kiln	SNCR	1,632

[233] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. *See* section III.B.1.d.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS—Continued

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,656
Glass and Glass Product Manufacturing	Furnaces	LNB	939
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR or LNB + FGR	8,369
Metal Ore Mining			14,595
Basic Chemical Manufacturing			11,845
Petroleum and Coal Products Manufacturing			14,582
Pulp, Paper, and Paperboard Mills			14,134
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	7,836
Overall Average Cost/Ton			5,339

Refer to the memorandum titled "Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs" for additional estimates—including by industry and by state. These estimates are proxy estimates, and the EPA also did not prepare detailed engineering analyses for the industries, facilities, and individual emissions units identified for the final rule. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment.

Comment: Regarding the marginal cost threshold of $7,500/ton used to assess potential emissions reductions in the non-EGU screening assessment prepared for proposal, commenters raised a range of questions, including (1) why the EPA used a marginal cost threshold that is much higher than the $2,000/ton threshold used in the 2021 Revised CSAPR Update Rule, (2) why the EPA used a "one size fits all" approach for addressing the estimated cost and actual emissions reductions achievable, particularly for existing sources of NO_X emissions, (3) why the EPA set a $7,500/ton marginal cost threshold for all non-EGUs, despite acknowledging the heterogeneity of industry, emissions unit types and control options and failing to consider the actual costs associated with achieving the proposed reductions at different types of emissions units in order to artificially inflate the marginal cost threshold and to justify otherwise cost-prohibitive NO_X control technologies. Commenters also stated that controls for their industry are not cost-effective using the EPA's presumptive value of $7,500/ton and that the value may not be technically feasible to apply to existing sources that would have to retrofit controls.

Response: The EPA notes that the primary purpose of the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) was to identify potentially impactful industries and emissions unit types for further evaluation.[234] In the non-EGU screening assessment memorandum we presented an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026.

As noted in section V.D. of this document, at proposal the EPA found that based on data available at that time and for the purposes of the non-EGU screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Also, the $7,500 marginal cost-per-ton threshold is higher than the cost-per-ton value used in the Revised Cross-State Air Pollution Rule Update because that rulemaking assessed significant contribution for the less protective 2008 ozone NAAQS, and it is reasonable when assessing significant contribution associated with the more protective 2015 ozone NAAQS, that a potentially more costly universe of emissions controls and related potential reductions should be included in the analysis.[235] Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed.

While the potentially impactful industries (identified in Step 1 of the analytical framework presented in the non-EGU screening assessment) were directly used, the proxy estimates for emissions unit types, emissions reductions, and costs from the non-EGU screening assessment were not directly used to establish applicability thresholds and emissions limits in the proposal. To further evaluate the impactful industries and emissions unit types and establish the proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies (*e.g.,* Ozone Transport Commission, Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions, October 17, 2012), rules in approved SIP submittals, consent decrees, and permit limits.[236]

[234] The non-EGU screening assessment memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150*.

[235] As the amount of air pollution that is allowed in the ambient air is reduced (i.e., when a NAAQS is revised), it is reasonable to expect that further emissions reductions may be necessary to bring areas into attainment with that more protective standard. At the same time, the available remaining emissions reduction opportunities will likely have become more costly compared to a prior period, because other CAA requirements, including such as earlier transport rules, will have consumed those emissions reduction opportunities that were the least costly. The EPA noted this same possibility in the original CSAPR rulemaking, *see* 76 FR 48210.

[236] This review is detailed in the Final Non-EGU Sectors TSD available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

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 finalizes a determination regarding the appropriate level of uniform NO_X control stringency that would collectively eliminate significant contribution to downwind nonattainment and maintenance receptors. Based on the air quality results presented in this section, we find that the emissions control strategies that were identified and evaluated in sections V.B and V.C of this document and found to be both cost-effective and feasible, deliver meaningful air quality benefits through projected reductions in ozone levels across the linked downwind nonattainment and maintenance receptors in the relevant analytic years 2023 and 2026. Further, EPA finds the emissions control strategies in upwind states that would deliver these benefits to be widely available and in use at many other similar EGU and non-EGU facilities throughout the country, particularly in those areas that have historically or now continue to struggle to attain and maintain the 2015 ozone NAAQS. Applying these emissions control strategies on a uniform basis across all linked upwind states continues to constitute an efficient and equitable solution to the problem of allocating upwind-state responsibility for the elimination of significant contribution. This approach continues to effectively address the ''thorny'' causation problem of interstate pollution transport for regional-scale pollutants like ozone that transport over large distances and are affected by the vagaries of meteorology. *EME Homer City,* 572 U.S. at 514–16. It requires the most impactful sources in each state that has been found to contribute to ozone problems in other states to come up to minimum standards of environmental performance based on demonstrated NO_X pollution-control technology. *Id.* at 519. When the effects of these emissions reductions are assessed collectively across the hundreds of EGU and non-EGU industrial sources that are subject to this rule, the cumulative improvements in ozone levels at downwind receptors, while they may vary to some extent, are both measurable and meaningful and will assist downwind areas in attaining and maintaining the 2015 ozone NAAQS.

In addition to the findings of cost-effectiveness, feasibility and widespread availability that support EPA's identification of the appropriate level of emissions-control stringency at Step 3 discussed in sections V.B and V.C, the findings regarding air quality improvement in this section—as in prior transport rules—are a central component of our Step 3 analytic findings as to the definition of ''significant contribution.'' EPA's assessment of air quality improvement for all of the emissions control strategies included shows continued air quality improvement with each additional control strategy measure. Within the group of selected control strategies for EGUs and non-EGUs no clear ''knee-in-the-curve'' is evident; *i.e.,* there is no point at which there is a noticeable decline in the rate of air quality improvement up through the control stringency level selected. However, if EPA were to go beyond the selected control stringency through inclusion of additional EGU or non-EGU NO_X mitigation technologies for the covered sources and unit-types that are, at least on the record of this action, not widely available, uncertain or untested, and/or far more costly, a ''knee-in-the-curve'' does materialize, where the incremental air quality benefit per dollar spent per ton on mitigation measures plateaus even as costs increase dramatically. In the Revised CSAPR Update, EPA explained that a knee in the curve ''is not on its own a justification for not requiring reductions beyond that point,'' 86 FR 23107, but does indicate that it is a useful indicator for informing potential stopping points. The observation that no ''knee-in-the-curve'' materializes at the stringency levels up through that selected by EPA supports EPA's identified control stringency.

Further, as the Supreme Court has 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. While the ultimate purpose of the good neighbor provision is to eliminate significant contribution and not necessarily to resolve downwind areas' nonattainment and maintenance problems, we have evaluated the expected attainment status at each identified receptor as we examine the air quality effects of the different emissions control strategies identified. As discussed further in this section, the EPA notes that multiple receptors shift into projected attainment status or shift from projected nonattainment to maintenance status up through the stringency level ultimately selected by EPA. (And all receptors show improvement in air quality even if their status does not change.) These analytic findings at Step 3 cement EPA's identification of the selected EGU and non-EGU mitigation measures as the appropriate control stringency to fulfill its statutory obligation to eliminate significant contribution for the 2015 ozone NAAQS for the covered states. The EPA also evaluated whether the final 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 of NAAQS air quality contribution threshold at a lower cost threshold. The Agency finds no overcontrol from this rule. See section V.D.4 of this document.

1. EGU Assessment

For EGUs, the EPA examined the emissions reduction potential associated with each EGU emissions control technology (presented in section V.C.1 of this document) 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 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 starting in the 2026 ozone season at $11,000 and $7,700 per ton respectively. For all but 3 of the affected states (Alabama, Minnesota, and Wisconsin, which are no longer linked in 2026 at Steps 1 and 2 in EPA's base case air quality modeling for this final rule), EPA's evaluation shows that the effective emissions rate performance across EGUs consistent with the full 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 Final Rule TSD for details).

To assess downwind air quality impacts for the nonattainment and maintenance receptors identified in section IV.D of this document, 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 ''fair share'' of the responsibility for resolving a nonattainment or maintenance problem as a part of the over-control evaluation.[237]

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 Final 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 0.06 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 no receptors switch from maintenance to attainment or from nonattainment to maintenance with these mitigation strategies in place. Table V.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 0.47 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 Larimer County, Colorado (Monitor 080690011), switching from maintenance to attainment and two receptors (one in Fairfield County, Connecticut (Monitor 90013007), and one in Galveston, Texas (Monitor ID 481671034)) switching from nonattainment to maintenance with these mitigation strategies in place.[238] Table V.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 Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

[237] For EGUs, this analysis for the Connecticut receptors shows no EGU reduction potential in Connecticut 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.

[238] 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 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 action are further discussed in sections V.D.3 and V.D.4 of this document.

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

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
40278011	Arizona	Yuma	70.36	70.34	72.05	72.04
80350004	Colorado	Douglas	71.12	71.10	71.71	71.70
80590006	Colorado	Jefferson	72.63	72.61	73.32	73.31
80590011	Colorado	Jefferson	73.29	73.27	73.89	73.87
80690011	Colorado	Larimer	70.79	70.78	71.99	71.98
90010017	Connecticut	Fairfield	71.62	71.56	72.22	72.16
90013007	Connecticut	Fairfield	72.99	72.90	73.89	73.80
90019003	Connecticut	Fairfield	73.32	73.25	73.62	73.55
90099002	Connecticut	New Haven	70.61	70.51	72.71	72.61
170310001	Illinois	Cook	68.13	68.11	71.82	71.80
170314201	Illinois	Cook	67.92	67.88	71.41	71.37
170317002	Illinois	Cook	68.47	68.37	71.27	71.17
350130021	New Mexico	Dona Ana	70.83	70.82	72.13	72.12
350130022	New Mexico	Dona Ana	69.73	69.72	72.43	72.42
350151005	New Mexico [b]	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	70.59	70.52	72.69	72.62
481210034	Texas	Denton	69.93	69.88	71.73	71.68
481410037	Texas	El Paso	69.82	69.81	71.43	71.41
481671034	Texas	Galveston	71.82	71.70	73.13	73.01
482010024	Texas	Harris	75.33	75.25	76.93	76.85
482010055	Texas	Harris	71.19	71.10	72.20	72.10
482011034	Texas	Harris	70.32	70.25	71.52	71.45
482011035	Texas	Harris	68.01	67.94	71.52	71.45
490110004	Utah	Davis	71.88	71.87	74.08	74.07
490353006	Utah	Salt Lake	72.48	72.47	74.07	74.06
490353013	Utah	Salt Lake	73.21	73.20	73.71	73.70
550590019	Wisconsin	Kenosha	70.75	70.65	71.65	71.55
551010020	Wisconsin	Racine	69.59	69.46	71.39	71.25
551170006	Wisconsin	Sheboygan	72.64	72.46	73.54	73.36
Average AQ Change Relative to Base (ppb)						0.06
Total PPB Change Across All Receptors Relative to Base [c]						1.58

Table Notes:

[a] The EPA notes that the design values reflected in tables V.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 Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in tables V.D.1–1 and 1–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling

[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 VIII of this document provides a more complete picture of the air quality impacts of the final rule.

TABLE V.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	69.87	69.84	71.47	71.44
80590006	Colorado	Jefferson	71.70	71.36	72.30	71.95
80590011	Colorado	Jefferson	72.06	71.59	72.66	72.19
80690011	Colorado	Larimer	69.84	69.54	71.04	70.73
90013007	Connecticut	Fairfield	71.25	70.98	72.06	71.78
90019003	Connecticut	Fairfield	71.58	71.34	71.78	71.54
350130021	New Mexico	Dona Ana	70.06	69.89	71.36	71.19
350130022	New Mexico	Dona Ana	69.17	69.00	71.77	71.60
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.96	72.02	71.06
481671034	Texas	Galveston	71.29	70.02	72.51	71.22
482010024	Texas	Harris	74.83	73.86	76.45	75.46
490110004	Utah	Davis	69.90	69.34	72.10	71.52
490353006	Utah	Salt Lake	70.50	69.96	72.10	71.55
490353013	Utah	Salt Lake	71.91	71.45	72.31	71.84
551170006	Wisconsin	Sheboygan	70.83	70.51	71.73	71.41
Average AQ Change Relative to Base (ppb)						0.47
Total PPB Change Across All Receptors Relative to Base (ppb)						7.04

Figures 1 and 2 to section V.D.1 of this document, included in Appendix I of the Ozone Transport Policy Analysis Final 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 V.D.1 of this document reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to section V.D.1 of this document 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 V.D.1 of this document. 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 technologies. While all major technology breakpoints identified in sections V.B and V.C of this document show continued air quality improvements at problematic receptors and at cost and technology 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 uniform control stringency 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 66 percent 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.[239] Similarly, the Clean Air Interstate Rule established emissions reductions requirements in 2006 that assumed SCR would be installed on another 58 units (15 GW) 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.[240]

Basing emissions 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 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-fired generating resources in states along the Northeast Corridor such as Connecticut, Delaware, New Jersey, New York, and Massachusetts all being retrofitted with SCR.[241] The Maryland Code of Regulations requires coal-fired sources to operate existing SCR controls or install SCR controls by specified dates.[242] 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.[243] Unit-level 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.[244]

As shown in Figure 1 to section V.D.1 of this document,[245] 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 V.D.1 of this document[246] highlights (1) the continuous connection between identified emissions 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 determination to include SCR and SNCR optimization as part of the identified near-term control stringency, including:

[239] 63 FR 57448.

[240] 71 FR 25345.

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

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

[243] *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.*

[244] *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.*

[245] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[246] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

- 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 EGU emissions reduction potential and associated air quality improvements estimated to start in 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 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 is projected to result in nearly 73,000 tons of NO_X reduction (approximately 40 percent of the 2026 baseline level) for the 19 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 receptor for the 2015 ozone NAAQS. Figure 2 to section V.D.1 of this document [247] 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 emissions mitigation measures examined here fail to produce corresponding downwind air quality improvements.

The EPA is determining that the appropriate EGU control stringency is commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades for those states linked to downwind nonattainment or maintenance receptors 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 V.B of this document and in the EGU NO_X Mitigation Strategies Final 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 combined cycle and simple cycle combustion turbines). The emissions 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 units (rather than different pollution control technologies). 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 in this section, the EPA did analyze the cost, potential reductions, and air quality impact of these additional measures to affirm that they do not merit inclusion in the final stringency for this action. That analysis shows the potential emissions reductions and air quality improvements from these additional measures occur beyond a notable ‘‘knee-in-the-curve’’ breakpoint. 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 capturing this effect (located in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD) illustrates the significant decline in cost-effectiveness of reductions if these measures had been included in EPA's final stringency.[248]

2. Non-EGU Assessment

Using a 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database, the EPA estimated NO_X emissions reductions and costs for the year 2026. Given the EPA's conclusion that the 2026 ozone season is the earliest date by which the required controls can be installed across the identified non-EGU industries, the EPA assessed the effects of these controls in 2026 under its multi-factor test. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled ‘‘Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs’’ available in the docket. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control

[247] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[248] This is not to discount the potential effectiveness of these or other NO_X mitigation strategies outside the context of this rulemaking, which addresses regional ozone transport on a nationwide basis based on the present record. 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 finds on the present record that this rule is a complete remedy to the problem of interstate transport for the 2015 ozone NAAQS for the covered states, 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).

technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from, and costs to meet, the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

After reviewing public comments and updating some of the data used to provide an accurate assessment of the likely potential emissions reductions that could be achieved from the identified emissions units in the industries analyzed for proposal, the EPA finds that in general, these emissions reductions (with some modifications from proposal) are necessary to eliminate significant contribution at Step 3. The EPA's use of the analytical framework presented in the non-EGU screening assessment to identify potentially impactful industries and emissions unit types in the proposal remains valid. The EPA's criteria were intended to identify industries and emissions unit types that on a broad scale impact multiple receptors to varying degrees. The EPA focused its non-EGU screening assessment on (1) emissions and potential emissions reductions from these industries and emissions units and (2) the potential impact that emissions reductions from those industries and emissions units could deliver to the receptors.

While commenters criticized the analytical framework in the non-EGU screening assessment for assuming potentially unachievable emissions reductions at Step 3, or for not corresponding to a precise list of emissions units that would be covered at Step 4, these comments did not offer an alternative methodology for the Step 3 analysis to identify those industries and emissions units that potentially have the greatest impact and therefore should be scrutinized more closely for emissions reduction opportunities.[249] Further, contrary to some commenters' assertions, the EPA's assessment did not result in an unbounded scope of regulation of industrial sources. Of the approximately 40 industries defined by North American Industry Classification System codes the EPA analyzed, only seven industries were identified as having emissions and potential emissions reduction opportunities that met the EPA's air quality criteria for further assessment.

At proposal, the EPA found that based on data available at that time and for the purposes of the screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. For example, in the EGU analysis, the $11,000/ton average cost threshold for an SCR retrofit represents a range of SCR retrofit costs for units for which the 90th percentile cost-per-ton is roughly $21,000. See section V.B.a of this document. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. We respond briefly to comments regarding the use of the $7,500/ton threshold in section V.C of this document. Comments regarding the screening assessment are further addressed in section 2.2 of the response to comments document in the docket.

Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed. However, the EPA nonetheless finds that, with some adjustments from proposal, the overall mix of emissions controls it identified at proposal is appropriate to eliminate significant contribution to nonattainment or interference with maintenance in downwind areas. In the final analysis, we find that the average cost-per-ton of emissions reductions across all non-EGU industries in this rule generally ranges from approximately $939/ton to $14,595/ton, with an overall average of approximately $5,339/ton. *See* memorandum titled "Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs," available in the docket.

Nonetheless, overall the EPA finds that the range of cost-effectiveness values for non-EGU industries and emissions units compares favorably with the values used to evaluate EGUs. As discussed in the preceding paragraphs, the representative cost for EGUs to retrofit SCR is $11,000/ton. This reflects a range of cost estimates, with $20,900/ton reflecting the 90th percentile of units (see section V.B.a of this document). The higher end of the estimated average cost range for certain non-EGU industrial emissions units is also in that range. While specific emissions units may have higher costs associated with installing pollution control technologies than other similar unit types, this does not in itself undermine the Agency's conclusion that a level of emissions control associated with a specific emissions limit or control technology is appropriate to require across the linked upwind state region, in light of the overall emissions reductions and air quality benefits at downwind receptors that those controls are projected to deliver.

We note that the non-EGU control cost estimates in this final rule were based on historical actual emissions. This can affect the presentation of cost-per-ton values at the unit level, and it would not be appropriate to abandon uniform control stringency among like units in the covered industries across or within upwind states based on such cost differentials.

The EPA finds it appropriate to require a uniform level of emissions control across similar emissions unit types to, among other things, prevent two potential outcomes related to shifting production, either between units within the same facility or between units at different facilities. First, if some units were exempted from control requirements because of historically low actual emissions, there is a risk that source owners or operators may shift production to these specific units, increasing their utilization and resulting in emissions increases from these units. Second, if some owners or operators were able to avoid the control requirements of the final rule on this basis, they could gain a competitive advantage vis-à-vis other facilities within their respective industries. Production could shift from units at another facility subject to the control requirements to the units that avoided control requirements (and thus avoid costs the regulated facility should bear), potentially resulting in emissions increases. The effect of such an approach in such circumstances would be mere emissions shifting rather than the elimination of significant

[249] For example, while the EPA has found it appropriate to limit the scope of emissions units that would be subject to emissions limits and controls in the iron and steel industry in light of comments regarding certain sources' inability to meet the EPA's proposed emission limits, this does not alter the EPA's determination that this industry is an impactful industry and that certain emissions controls should still be required.

contribution. Finally, as we have explained in prior transport actions, the cost-effectiveness figure is not the only factor that the agency considers at Step 3, *see* 86 FR 23073, and if used in isolation to make a policy decision without considering other information, could produce a result that is inconsistent with the objective of ensuring significant contribution is eliminated.[250]

In addition to our evaluation of cost-effectiveness on a cost per ton basis, the EPA's determination at Step 3 for non-EGUs is also informed by the overall level of emissions reductions that will be achieved across the region and the effect those reductions are projected to have on air quality at the downwind receptors (discussed more later in this section). We are also influenced by the fact that these emissions control strategies for non-EGUs are generally well demonstrated to be feasible on many existing units, as established through our review of consent decrees, permits, RACT determinations, and other data sources. These levels of emissions control have in many cases already been required by states with downwind nonattainment areas for the 2015 ozone NAAQS.

The EPA determined that, for 2026, the incremental average air quality improvement at receptors relative to the EGU case when SCR post-combustion controls were installed was 0.19 ppb when non-EGU controls were applied, based on the Step 3 analysis. The total average air quality improvement was 0.66 ppb when the non-EGU improvement was added to the EGU improvement, meaning that the non-EGU increment accounts for about 29 percent of this average air quality improvement. In general, the air quality results from non-EGU emissions reductions yield additional important downwind benefits to the air quality benefits of the EGU strategy. For example, the total ppb improvement summed over all of the receptors from EGUs was 7.04 ppb and the non-EGU increment adds another 2.82 ppb of improvement bringing the total to 9.87 (when accounting for rounding). Non-EGUs account for 29 percent of this total air quality improvement as well. Further, these figures should not be considered in isolation; EPA is not comparing EGU strategy effects and non-EGU effects to make a selection between two different approaches. Rather, both the selected EGU and non-EGU emissions reduction strategies at the cost-effectiveness values identified in section V.B and V.C of this document present a comprehensive solution to eliminating significant contribution for the covered states. The combined effect of the EGU and non-EGU strategies is further presented in the following section.

TABLE V.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	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU
40278011	Arizona	Yuma	69.87	69.80	71.47	71.40
80590006	Colorado	Jefferson	71.70	71.34	72.30	71.93
80590011	Colorado	Jefferson	72.06	71.57	72.66	72.16
80690011	Colorado	Larimer	69.84	69.53	71.04	70.72
90013007	Connecticut	Fairfield	71.25	70.66	72.06	71.46
90019003	Connecticut	Fairfield	71.58	71.06	71.78	71.26
350130021	New Mexico	Dona Ana	70.06	69.86	71.36	71.16
350130022	New Mexico	Dona Ana	69.17	68.96	71.77	71.56
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.50	72.02	70.58
481671034	Texas	Galveston	71.29	69.28	72.51	70.47
482010024	Texas	Harris	74.83	73.39	76.45	74.98
490110004	Utah	Davis	69.90	69.28	72.10	71.46
490353006	Utah	Salt Lake	70.50	69.91	72.10	71.50
490353013	Utah	Salt Lake	71.91	71.40	72.31	71.80
551170006	Wisconsin	Sheboygan	70.83	70.27	71.73	71.17
Average AQ Change Relative to Base (ppb)						0.66
Total PPB Change Across All Receptors Relative to Base (ppb)						9.87

Table Notes:

[a] The EPA notes that the design values reflected in Table V.D.–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 Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in Table V.D.2–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling.

[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 VIII of this document provides a more complete picture of the air quality impacts of the final rule.

[250] Nonetheless, recognizing the diverse non-EGU industries and emissions units covered in this action and the potential that certain individual facilities and emissions units may face extreme hardship in meeting the general requirements being finalized in this action, the EPA has provided mechanisms in the regulatory requirements for industrial sources that provide for some flexibility in the emissions limits based on a demonstration of technical impossibility or extreme economic hardship. *See* section VI.C of this document.

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 Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

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 air quality effects of the rule and to conduct our over-control analysis. EPA's evaluation demonstrated air quality improvement at the remaining nonattainment or maintenance receptors outside of California (*see* section IV.D of this document for receptor details). The EPA estimated that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.66 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 non-EGU industries. Table V.D.3–1 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 are projected to deliver meaningful downwind air quality improvements.

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

Sector/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)	16,282	0.71	0.05
EGU SCR/SNCR Retrofit	55,672	6.34	0.42
Non-EGU Industries	44,616	2.82	0.19
Total	....	9.87	0.66

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 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 associated health and climate benefits are discussed in section VII of this document.

[b] The EPA notes that the design values reflected in Tables V.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 Final Rule TSD. Additionally, these emissions reduction values vary slightly from the technology reduction estimates described in section V.C of this document, as the values here reflect the sum of the final identified stringency for each state (*e.g.,* SCR retrofit potential is not assumed in Alabama, Minnesota, and Wisconsin).

[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 V.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 VIII of this document provides a picture of the projected air quality impacts of the final rule using modeling techniques that differ from the methodologies employed here.

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. The EPA performed air quality analysis using the Ozone AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is an identified, less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that 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) to all receptors. 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. Further, 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.*[251]

[251] Although the Court described over-control as going beyond what is needed to address ''nonattainment'' problems, the EPA interprets this

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 Transport Policy Analysis Final Rule TSD for details on the construction and application of AQAT).

Similar to our approach in the CSAPR Update and the Revised CSAPR Update, our primary overcontrol assessment examines the receptor changes from the emissions reductions of the upwind states found linked to a receptor. Consistent with prior Rules, EPA also assumed that downwind states that are not upwind states in this rule implement reductions commensurate with the rule's requirements (this treatment applies specifically to Colorado and Connecticut). This configuration effectively presents an equitable representation of the effects of the rule in that linked upwind states do not shift their responsibility to other upwind states linked to different receptors. It also effectively resolves any interdependence and ''which state goes first?'' questions. Furthermore, the downwind states in which a receptor is located are held to a ''fair share'' of emissions reductions—*i.e.,* the same level of emissions control stringency that the upwind states must implement.

The EPA also repeated this analysis using an alternative configuration, as described in the Ozone Transport Policy Analysis Final Rule TSD. In this configuration, we looked at the combined effect of the entire program across all linked upwind states on each receptor and did not assume that a downwind state that is not also an upwind state makes any additional emissions reductions beyond the baseline in the relevant year. This configuration effectively isolates how the rule as a whole, and just the rule, will affect air quality and linkages. While the first configuration described is, in the Agency's view, the more appropriate way to evaluate overcontrol, taken together the configurations provide a more robust basis on which to rest our conclusions regarding overcontrol. In any case, as further illustrated in the Ozone Transport Policy Analysis Final Rule TSD, our analysis under both configurations establishes that there is no overcontrol and so there is no need to reconcile any difference in results between them.

We also looked at the ordering of increments of emissions reduction and have found that it does not matter whether we assume EGU emissions controls would be applied first, followed by non-EGU controls, or vice-versa. For 2023, the question is moot as there are only EGU reductions to examine. For 2026, the analysis showed there would be no overcontrol either way. In 2026, the EPA's overcontrol analysis (as presented here) examined all EGU reductions first and layered in non-EGU reductions in the last step of the overcontrol check. However, the EPA also examined an alternative ordering scenario where the non-EGU reductions were assessed prior to the EGU reductions associated with installation of new SCR post-combustion controls (see the Ozone Transport Policy Analysis Final Rule TSD for details). This ordering did not impact the results of the overcontrol test. The specific results of these analyses are presented in the TSD.

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, is not estimated to change the status of any receptors.[252] Thus, the nonattainment or maintenance receptors that the states are linked to remain unresolved. Nor do any states' contribution levels drop below the 1 percent of NAAQS threshold. Thus, the EPA determined that none of the 23 linked states have all of their linkages resolved at the final EGU level of control stringency in 2023, and hence, the EPA finds no over-control in the final level of stringency.

Based on the air quality baseline modeling for 2026, all receptors to which Alabama, Minnesota, and Wisconsin are linked in 2023 are projected to be in attainment in 2026. Therefore, no additional stringency is finalized for EGUs or non-EGUs in those states beyond the 2023 level of stringency. For the remaining 20 states, the selected control stringency beginning in 2026 includes additional EGU controls and the non-EGU emissions reductions.

The EPA assesses air quality impacts and overcontrol in the year 2026 in this final rule, even though the rule accommodates the potential need for individual facilities (both EGU and non-EGU) to have some additional time to come into compliance. The EPA views this additional time to be a reflection of need (based on demonstrated impossibility) that is justified at Step 4 of the interstate transport framework rather than at Step 3. As explained in section VI.A of this document, with respect to EGUs, the EPA extends the full implementation of the SCR retrofit-based reductions across 2026 and 2027 to accommodate any *unit-level* scheduling challenges. However, we find that many sources can meet a three-year installation time and the trading program features and the allowance price will incentivize these reductions to occur as soon as possible. Similarly, with respect to non-EGU industrial sources, the final rule provides limited circumstances for individual facilities to seek and to be granted extensions of time to install required pollution controls and achieve the emissions rates established in this rule based on a showing of necessity. Those circumstances where an extension may be warranted for any specific facility are unknown at this time and will be evaluated through a source-specific application process, where the need for extension can be established with source-specific evidence. See section VI.C of this document. Further, 2026 is the critical analytic year associated with the last full ozone season before the 2027 Serious area attainment date and is the year by which significant contribution must be eliminated if at all possible. Therefore, for purposes of this analysis, the collective *state and regional* representation of these reductions are fully assumed in 2026. The potential ability of both EGU and non-EGU sources to have some amount of additional time beyond 2026 to comply with requirements that we have determined at Step 3 are necessary to eliminate significant contribution does not necessitate evaluating a later year than 2026 for overcontrol. The stringency of the control program does not alter in any year beyond 2026.[253] By

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.

[252] For purposes of this rule, the violating monitor receptors inform our determinations at Step 1 and 2 by strengthening the analytical basis on which we conclude upwind states are linked in 2023. Because no linkages identified using our air quality modeling methodology resolve in 2023 under the selected control stringency, it is not necessary to evaluate overcontrol with respect to the additional set of violating-monitor receptors.

[253] Thus, we note, this circumstance is different than the record on which overcontrol was found in *EME Homer City.* There, CSAPR would have implemented an increase in the emissions control stringency of the rule (as reflected in a change in emissions control stringency expressed as dollars

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fully reflecting all Step 3 emissions reductions in its overcontrol test for 2026, EPA ensures that it is not understating the emissions impact and benefit when performing the test.

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 is estimated to change the status of three receptors to attainment or maintenance in 2026. Brazoria County, Texas (Monitor ID 480391004); and Galveston County, Texas (Monitor ID 481671034), are estimated to come into attainment. We observe that one of the Fairfield, Connecticut, receptors (Monitor ID 090013007) is estimated to go from nonattainment to maintenance (when EGU emissions reductions with SCR are applied, prior to the application of the non-EGU emissions reductions). This receptor is expected to remain in maintenance even after the application of the non-EGU emissions reductions. Based on these data, EPA finds that all linked states except Arkansas, Mississippi, and Oklahoma are projected to 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 states. Arkansas, Mississippi, and Oklahoma are linked to at least one of the two Texas receptors that are projected to come into attainment with the full implementation of the control strategy at Step 3. However, these two Texas receptors are expected to remain as maintenance-only receptors prior to the final increment of reductions assessed (the addition of the non-EGU reductions), so EPA concludes that imposition of the incremental non-EGU level is appropriate to avoid under-control as to these states and does not constitute overcontrol.[254]

Next, the EPA evaluated the potential for over-control with respect to the 1 percent of the NAAQS threshold applied in this final 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 23 linked states in 2023 or 20 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 are projected to continue 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. EPA notes that in 2026, for Oklahoma, when the incremental level of stringency associated with the non-EGU control strategy is applied, Oklahoma's contribution to Galveston County Texas is expected to drop below the 1 percent threshold (at the same time that the receptor has its maintenance problems resolved). EPA concludes that this does not constitute overcontrol because both the receptor and the contribution are estimated to remain above the maintenance level and linkage threshold at the prior level of stringency and, thus, since otherwise justified at Step 3, the full stringency for 2026 is appropriate to avoid under-control. For more information about this assessment, refer to the Ozone Transport Policy Analysis Final Rule TSD and the Ozone AQAT.

Therefore, EPA finds that all of the selected EGU and non-EGU NO_X reduction strategies selected in EPA's Step 3 analysis can be applied to all states linked in 2026 to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS without introducing an overcontrol problem based on the present record. 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.

The determination that the stringency of this action does not constitute overcontrol for any linked state is further reinforced by EPA's observation in section III.A of this document regarding the nature of the ozone problem. Ozone levels are known to vary, at times dramatically, from year to year. Future ozone concentrations and the formation of ground level ozone may also be impacted by factors in future years that the EPA cannot fully account for at present. For example, changes to meteorological conditions could affect future ozone levels. Climate change could also contribute to higher than anticipated ozone levels in future years through wildfires and heat waves, which can contribute directly and indirectly to higher levels of ozone. Any modeling projection can be characterized as having some uncertainty, and that is not a sufficient reason to ignore modeling results. However, in the context of the overcontrol test, the question is whether it is clear according to particularized evidence that there is no need for the emissions reductions in question. *See EME Homer City,* 572 U.S. at 523 (''[A] degree of imprecision is inevitable in tackling the problem of interstate air pollution. Slight changes in wind patterns or energy consumption, for example, may vary downwind air quality in ways EPA might not have anticipated.''). Under this standard, the degree of attainment that is projected to occur under the rule in relation to the Texas receptors discussed above is not so large or certain to occur that it would be appropriate to attempt to devise a less stringent emissions control strategy for the relevant linked states as a result, particularly in light of the fact that at the penultimate stringency level the receptors are not resolved.

It is also possible that ozone-precursor emissions from certain sources may decline beyond what we currently project in this rule. For example, the IRA may result in reductions in fossil-fuel fired generation, which should in turn result in lower NO_X emissions during the ozone season.[255] We have

per ton from $100/ton to $500/ton). That change in stringency marked a determination that EPA had made at Step 3 regarding the degree of emissions reduction that sources needed to achieve beginning in 2014. But in that year, the court found EPA's record to reveal that certain states would not need to go up to that higher level of stringency because air quality problems and/or linkages were already projected to be resolved at the lower level of stringency. *See* 795 F.3d at 128–30. The analogous year to 2014 here is 2026. The stringency level of this control program does not change post-2026. Nor do we think individual sources should gain the benefit of delaying emissions reductions simply in the hopes that they could show those reductions would be overcontrol; each source must be held to the elimination of its portion of significant contribution. Necessity may demand some additional amount of time for compliance, but equity demands that individual sources not gain an untoward advantage from delay and reliance on other sources' timelier compliance.

[254] Even with full implementation of the rule, these two receptors are only projected to come into attainment by a relatively small degree, and no policy option is ascertained in the record by which attainment could be achieved to an even lesser degree. Nonetheless, the EPA further evaluated whether there were any overcontrol concerns through sensitivity analyses. Under all scenarios, the EPA finds there is no overcontrol. See the Ozone Transport Policy Analysis Final Rule TSD for more discussion and analysis.

[255] As discussed in section IV.C.2.b, there are also potential ways in which the IRA may not necessarily result in reductions in NO_X emissions from EGUs.

assessed this scenario to ensure our overcontrol conclusions are robust even if the IRA has those effects. As discussed in the Regulatory Impact Analysis, the EPA conducted additional modeling of the final policy scenario (inclusive of economically efficient methods of compliance available within the Step 4 implementation programs) using its IPM tool. The EPA observes that the differences in estimated costs and emissions reductions in the IRA sensitivity (presented in Appendix 4A of the RIA) suggests that there would also be differences in estimated health and climate benefits under that scenario, although the Agency did not have time under this rulemaking schedule to quantify those differences. The EPA also used AQAT to conduct an additional EGU modeling sensitivity reflecting the IRA. Both the IPM sensitivity and the corresponding AQAT assessment of the IRA scenarios demonstrated no overcontrol as every state linkage to a downwind problematic receptor persisted in the penultimate level of stringency when EPA performed its Step 3 evaluation—even when the impacts of the IRA are incorporated. This further affirmed EPA's conclusion of no overcontrol concerns at the stringency level of the final rule. This overcontrol sensitivity is further discussed in the Ozone Transport Policy Analysis Final Rule TSD, Appendix K.

In light of the mandate of the CAA to protect the public health and environment through the elimination of significant contribution under the Good Neighbor Provision for the 2015 ozone NAAQS, nothing in the present record establishes on an as-applied, particularized basis that this rule will result in an unnecessary degree of control of upwind-state emissions.

Comment: Many commenters alleged that the rule overcontrols emissions by more than necessary to eliminate significant contribution for the 2015 ozone NAAQS, on the basis that the emissions reductions are unnecessary or are unnecessarily stringent.

Response: As discussed earlier in this section, EPA has analyzed whether this rule ''overcontrols'' emissions and has found based on a robust, multi-faceted analysis, that it does not. In particular, EPA has not identified a lesser-stringency emissions control strategy for any state that would either fully resolve the air quality problems at a downwind receptor location or resolve that upwind state's linkage to a level below the 1 percent of NAAQS contribution threshold. No commenter has provided a particularized, as-applied analysis demonstrating that EPA's emissions control strategy will actually result in any overcontrol of emissions in the manner the EPA or courts have understood that term, and overcontrol allegations must be proven through particularized, as-applied challenges. *See EME Homer City,* 795 F.3d at 127; *see also Wisconsin,* 938 F.3d at 325 (''[T]he way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a 'particularized, as-applied challenge.' '' Accordingly, as we did when presented with similar arguments in *EME Homer III,* we reject Industry Petitioners' arguments because they do no more than speculate that aspects of 'EPA's methodology *could* lead to over-control of upwind States.' '') (cleaned up) (citing *EME Homer City,* 795 F.3d at 136–137).

Comment: For 2 of the 20 states linked in 2026, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.,* Brazoria County, Texas) was estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions at proposal. Commenters noted that this suggested application of the estimated non-EGU, and/or some EGU, emissions reductions constituted over-control for these states.

Response: EPA notes that at proposal, this downwind receptor only resolved by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions. As explained earlier in this section, the final rule air quality modeling shows that the receptors to which these states are linked do not resolve upon full implementation of the identified EGU reductions by themselves, and only reach attainment by a small degree following the additional reductions from the non-EGU control strategy.[256] If the EPA were to select the control stringency of this penultimate step, both upwind-state contribution and downwind-state air quality receptors would persist while the cost-effective emissions reductions that were identified to eliminate significant contribution remain available but un-implemented. This would constitute under-control. Consequently, as described, the EPA views the control stringency required of these states in this final rule as not constituting over-control and appropriate to eliminate significant contribution to nonattainment and interference with maintenance of this NAAQS in line with our Step 3 determinations for all other states. See the Ozone Transport Policy Analysis Final Rule TSD section C.3 for discussion and analysis regarding overcontrol for states solely linked to one or both of these receptors.

Comment: Commenters raised a variety of arguments that the enhancements to the EGU trading program in this action will result in overcontrol of power plant emissions. They alleged that dynamic budgeting would cause the budget to continually decrease even after significant contribution is eliminated. They similarly argue that annual emissions bank recalibration and the emissions backstop emissions rate have not been shown to be justified to eliminate significant contribution.

Response: This final rule's determination regarding the appropriate level of control stringency for EGUs finds that the amounts of NO_X emissions reduction achieved through these strategies at EGUs are appropriate and cost-justified under the Step 3 multifactor analysis. These determinations are associated with particular emissions control technologies and strategies as detailed in sections V.B.1 and V.C.1 above. It is the implementation of those strategies at the covered EGU sources and the air quality effects of those strategies (coupled with non-EGUs) in the relevant analytic year of 2026 on which we base our determination of significant contribution at Step 3. This includes the evaluation of whether there is overcontrol, which is also conducted for the 2026 analytic year as explained above. As explained below, we disagree that the enhancements to the trading program at Step 4 implicate the need for further overcontrol analysis. These enhancements operate together to ensure the trading program continues to maintain the Step 3 emissions control stringency over time. These enhancements reflect lessons learned through EPA's experience with prior trading programs implemented under the good neighbor provision. None of commenters' arguments that these enhancements result in overcontrol are persuasive.

Commenters contend that these enhancements to the trading program go

[256] Because in the final record we do not identify cost, air quality, and emission reduction factors that sufficiently differentiate either source-type or emissions control strategy among the Tier 1 and Tier 2 industries identified at proposal, we combined the non-EGU industries and emissions reductions into one group, and we are finalizing requirements for all non-EGU industries and most emissions unit types identified at proposal. In light of the small degree to which the relevant receptors reach attainment and the multi-faceted assessment of overcontrol we have undertaken, the overcontrol assessment with respect to non-EGUs in the final rule is sufficient to establish that there is no overcontrol.

beyond a mass-based budget approach as applied in CSAPR. Because these improvements in the program result in a continuing incentive for each covered EGU source to maintain the pollution control performance the EPA found appropriate to eliminate significant contribution at Step 3, commenters believe these enhancements must necessarily result in prohibited overcontrol. These arguments appear to be premised on the assumption that overall emissions may later decline to such a point that there is no longer a linkage between a particular state and any downwind receptors for reasons other than the requirements of this rule.

As an initial matter, no commenter has provided an empirical analysis demonstrating that the control stringency identified at Step 3 to eliminate significant contribution would actually result in any overcontrol. The case law is clear that over-control allegations must be proven through particularized, as-applied challenges. See prior response to comments. More importantly here, the Group 3 trading program enhancements do not impose increased stringency in years after 2030 and do not force emissions to continually be reduced to ever lower levels. They are only designed to incentivize the implementation of the Step 3 emissions control stringency that eliminates significant contribution. The circumstances that could potentially cause a receptor or linkage to resolve at some point in the future after 2026 are not circumstances that are within the power of this rule to control. Nor would those circumstances present a justification as to why upwind sources should no longer be obligated to eliminate their own significant contribution. *Wisconsin,* 938 F.3d at 324–25 (rejecting overcontrol arguments premised on attributing air quality problems to other emissions).

Further, the EPA is not constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA has defined the ''amount'' of emissions that must be prohibited to eliminate significant contribution in this action based on a series of determinations of which emissions control strategies, for certain identified EGU and non-EGU sources, are appropriate applying the Step 3 multifactor analysis. Notably, the non-EGU industrial source emissions reductions in this action are *not* being achieved at Step 4 through mass-based emissions trading, nor are they required to be by any provision of the CAA. See section III.B.1.

As explained in sections III.B.1.d and VI.B.1 of this document, the EPA finds good reason based on its experience with trading programs that using fixed, mass-based, ozone-season wide budgets does not necessarily ensure the elimination of significant contribution over the entire region of linked states or throughout each ozone season. Even in the original CSAPR rulemaking, which promulgated only fixed, mass-based budgets, such outcomes were never the EPA's intention to allow. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the experience of the Agency since that time establishes a real risk of ''under-control'' if the existing trading framework is not enhanced. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

Further, the EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR 23121–22. The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that a mass-based emissions-trading framework incentivizes continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions limitations, which under the Act would typically apply in perpetuity and may only be modified through a future SIP- or FIP-revision rulemaking process. *See* CAA section 110(i) prohibiting modifications to implementation plan requirements except by enumerated processes. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96.

Further, these enhancements are directly related to assisting downwind areas specifically with the goal of attaining and maintaining the 2015 8-hour ozone NAAQS. In this respect, they are not ''unnecessary'' or ''unrelated'' to carrying out the mandates of CAA section 110(a)(2)(D)(i)(I). Taking measures to ensure that each upwind source covered by an emissions trading program is adequately incentivized to eliminate excessive emissions (as found at Step 3) throughout the entirety of each ozone season is entirely appropriate in light of the nature of the ozone problem. Ozone exceedances recur on varying days throughout the summertime ozone season, and it is not possible to predict in advance which specific days will have high ozone. Further, impacts to public health and the environment from ozone can occur through short-term exposure (*e.g.,* over a course of hours, *i.e.,* on a daily basis). The 2015 ozone NAAQS is expressed as an 8-hour average, and only a small number of days in excess of the ozone NAAQS can cause a downwind area to be in nonattainment. Thus, even a small number of exceedances can result in continuing and/or increased regulatory burdens on the downwind jurisdiction. Taking these considerations into account, it is evident that a fixed, mass-based emissions program that does not adequately incentivize emissions reductions commensurate with our Step 3 determinations on each day of every ozone season going forward does not provide a sufficient guarantee that the emissions that significantly contribute on those particular days and at particular receptor locations when ozone levels are at risk of exceeding the NAAQS have been eliminated. *See* section V.B.1.a and VI.B of this document for more discussion of data observations regarding SCR optimization.

These enhancements are also consistent with the general policies and principles EPA has long applied in implementing the NAAQS through the SIP/FIP framework of section 110. Emissions control measures relied on to meet CAA requirements must be permanent and enforceable and included in the implementation plan itself. *See, e.g., Montana Sulfur & Chem. Co.* v. *EPA,* 666 F.3d 1174, 1196 (9th Cir. 2012); 40 CFR 51.112(a). In the General Preamble laying out EPA's plans for implementing the 1990 CAA Amendments, the EPA identified a core ''principle'' that control strategies should be ''accountable.'' ''This means, for example, that source-specific limits should be permanent and must reflect the assumptions used in the SIP demonstrations.'' 57 FR 13498, 13568 (April 16, 1992). EPA went on, ''The principles of quantification, enforceability, replicability, and accountability apply to all SIPs and control strategies, including those involving emissions trading, marketable permits and allowances.'' *Id.* EPA also explained that its ''emissions trading policy provides that only trades producing reductions that are surplus, enforceable, permanent, and quantifiable can get credit and be banked or used in an emissions trade.'' *Id.* These principles follow from the language of the Act, including CAA section 110(a)(2), 107(d)(3)(E)(iii), 110(i), and 110(l). These provisions and principles further underscore the importance of ensuring that the emissions reductions the EPA has found necessary to eliminate significant contribution are in fact implemented on a consistent and permanent basis even within the context of an emissions trading program.

The EPA disagrees that the budget adjustments that would occur over time under this final rule (for example, the annual dynamic-budget adjustment) must be reassessed each time they occur through notice and comment rulemaking under CAA section 307(d). This would serve no purpose. The formulas that the EPA will apply to adjust the budgets and allowance bank are set in this final rule and are intended to maintain, not increase (or decrease), program stringency. While the EPA intends to provide an opportunity for stakeholders to review and propose corrections to its data as it implements the established budget formulas, no larger reassessment of the emissions control program is needed on an ongoing basis, because, again, that program is simply calibrated to ensure that emissions reductions commensurate with the determination of ''significance'' in Step 3 continue to be obtained over the long term. As described earlier, these trading program provisions are analogous to, or mimic, the effect of unit-specific emissions limitations that apply in perpetuity.[257]

Commenters also confuse the ''amount'' of emissions that must be eliminated under CAA section 110(a)(2)(D)(i)(I) as being synonymous with a fixed, mass-based budget that reflects the residual emissions allowed following the elimination of significant contribution. However, EPA views the ''amount'' to be eliminated as those emissions that are in excess of the cost-effective emissions control strategies identified in Step 3. This is further explained in section III.B.1 of this document.

Thus, this rule is in compliance with the overcontrol principles that the D.C. Circuit applied on remand in *EME Homer City* to find certain instances of overcontrol in CSAPR's emissions control strategies. The D.C. Circuit found that EPA had imposed more stringent emissions-control strategies for certain states than were necessary to resolve all of those states' linkages. 795 F.3d at 128–30. Specifically, for sulfur dioxide, the court found certain receptors would reach attainment if all linked upwind states had implemented ''cost controls'' at $100/ton or $400/ton, rather than EPA's selected stringency level of $500/ton. Similarly, for ozone season NO_X, the court found that receptors were projected to attain the NAAQS at stringencies below $500/ton. The court's focus was on the *stringency* of the emissions control obligations as determined through the application of cost thresholds at Step 3 of the analysis. The court did not hold that EPA may only use fixed, mass-based budgets to implement those reductions. The court did not hold that EPA must permit individual polluting sources to be allowed to increase their emissions at some point in the future. The court did not hold that EPA's good neighbor FIPs must, effectively, contain termination clauses, such that they cease to ensure the implementation of the control stringency determined as necessary at Step 3, the moment a downwind receptor reaches attainment. Indeed, such a rule would contravene the statute's clear, forward-looking directive that EPA must also eliminate upwind emissions that interfere with *maintenance* of the NAAQS; *see North Carolina,* 531 F.3d at 908–911; *Wisconsin,* 938 F.3d at 325–26.

The *EME Homer City* court on remand in fact rejected various arguments that other aspects of EPA's emissions control strategy in CSAPR resulted in overcontrol, holding that EPA had properly given effect to the interfere with maintenance prong, and noting that petitioners failed to make out proven, as-applied demonstrations of overcontrol:

> At bottom, each of those claims is an argument that EPA's methodology could lead to over-control of upwind States that are found to interfere with maintenance at a downwind location. That could prove to be correct in certain locations. But the Supreme Court made clear in *EME Homer* that the way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a ''particularized, as-applied challenge.'' *EME Homer,* 134 S. Ct. at 1609, slip op. at 31. And petitioners do not point to any actual such instances of over-control at downwind locations.

795 F.3d at 137. The court went on to observe, ''EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.' If States have been forced to reduce emissions beyond that point, affected parties will have meritorious as-applied challenges.'' *Id.* (quoting 572 U.S. at 521–22). But this too was not a holding that EPA may not ensure effective and permanent implementation of an emissions control stringency that EPA has found warranted under CAA section 110(a)(2)(D)(i)(I). Such an approach is available through the more conventional CAA practice of setting unit-specific emissions limitations that would apply on a permanent and enforceable basis. *See* CAA sections 110(a)(2) and 302(y) (providing for SIPs and FIPs to include ''enforceable emissions limitations'' in addition to economic incentive measures like trading programs).[258] This is in fact how EPA intends to ensure significant contribution is eliminated from non-EGU industrial sources for which a mass-based trading regime is, at least at the present time, unworkable (see section VI.C of this document). And EPA has provided for the elimination of significant contribution through source-specific emissions limitations in prior transport actions as well, so this position is not novel. See section III.B of this document.

Nonetheless, EPA recognizes that under the Act, both FIPs and SIPs may be revised, and states may replace FIPs with SIPs if EPA approves them. Any such revision must be evaluated to ensure no applicable CAA requirements are interfered with. *See, e.g., Indiana* v. *EPA,* 796 F.3d 803 (7th Cir. 2015). For example, states may be able to demonstrate in the future that through some other permanent and enforceable methods of emissions reduction that they have adopted into their SIP, they will be able to achieve a similar emissions control stringency with different emissions reduction requirements imposed on different sources as compared to the FIPs finalized in this action. See section VI.D of this document.

Therefore, commenters' contentions that EPA's trading program enhancements result in prohibited

[257] We note further that because all of the trading program provisions, including the dynamic budget-setting provisions and process, are established by this final FIP rulemaking, the ministerial future-year budget adjustment process complies with the CAA section 110(i) prohibition on modification of implementation plan requirements except by enumerated process.

[258] ''Emissions limitation'' is in turn defined at CAA section 302(k) as a ''requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis. . . .''

overcontrol are not proven through as-applied, particularized challenges, and they are premised on an incorrect understanding of the CAA and the relevant case law. The Agency rejects the contention that it must somehow provide in the present FIP action for a relaxation in the stringency of the Step 4 implementation program and thus allow for the recurrence of pollution that we have found here, in this action, significantly contributes to downwind ozone nonattainment and maintenance problems.

VI. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This action will ensure that emissions reductions necessary to eliminate significant contribution will be achieved ''as expeditiously as practicable'' and no later than the downwind attainment dates except where compliance by those dates is not possible. *See* CAA section 181(a); *Wisconsin,* 938 F.3d at 318–20. The timing of this action will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season for the covered states, 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 will take effect as expeditiously as practicable. Emissions reductions commensurate with SCR mitigation measures for EGUs will start in 2026 and be fully implemented by 2027. Emissions reductions through the mitigation measures for industrial sources will generally go into effect in 2026; however, as explained in section VI.C of this document, we have provided for case-by-case extensions of up to one year based on a demonstration of necessity (with the potential for up to an additional two years based on a further demonstration). The full suite of emissions reductions is generally anticipated to take effect by the 2027 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This rule constitutes a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered; the EPA does not anticipate further rulemaking to address good neighbor obligations under this NAAQS will be required for these states with the finalization of this rule.

EPA's determinations regarding the timing of this rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times 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.[259] 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 $PM_{2.5}$.[260] 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.[261] 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.[262] 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.''[263]

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

The near-term EGU control stringencies and corresponding reductions in this rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the portion of full remedy reductions related to post combustion control installation identified in sections V.B through V.D of this document 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 V.B through V.D of this document 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. 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 VI.B.7 of this document, unit-specific backstop daily emissions rates are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions through state emissions budgets starting in 2023 while imposing the unit-specific backstop emissions rates in 2024 achieves the necessary environmental

[259] *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).

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

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

[262] *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*).

[263] *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).

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 22 states for which emissions reduction requirements for EGUs are established under this 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).[264] The EPA is applying the same timing assumption regarding combustion control upgrades for this rulemaking. Given the same relationship here between the date of final action and the year one ozone season, the EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until year two (*i.e.,* the 2024 ozone season). Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for all covered states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade is included and reflected in those state budgets beginning in 2024—which means EGUs in those states have even more time than the 14 months between finalization of this rule and the 2024 ozone season if they started any planning or installation earlier in response to the Revised CSAPR Update.

2. 2026 and Later Years: EGU and Stationary Industrial Source NO_X Reductions Beginning in 2026

The EPA finds that it is not possible to implement all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date. In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is aligning 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. The 2026 ozone season is the last full ozone season that precedes the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[265] The EPA proposed to require compliance with all of the remaining EGU and non-EGU control requirements beginning in the 2026 ozone season. The EPA continues to find 2026 to be the relevant analytic year for purposes of its Step 3 analysis, including its analysis of overcontrol, as discussed in section V.D.4 of this document. However, many commenters argued that full implementation of the EGU and industrial source control strategies is not feasible for every source by the 2026 ozone season. The EPA addresses these technical comments specifically in sections V.B and VI.C of this document. The EPA also commissioned a study to develop a better understanding of the time needed for installation of emissions controls for the industrial sector units covered in this rule, which is included in the docket and discussed in section VI.A.2.b of this document. While the EPA does not agree with all of the commenters' assertions regarding the time they claim is needed for control installation, in other respects the concerns raised were sufficient to justify some adjustments to the compliance schedule for the final rule. We have provided for the emissions reductions commensurate with assumed EGU post-combustion emissions control retrofits to be phased in over the 2026 and 2027 ozone season emissions budgets, and we have provided a process in the final regulations for individual non-EGU industrial sources to seek limited compliance extensions extending no later than 2029 based on a case-by-case demonstration of necessity. This compliance schedule delivers substantial emissions reductions in the 2026 and 2027 ozone seasons and before the 2027 Serious area attainment date, and it only allows compliance extensions beyond that attainment date based on a rigorous, source-specific demonstration of need for the additional time.[266]

The timing of this final rule provides three to four years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the start of the 2026 and 2027 ozone seasons. In addition, the publication of the proposal provided roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning (steps that can be taken prior to any capital investment) 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 reasonable and achievable. A 3-year period for installation of 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 three 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.[267] Thus, in the provision that allows for direct Federal regulation of sources violating the good neighbor provision, Congress established three years as the maximum amount of time available from a final rule to when emissions reductions need to be achieved at the relevant source or group of sources. Because this action is not taken under CAA section 126(c), the mandatory timeframe for implementation of emissions controls

[264] 86 FR 23093.

[265] 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).

[266] While we generally use the term ''necessity'' to describe the showing that non-EGU facilities must meet in seeking compliance extensions, the elements for this showing are designed to allow the EPA to make a judgment that comports with the standard of ''impossibility'' established in case law such as *Wisconsin.* In other words, the ''necessity'' for additional time is effectively a showing by the source that it would be ''impossible'' for it to meet the compliance deadline.

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

under that provision is not directly applicable, but it is informative.

In response to arguments from sources that more time than has been provided in the final rule is necessary, this provision strongly indicates that allowing time beyond a three-year period must be based on a substantial showing of impossibility. Our analysis based on comments and considering additional information is that the additional time we have provided in the final rule is both justified and sufficient in light of the statutory objective of expeditious compliance.

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.[268] 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 three years after the deadline for submitting RACT SIP revisions.[269] 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.[270] 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.[271] Nonattainment areas for the 2015 ozone NAAQS that were reclassified to Moderate nonattainment in October 2022 face this same regulatory schedule, meaning that their sources are required to implement RACT controls in 2023. With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899 (Oct. 7, 2022). Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* In the October 2022 final rulemaking EPA made determinations that certain Marginal areas failed to attain by the attainment date, reclassified those areas to Moderate, and established SIP submission deadlines and RACM and RACT implementation deadlines. EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. *See* 87 FR 60897, 60900. The implementation deadline for RACM and RACT is also January 1, 2023. *Id.*

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA includes in this rule, as well as the types of emissions control technologies on which the EPA bases the emissions limitations that would take effect for the 2026 and 2027 ozone seasons, generally are 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.[272] 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 three years is an outer limit on the time that should be given sources to come into compliance where possible. In light of the January 1, 2023, deadline for implementation of RACT in Moderate nonattainment areas, the EPA finds that a May 1, 2026 deadline for full implementation of the emissions control requirements in this final rule would generally provide adequate time for any individual source to install the necessary controls, barring the circumstances of necessity discussed further in this section.

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. CAA section 112(i)(3)(B) 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 (7) provide for limited compliance extensions where other conditions are met.[273] 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 where possible. As discussed further in section VI.A.2.b of this document, the process for obtaining a compliance extension for industrial sources in this rule is generally modeled on 40 CFR 63.6(i)(3), which implements

[268] *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 SIP submission deadline under 40 CFR 51.1112(a)(2)) and 51.1312(a)(2)(i), respectively).

[269] 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 40 CFR 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.

[270] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

[271] *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.

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

[273] *See, e.g.,* CAA section 112(i)(4), which provides for limited compliance extensions granted by the President based on national security interests.

the extension provision for existing sources under CAA section 112(i)(3)(B).

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 an upper bound of time allowable (barring instances of impossibility) for existing stationary sources to install or begin the installation of 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,[274] the implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to 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 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 V.B.1.b of this document beginning in the 2026 ozone season (with full implementation by the 2027 ozone season for EGUs, and the availability of source-specific extensions based on a demonstration of necessity for non-EGUs).

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 under CAA section 110(c) to promulgate a FIP.[275] 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.''[276]

For the reasons provided in the following sub-sections, the EPA finds 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),[277] and, for certain sources, may not be possible by the 2026 ozone season or even the August 3, 2027, Serious area attainment date. While the EPA's technical analysis demonstrates that for any individual source, control installation could be accomplished by the start of the 2026 ozone season, in light of the scope of this rule coupled with current information on the present economic capacity of sources, control-installation vendors, and associated markets for labor and material, it is the EPA's judgment that a three-year timeframe is not possible for all sources subject to this rule collectively to come into compliance. Therefore, additional time beyond 2026 will be allowed for certain facilities in recognition of these constraints on the processes needed for installation of controls across all of the covered sources.

a. EGU Schedule for 2026 and Later Years

As discussed in sections V.B through V.D of this document, 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 36–48 months in this final rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA finds that these emissions reductions are not available any earlier than the 2026 compliance period. Starting in 2026, state emissions budgets will reflect full implementation of assumed SNCR mitigation measures and implementation of half the emissions reduction potential identified for assumed SCR mitigation measures. For each year in 2027 and beyond, state emissions budgets include all of the emissions 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[278]), nearly 19 GW of SCR 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 within a 36-month period.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of assumed SCR installation would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that many of the remaining coal units lacking SCR pose more site-specific installation challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA is making several changes in this final rule to address these concerns. First, EPA is phasing in emissions reductions commensurate with assumed SCR installations consistent with a 36-to-48-month time frame in this final rule, instead of a 36-month time frame as proposed. EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states. This phase-in approach to implementing SCR retrofit reduction potential over a three to four year period is in response to comments, including those from third-party full-service engineering firms. These commenters highlighted that while the

[274] 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).

[275] 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.

[276] *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'').

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

[278] *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.

proposed 36-month time frame is viable at the plant level, it would be ''very unlikely'' that the collective volume of SCR capacity could be installed in a three-year time frame based on a variety of factors. First, the commenters identified constraints on labor needed to retrofit 32 GW of capacity, highlighting that the Bureau of Labor and Statistics projects that there will be a decline in boilermaker employment over the decade and that the Associated Builders and Contractors (ABC) identifies the need for 650,000 additional skilled craft professionals on top of the normal hiring pace to meet the economy-wide demand created by infrastructure investment and other clean energy projects (*e.g.,* carbon capture and storage). They highlighted the decline in companies serving this type of large-scale retrofit project as the lack of new coal units and the retirement of coal units has curtailed activity in this area over the past five years. They also identified supply bottlenecks for key SCR components that would slow the ability to implement a large volume of SCR within 3 years, affecting electrical conduits, transformers, piping, structural and plate steel, and wire (with temporary price increases ranging from 30 percent to 200 percent). Finally, commenters note that site-specific conditions can make retrofits for individual units a lengthier process than historical averages (*e.g.,* under prior rules more accommodating sites retrofitted first) and that four years may be necessary for some projects, accordingly. EPA found the technical justification submitted in comment consistent with its prior assessments that a range of 39–48 months is appropriate for SCR-retrofit timing within regional-scale programs.[279] Therefore, EPA is adjusting the timeframe to still incentivize these reductions by the attainment date while accommodating the potential for some SCR retrofits to require between 36–48 months for installation.

Some commenters requested more than 48 months for SCR installation based on past projects that took five or more years. EPA disagrees with these commenters for two reasons. First, while EPA is identifying SCR retrofit potential to define significant contribution at Step 3, the rule only requires emissions reductions commensurate with that technology, implemented through a trading program, meaning that operators of EGUs eligible for SCR retrofit may pursue a variety of strategies for reducing emissions. Such compliance flexibility will accommodate extreme or unique circumstances in which a desired SCR retrofit is not achieved by the 2027 ozone season, although EPA finds such a circumstance exceedingly unlikely. Second, the historical examples that exceeded 48 months do not necessarily demonstrate that such projects are impossible to execute in less than 48 months, but rather that they can extend beyond that timeframe if no requirements or incentives are in place for a faster installation. As the D.C. Circuit has recognized, historical data on the amount of time sources have taken to install pollution controls do not in themselves establish the minimum amount of time in which those controls could be installed if sources are subject to a legal mandate to do so. *See Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'').

[279] 86 FR 23102.

b. Non-EGU or Industrial Source Schedule for 2026 and Later Years

The EPA proposed to require that all emissions reductions associated with the requirements for non-EGU industrial sources go into effect by the start of the 2026 ozone season, but also requested comment on its control-installation timing estimates for non-EGUs and requested comment on the possibility of providing for limited compliance extensions based on a showing of necessity. *See* 87 FR 20104–05.

Comment: The EPA received numerous comments regarding the inability of various non-EGU industries to install controls to comply with the emissions limits by 2026. Specifically, commenters raised concerns regarding the ability to meet these deadlines due to the ongoing geopolitical instability triggered by the war in Ukraine, COVID–19 pandemic-driven disruptions, and supply chain delays and shortages. Commenters also claimed that the EPA's three-year installation timeframe for non-EGUs does not account for the time needed to obtain necessary permits. Commenters stated that even where controls are feasible for a source, some sources would need to shut down due to their inability to install controls by 2026 and requested that the EPA provide additional time for sources to come into compliance. Commenters from multiple non-EGU industries stated that the proposed applicability criteria will require controls to be installed on thousands of non-EGU emissions units. Because of the number of emissions units, commenters raised concerns with permitting delays and the unavailability of skilled labor and necessary components. Commenters suggested various timelines for control installation timing ranging from one additional year to seven years. Other commenters asserted that the data supported the conclusion that all non-EGU sources, or at least some non-EGU sources, could install controls by 2026 or earlier, and that EPA has a legal obligation to impose good neighbor requirements as expeditiously as practicable by such sources, including earlier than 2026 if possible.

Response: After reviewing the information received during the public comment period and the additional information presented in the Non-EGU Control Installation Timing Report, the EPA has concluded that the majority of non-EGUs can install and operate the required controls by the 2026 ozone season. For the non-EGU control requirements on which the EPA has based its Step 3 findings as described in section V of this document, the emissions limits will generally go into effect starting with the 2026 ozone season (except where an individual source qualifies for a limited extension of time to comply based on a specific demonstration of necessity, as described in this section). The EPA finds that meeting the emissions limitations of this final rule through installation of necessary controls by an ozone season before 2026 is not expected to be possible for the industrial sources covered by this final rule.

The EPA recognizes that labor shortages, supply shortages, or other circumstances beyond the control of source owner/operators may, in some cases, render compliance by 2026 impossible for a particular industrial source. Therefore, the final rule contains provisions allowing source owner/operators to request limited compliance extensions based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of a source may initially apply for an extension of up to one year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance no later than the 2027 ozone season. The EPA may grant an additional case-based extension of up to two additional years for full compliance, where specific criteria are met.

The EPA initiated a study to examine the time necessary to install the potential controls identified in the final rule's cost analysis for all of the non-EGU industries subject to the final rule, including SNCR, low NO_X burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/advanced selective noncatalytic reduction

(ASNCR). The resulting report, which we refer to as the ''Non-EGU Control Installation Timing Report,'' identified a range of estimated installation times with minimum estimated installation times ranging from 6–27 months without any supply chain delays and 6–40 months with potential supply chain delays depending on the industry.[280] The Non-EGU Control Installation Timing Report also identified maximum estimated installation times ranging from 12–28 months without any supply chain delays and 12–72 months with potential supply chain delays depending on the industry. As indicated in the Non-EGU Control Installation Timing Report, the installation of layered combustion and NSCR control technology, in particular, could take between 9 and 72 months depending on supply chain delays.[281] The report also indicated that permitting processes may take 6 to 12 months but noted that these processes typically can proceed concurrent with other steps of the installation process.[282]

We find that the potential time needed for permitting processes is generally unlikely to significantly affect installation timeframes of at least three years given that a source that has three or more years to comply is expected, in most cases, to have adequate time to apply for and secure the necessary permits during that time. Permitting processes may, however, impact shorter installation times ranging from 12–28 months. Given the 12–28 month estimate for minimum and maximum installation times without supply chain delays and permitting timeframes typically ranging from 6–12 months, the EPA finds that the controls for non-EGU sources needed to comply with this final rule are generally not expected to be installed significantly before the 2026 ozone season.

Generally, the Non-EGU Control Installation Timing Report indicated that all non-EGU unit types subject to the final rule could install controls within 28 months if there are no supply chain delays. Thus, the Non-EGU Control Installation Timing Report confirms that for any individual facility, meeting the emissions limitations of this final rule through installation of controls can be completed by the start of the 2026 ozone season. It is only when the number of units in the U.S. potentially affected by the rule is taken into account, coupled with broader considerations of economic capacity including current information on supply-chain delays, that the potential need for additional time beyond 2026 becomes a possibility. Under ideal economic conditions (*i.e.,* no supply-chain delays or other constraints), affected units are estimated to be capable to install both combustion and post-combustion controls before the 2026 ozone season. Many commenters, however, provided information on installation timing estimates based on current supply chain delays and labor constraints. These commenters generally stated that installation of the necessary controls for some units would take longer than three years if supply chain delays similar to those that have occurred over the past few years continue. The Non-EGU Control Installation Timing Report reflected this information, together with additional information gathered from pollution control vendors, to develop ranges of estimates of possible installation times given current (*i.e.,* 2022) labor market conditions and material supplies. The Non-EGU Control Installation Timing Report also discussed how the installation and optimization of post-combustion controls over a similar timeframe at both EGUs and non-EGUs subject to this final rule would, considered cumulatively, potentially affect the installation timing needs of the covered non-EGU sources.

Based on information provided by commenters and vendors, the Non-EGU Control Installation Timing Report indicated that if current supply chain delays continue, control installations could take as long as 61 months for most non-EGU industries and possibly as long as 64–112 months in difficult cases. Notably, however, the conclusions in the Non-EGU Control Installation Timing Report reflect three key assumptions that could result in the relatively lengthy timing estimates at the outer end of this range: (1) the current state of supply chain delays and disruptions would continue without any increase in labor supply, materials, or reduction in fabrication timing; (2) the labor and materials markets would not adjust in response to this rule in the timeframe needed to meet the increased demand for control installations; and (3) the Report was unable to account for some of the flexibilities built into the final rule that will allow owners and operators to install controls on the most cost-effective units with shorter installation times.

As presented in the Non-EGU Control Installation Timing Report, supply chain delays and disruptions have generally been lessening since they peaked in 2020 during the COVID–19 pandemic, and many economic indicators have showed some improvement towards pre-pandemic levels, including freight transportation, inventory to sales ratios, interstate miles traveled, U.S. goods imports, and supply chain indices.[283] If these economic indicators continue to improve and the availability of fabricators and materials continues to trend upward, the control timing estimates identified in the Non-EGU Control Installation Timing Report could prove to be overstated for some industries and control technologies. In addition, the Non-EGU Control Installation Timing Report did not account for the labor and supply market adjustments that would be anticipated to occur to meet increased demand for control technologies and related materials and labor over the next several years in response to the rule. *Cf. Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes [of elongated control installation times] show is that installation can drag on when companies are unconstrained by the ticking clock of the law.''). For example, some of the longer installation timeframes identified in the Non-EGU Control Installation Timing Report are based on assumed limits on the current availability of skilled labor needed to install combustion controls and post combustion controls. If the market adjusts in response to increasing demand for this type of skilled labor in the timeframe needed for compliance (*e.g.,* there is an increase in boilermaker and engine controls labor), the installation timing estimates in the Non-EGU Control Installation Timing Report again could be overstated.

The Non-EGU Control Installation Timing Report also did not account for flexibilities provided in this final rule that will enable owners and operators of certain affected units to identify the most cost-effective and efficient means for installing any necessary controls. For example, one concern highlighted by commenters was the amount of time necessary to install controls on engines that have been in operation for 50 or more years. The requirements that we are finalizing for engines in the Pipeline Transportation of Natural Gas industry include an exemption for emergency engines and provisions allowing source owner/operators to request the EPA approval of facility-wide emissions averaging plans, both of which enable owners and operators of affected units to take costs, installation timing needs,

[280] *See generally* SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023) (''Non-EGU Control Installation Timing Report'').

[281] *See* Non-EGU Control Installation Timing Report, Executive Summary (March 14, 2023).

[282] Id. at Section 5.6.

[283] Id. at Section 6.1.

and other considerations into account in deciding which engines to control.

In response to industry concern about the number and size of units captured by the proposed applicability criteria, the EPA has made several changes to the applicability criteria in the final rule to focus the control requirements on impactful non-EGU units. As explained further in section VI.C of this document, the EPA is establishing exemptions for low-use boilers and engines where it would not be cost-effective to require controls at this time. Finally, as discussed in section VI.C.3 of this document, the EPA is not finalizing the proposed requirements for most emissions unit types in the Iron and Steel Mills and Ferroalloy Manufacturing industry given the EPA does not currently have a sufficient technical basis for finalizing those proposed requirements. These changes reduce the number of non-EGU units that will actually need to install controls and should reduce the strain on the labor and supply chain and permitting processes. For example, for engines, the EPA estimates that the facility-wide emissions averaging provision would, in many cases, allow facilities to install controls on only one-third of their engines, on average (see section VI.C.1 of this document for further discussion).

Taking all of these considerations into account, the EPA finds that the outer range of timing estimates presented in the Non-EGU Control Installation Timing Report generally reflects a conservative set of installation timing estimates and that the factors described previously could result in installation timeframes that fall toward the shorter end of the ranges of time that factor in supply-chain delays or could obviate those supply-chain delay issues entirely.

Based on all of these considerations, the EPA has concluded that three years is generally an adequate amount of time for the non-EGU sources covered by this final rule to install the controls in the 20 states that remain linked in 2026. The EPA also recognizes, however, that some sources may not be able to install controls by the 2026 ozone season despite making good faith efforts to do so, due to the aforementioned supply chain delays or other circumstances entirely beyond the owner or operator's control. Therefore, the final FIPs require compliance with the emissions control requirements for non-EGUs by the beginning of the 2026 ozone season, with limited exceptions based on a showing of necessity for individual sources that meet specific criteria. Where an individual owner or operator submits a satisfactory demonstration that an extension of time to comply is necessary, due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by May 1, 2026, the EPA may determine that installation by 2026 is not possible and thereby grant an extension of up to one year for that source to fully implement the required controls. If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply by the extended compliance date due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by the extended compliance date, the owner or operator may request and the EPA may grant a second extension of up to two additional years for full compliance, where specific criteria are met. This application process is generally in accordance with the concept on which the Agency requested comment in the proposal, *see* 87 FR 20104–05, and is modeled on a similar process provided for industrial sources subject to CAA section 112 NESHAPs, found at 40 CFR 63.6(i)(3).

The EPA intends to grant a request for an initial compliance extension only where a source demonstrates that it has taken all steps possible to install the necessary controls by the applicable compliance date and still cannot comply by the 2026 ozone season, due to circumstances entirely beyond its control. Any request for a compliance extension must be received by the EPA at least 180 days before the May 1, 2026, compliance date. The request must include all information obtained from control technology vendors demonstrating that the necessary controls cannot be installed by the applicable compliance date, any permit(s) secured for the installation of controls or information from the permitting authority on the timeline for issuance of such permit(s) if the source has not yet obtained the required permit(s); and any contracts entered into by the source for the installation of the control technology or an explanation as to why no contract is necessary. The EPA may also consider documentation of a source owner's/operator's plans to shut down a source by the 2027 ozone season in determining whether a source is eligible for a compliance extension. The owner or operator of an affected unit remains subject to the May 1, 2026 compliance date unless and until the Administrator grants a compliance extension.

The EPA intends to grant a request for a second compliance extension beyond 2027 only where a source owner/operator submits updated documentation showing that it is not possible to install and operate controls by the 2027 ozone season, despite all good faith efforts to comply and due to circumstances entirely beyond its control. The request must be received by the EPA at least 180 days before the extended compliance date and must include, at minimum, the same types of information as that required for the initial extension request. The owner or operator of an affected unit remains subject to the initial extended compliance date unless and until the Administrator grants a second compliance extension. A denial will be effective on the date of denial.

As discussed earlier in section VI.A, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.'' [284] This standard is met when, in the EPA's judgment, compliance by the attainment date amounts to an impossibility. The EPA cannot allow a covered industrial source to avoid timely compliance with the emissions control requirements established in this final rule unless the source owner/operator can demonstrate that compliance by the 2026 ozone season is not possible due to circumstances entirely beyond their control. The criteria that must be met to qualify for limited extensions of time to comply are designed to meet this statutory mandate. The EPA anticipates that the majority of the industrial sources covered by this final rule will not qualify for a compliance extension.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA is revising 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. The EPA is using 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

[284] *Wisconsin,* 938 F.3d 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'').

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. Thus, while the Step 3 control-stringency determination for EGUs to eliminate significant contribution is based on strategies that do not require generation shifting or reduced utilization of EGUs, 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.

To ensure emissions reductions necessary to eliminate significant contribution are maintained, in this rulemaking, the EPA is making certain enhancements to the current provisions of the Group 3 trading program addressing emissions-control performance by some kinds of individual units that will necessarily reduce the flexibility of the program to some extent for those units. In analyzing significant contribution at Step 3, once a linkage has been established between an upwind state and a downwind receptor, we identify an appropriate set of emissions control strategies, considering cost and other factors, that would eliminate significant contribution from the upwind state without leading to undercontrol or overcontrol at the downwind linked receptors. At Step 4, for EGUs, we develop emissions budgets based on consistent application of the identified strategies to the sources. This level of emission control at each source identified in Step 3 is what the EPA deems to eliminate significant contribution, while the design of emission budgets that successfully implement that level of emission control is determined at Step 4. See section III.B and V.

The trading program enhancements discussed in this section are designed to ensure that sources actually achieve that level of emission control and thereby eliminate significant contribution on a permanent basis at Step 4. The enhancements ensure that the emissions budgets for EGUs continue to secure the level of emission control identified at Step 3 at the sources active in the trading program on a more consistent basis throughout each ozone season than prior transport trading programs (including those that did not provide complete remedies for interstate pollution transport) have required. An alternative form of implementation at Step 4 would be to implement source-specific emissions limitations (*e.g.,* rate-based standards expressed as mass per unit of heat input) reflecting the control strategies identified at Step 3. This is a very common form of implementation for many other CAA requirements and is indeed the manner of implementation selected in this very rulemaking for other affected industrial sources. See sections III.B, V.D.4, and VI.C. But doing so would require loss of the flexibilities inherent in a trading program, inclusive of these enhancements, that facilitate orderly and timely achievement of the required emission reductions in the power sector.

Prior to this rule, the Group 3 trading program has applied 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 will 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 is expanding 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 seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 trading program to the revised Group 3 trading program at the beginning of the 2023 control period,[285] and affected EGUs within the borders of the three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period on the effective date of this rule.

[285] Affected EGUs in the three other states currently covered by the Group 2 trading program—Iowa, Kansas, and Tennessee—will continue to participate in that program.

As discussed in section VI.B.12.a of this document, because the effective date of the rule will likely be sometime during the 2023 ozone season, special transitional provisions have been developed to allow for efficient administration of the rule's EGU requirements through the Group 3 trading program while not imposing any new substantive obligations on parties prior to the rule's effective date, similar to the transitional provisions implemented under the Revised CSAPR Update.

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 will include new units as well as existing units and will also include units located in Indian country within the state's borders. Sections VI.B.2 and VI.B.3 of this rule provide additional discussion of the geographic expansion of the Group 3 trading program and the units in the expanded geography that will 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 is modifying the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements will 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 is revising the trading program regulations to include a dynamic budgeting procedure. Under this procedure, the EPA will calculate emissions budgets for control periods in 2026 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2024 ozone season and following (*e.g.,* for 2026, data from periods through 2024; for 2027, data from periods through 2025; etc.). Through the 2029 control period, the dynamically determined budgets will apply only if they are higher than preset budgets established in the rule. (Associated revisions to the program's variability limits and unit-level allowance allocation procedures will coordinate these provisions with the revised budget-setting procedures.) Second, starting with the 2024 control period, the EPA will 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 a preset percentage of the sum of the state emissions budgets for each control period. The preset percentage will be 21 percent for control periods through 2029 and 10.5 percent for control periods in 2030 and later years. Together, these enhancements will protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and will better sustain over time the incentives created by the trading program to achieve the degree of emissions control for EGUs that the EPA has determined is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program 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 coal-fired EGUs with existing SCR controls and the earlier of the 2030 control period or the control period after which an SCR is installed for other large coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu will apply as a backstop to the seasonal emissions budgets (which are based on an assumed seasonal average emissions rate of 0.08 lb/mmBtu for EGUs with existing SCR controls). Each ton of emissions exceeding a unit's backstop daily emissions rate, after the first 50 such tons, in a given control period will 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.,* typically 121 percent of the state's emissions budget), will be strengthened by the addition of another backstop requirement. Specifically, for any unit equipped with post-combustion controls that is found responsible for contributing to an exceedance of the state's assurance level, the revised regulations will 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.[286]

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 all units with post-combustion 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 the 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 V of this document. 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 better ensure that each state's significant contribution is fully eliminated by this action, *see North Carolina,* 531 F.3d at 919–21. In addition to addressing the statutory requirements of eliminating significant contribution, the EPA anticipates that these enhancements will also deliver public health and environmental benefits to underserved and overburdened communities.

The revisions to the Group 3 trading program being finalized in this rule are very similar to the proposed revisions. The changes from proposal to the set of states covered are driven largely by updates to the air quality modeling performed for the final rule, as described in section IV of this document. The changes from proposal to the trading program enhancements are generally being made in response to comments on the proposal, as discussed in more detail in the remainder of section VI.B of this document.

[286] 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 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 protective 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 have been nearly identical in their core design elements and their regulatory text.[287] 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 the 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 the 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

[287] 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.

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 CSAPR programs do not limit trading of allowances, and prior to this rule have not limited banking of allowances within a given trading program, the 3-for-1 surrender ratio imposed by the 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.[288]
- 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 the 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 historical CSAPR trading program structure established by the common design elements just described 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 many stakeholders' concerns about whether the historical 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 protectiveness and short-term form of the ozone standard. One set of concerns relates to the historically observed tendency under the 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 or run less optimally existing emissions controls even when a linkage between the sources' state and a receptor persists. For example, certain units in Ohio and Pennsylvania have been found to have operated their controls below target emissions performance levels used for budget setting under the CSAPR Update in the 2019–2021 period, even though the Revised CSAPR Update found that these states remained linked through at least 2021 to receptors for the 2008 ozone NAAQS, and the CSAPR Update itself was only a partial remedy. *See* 86 FR 23071, 23083. While this unit-level behavior may have been permissible under the prior program, 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. This indicates that the prior program design was not effectively ensuring the elimination of significant contribution.[289]

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 ensure emissions control on critically important highest ozone days, guard against non-operation of emissions controls under a more protective NAAQS, and provide assurance of elimination of significant contribution to downwind areas, while also maintaining appropriate compliance and operational flexibility for EGUs, the EPA in this rule is implementing a suite of enhancements to the trading program. These will help to ensure reductions occur on the highest ozone days commensurate with our Step 3 determinations, in addition to maintaining a mass-based seasonal requirement. To meet the statutory mandate to eliminate significant contribution and interference with

[288] As discussed in section VI.B.6 of this document, while allowance banking has not previously been limited under any of the CSAPR trading programs, limits on the use of banked allowances were included in the earlier NO_X Budget Trading Program in the form of ''flow control'' provisions.

[289] We also observe that these sources' emissions have the potential to impact downwind overburdened communities. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E. The EPA conducted a screening-level analysis to determine whether there may be impacts on overburdened communities resulting from those EGUs receiving backstop emissions rates under this rule. This analysis identified a greater potential for these sources to affect areas of potential concern than the national coal-fired EGU fleet on average. However, this analysis is distinct from the more comprehensive exposure analysis conducted as discussed in section VII of this document and the RIA. In addition, we note that our conclusions regarding the EGU trading program enhancements in this final rule are wholly supportable and justified under the good neighbor provision, even in the absence of any potential benefits to overburdened communities.

maintenance on the critically important days, this combination of provisions will strongly incentivize sources to plan to run controls all season, including on the highest ozone days, while giving reasonable flexibility for occasional operational needs.[290]

In this rulemaking, the EPA is revising the Group 3 trading program to include enhancements designed to address both sets of concerns described previously. The principles guiding the various revisions and the relationships of the revisions to one another are discussed in sections VI.B.1.b and VI.B.1.c of this document. The individual revisions are discussed in more detail in sections VI.B.4 through VI.B.9 of this document.

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 performance level as the EGU fleet evolves over time. Under the historical structure of the 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 historical 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 at Step 3, the EPA has then for purposes of Step 4 implementation program design 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 conditions unfold in practice that differ from the projections made at the time of a rulemaking for these other factors, 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 beyond the relatively near-term analytic years of 2023 and 2026 given particular attention in this rulemaking has become increasingly challenging in light of the anticipated continued evolution of the electric power sector toward more efficient and cleaner sources of generation, including as driven by incentives provided by the Infrastructure Investment and Jobs Act as well as the Inflation Reduction Act.

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 four 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).[291] 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.[292] [293] While the EPA had previously provided analysis focusing on the year of initial program implementation, when allowance prices were high (*i.e.,* 2017 for the CSAPR Update), to demonstrate that on average, sources operate their controls more effectively on high electric demand days, even in that case it had identified situations where particular units failed to optimize their controls on these days. In later years, when allowance prices had fallen, more sources, including some identified by commenters, had idled or reduced the effectiveness of their controls. Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies identified in the CSAPR Update to eliminate significant contribution to nonattainment and interference with maintenance, despite the fact that the mass-based budgets were being met.

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

[290] Deferral of the backstop daily emissions rate for certain EGUs, for reasons discussed in section VI.B.7 of this document, does not alter this finding that this trading program enhancement is an important part of the solution to eliminating significant contribution from EGUs under CAA section 110(a)(2)(D)(i)(I).

[291] The price of allowances in CSAPR Update states started 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).

[292] 86 FR 23117.

[293] *See* EPA–HQ–OAR–2020–0272–0094 (''[This] 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).'').

years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters in that rulemaking 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 2022, it appears that the emissions budgets set for the first two control periods covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for those control periods. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources will likely lead to a surplus of allowances after the adjustments end. This prospect for the existing Group 3 trading program should be avoided by the changes being made in this rulemaking. In this rulemaking, besides establishing new preset emissions budgets for the 2023 through 2029 control periods, the EPA is also extending the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely calculate dynamic emissions budgets for each future control period from 2026 on, to be published in the year before that control period, with each dynamic emissions budget generally reflecting the latest available information on the composition and utilization of the EGU fleet at the time that dynamic emissions budget is determined. For the control periods in 2026 through 2029, each state's final emissions budget will be the preset budget determined for the state in this rulemaking except in instances when the dynamic budget determined for the state (and published approximately one year before the control period using the dynamic budget-setting methodology) is higher. For control periods in 2030 and thereafter, the emissions budgets will be the amounts determined for each state in the year before the control period using the dynamic budget-setting methodology.

The current budget-setting methodology established in the Revised CSAPR Update and the revisions being made to that methodology are discussed in detail in section VI.B.4 of this document and the Ozone Transport Policy Analysis Final Rule TSD. To summarize here, the methodology used to determine the preset budgets largely follows the Revised CSAPR Update's emissions budget-setting methodology, which included 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 has determined the preset state emissions budgets for the control periods from 2023 through 2029 by using the Revised CSAPR Update's budget-setting methodology, except that the step of that methodology intended to reflect the effects of generation shifting has been eliminated.

The dynamic budget-setting methodology used to determine dynamic state emissions budgets in the year before each control period starting with the 2026 control period is set forth in the revised Group 3 trading program regulations at 40 CFR 97.1010(a). This methodology modifies the Revised CSAPR Update's budget-setting methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, will be updated for each control period using the most recent available reported data in combination with reported data from the four immediately preceding years. For example, in early 2025, using the final data reported for 2020 through 2024, the EPA will update the baseline inventory and heat input data used to determine dynamic state emissions budgets for the 2026 control period.[294] Second, the EPA will 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 reported heat input data used to update the baseline.

The EPA believes that the revisions to the emissions budget-setting process will substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The dynamic budget-setting methodology will 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, and through 2029 the preset budgets established in the rule will also account for these factors to the extent known. The dynamic budget-setting methodology will 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 dynamic budget-setting procedure is specified in this final rule's trading program regulations and the computations, which are straightforward, can be performed in a spreadsheet to deliver reliable results. The EPA will provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and will provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the dynamic budgets for each control period by May 1 of the year before the control period to which those dynamic budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2025, of the dynamic emissions budgets that will be calculated for the 2026 control period that starts May 1, 2026. Moreover, as of the issuance of this final rule, stakeholders will know the state-level preset emissions budgets for the 2026–2029 control periods, which serve as floors that will only be supplanted by dynamic budgets calculated for those control periods if such a dynamic budget yields a higher amount of tons than the corresponding preset budget established in this action.

It bears emphasis that the annually updated information used in the dynamic budget-setting computations will concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in those computations. The dynamically determined emissions budget computations for all years will reflect only the specific emissions control

[294] As discussed in section VI.B.4 of this document, the state-level data used to determine the overall state-level heat input for computing a state's dynamic budget will be a three-year average (*e.g.,* 2022–2024 state-level data will be used in 2025 to set the 2026 dynamic budgets). The unit-level data used to determine individual units' shares of the state-level heat input in the computations will be the average of the three highest non-zero heat input amounts for the respective units over the most recent five years (*e.g.,* 2020–2024 unit-level data will be used in 2025 to set the 2026 dynamic budgets).

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 will eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets will simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and will do so more consistently over time than the EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The rule's revisions relating to state emissions budgets and the budget-setting process generally follow the proposal except for two changes we are making in response to comments, specifically: we will use historical data from multiple years rather than a single year in the dynamic budget-setting process, and we are establishing preset emissions budgets for the 2026–2029 control periods such that the dynamic budgets for those control periods will only be imposed where they exceed the corresponding preset budgets finalized in this rule. The rationale for these changes is discussed later in this section as part of the responses to the relevant comments. Details of the final budget-setting methodology and responses to additional comments are discussed further in section VI.B.4 of this document.

The final rule's provisions relating to the determination of state-level variability limits and assurance levels and unit-level allowance allocations are coordinated with the budget-setting methodology. These provisions generally follow the proposal except that the change to the methodology for determining variability limits is implemented starting with the 2023 control period instead of the 2025 control period and the final methodology for determining unit-level allocations of allowances to coal-fired units considers the controlled emissions rate assumptions applicable to the same units in the budget-setting process. Details of these provisions, including the rationales for the changes from proposal, are discussed in sections VI.B.5 and VI.B.9, 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 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,[295] 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 allowance 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 VI.B.6 of this rule, the EPA is revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances that will 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 will 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 level computed as a target percentage of the sum of the state emissions budgets for the current control period. The target percentage will be 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years. The recalibration procedure entails identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the recalibration and then, if the ratio is 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.

As noted previously, recalibration of the bank for each control period will be carried out in August of that control period. This timing will accommodate the process of deducting allowances for compliance for the previous control period, which cannot be completed before sources' June 1 compliance deadline for the previous control period, and will then provide approximately two additional months for sources to engage in any desired allowance transactions before recalibration occurs. However, data that can be used to estimate the bank recalibration ratio for each control period will be available shortly after the end of the previous control period, and the EPA will use these data to make information on the estimated bank recalibration ratio for each control period publicly available no later than March 1 of the year of that control period, thereby facilitating the ability of affected EGUs to anticipate their ultimate holdings of recalibrated banked allowances to inform their compliance planning for that control season. Affected EGUs will also have several months following the completed bank recalibration in August to transact allowances with other parties as needed

[295] 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. 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. Therefore, section VI.B.1.c of this document discusses the enhancements to the Group 3 trading program that the EPA is making 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.

before the allowance transfer deadline of June 1 of the following year.

The EPA believes this revision to the Group 3 trading program's banking provisions establishing an annual bank recalibration process will complement the revisions to the budget-setting process by preventing 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.

The calibration procedure will 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 will be left in the account after the recalibration for possible sale or use in meeting future compliance requirements. Because the banked allowances will always have value, the opportunity to bank allowances will continue to advance the purposes served by otherwise unrestricted banking as described previously. 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 final rule's provisions relating to bank recalibration generally follow the proposal except that, in response to comments, the target percentage used to determine the recalibrated bank levels for the 2024–2029 control periods is being set at 21 percent instead of 10.5 percent. The rationale for this change is discussed later in this section as part of the responses to the relevant comments. Details of the bank recalibration provisions are discussed further in section VI.B.6 of this rule.

c. 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 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.

This EPA intends that the trading program enhancements described in section VI.B.1.b of this rule will improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance will 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 to the elimination of significant contribution in keeping with the EPA's Step 3 determinations, the EPA is supplementing the previously discussed enhancements with two other new sets of provisions that will apply to certain individual units within the larger context of the Group 3 trading program. The allowance price will continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements will be important supplemental drivers of performance and will offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by more continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the 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 will 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) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement will 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 will have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered will 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, computing the amount of any excess over 50 tons, and multiplying by two. Starting with the second control period in which newly installed SCR controls are operational, but not later than the 2030 control period, the 3-for-1 surrender ratio will apply in the same way to all large coal-fired EGUs except circulating fluidized bed units, consistent with EPA's determination that a control stringency reflecting installation and operation of SCR controls on all such large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

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.[296] 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 in section V.B.1.a of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-optimization to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of subsequent-year data for prior programs suggests that the non-optimization

[296] *E.g.,* comments of Maryland Department of the Environment on the proposed Revised CSAPR Update at 3, EPA–HQ–OAR–2020–0272–0094.

behavior increases in the latter years of a program. Applied to this context (*e.g.,* a rule providing a full remedy to interstate transport for the more protective 2015 ozone NAAQS and an extended period of expected persistence of receptors), this data suggests this deterioration in performance could become prevalent and problematic in future years if not addressed. 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 rule to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more protective 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 emissions 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. 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 Policy Analysis Final Rule 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. Thus, the EPA is adopting backstop daily rate limits at the individual unit level because it is appropriate and justified in the context of eliminating significant contribution under CAA section 110(a)(2)(D)(i)(I). While the former justification is sufficient to finalize this enhancement to the trading program, we also anticipate that this measure will deliver public health and environmental benefits to overburdened communities (as well as the rest of the population).[297]

We considered whether, as some commenters suggested, it would be appropriate to simply implement unit-specific daily emissions limitation at all of the large, coal-fired EGUs, and forego an emissions trading approach altogether. While this is within the EPA's statutory authority, *see* CAA section 110(a)(2)(A) and 302(y), and merits careful consideration, we are declining to do so in this action but intend to closely monitor EGU emissions performance in response to the trading program finalized here. The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional allowance surrender requirements instead of as an enforceable emissions limitation 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 VI.B.7 of this document, under the EPA's historical trading programs without the enhancements made 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. Collectively, this non-optimization of existing controls has a detrimental impact on problematic receptors. Table V.D.1–1 shows the expected air quality benefit from control optimization (totaling nearly 1.6 ppb change across all receptors).[298]

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 included in Appendix G of the Ozone Transport Policy Analysis Final 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 emissions 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.[299]

The EPA believes that the design of the daily emissions rate provisions will 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 will 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. Moreover, the EPA believes that the inclusion of a 50-ton threshold before the increased surrender requirements would apply is sufficient to address virtually all instances where a unit's emissions would exceed the 0.14 lb/mmBtu daily rate because of unavoidable startup or shutdown conditions during which SCR equipment cannot be operated, thereby ensuring that the provision will not penalize units for emissions that are beyond their reasonable control.

The EPA is applying 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 a common practice for the best 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 and installed on nearly 100 percent of the coal fired boilers in the top quartile of emissions rate performance. In the context of addressing good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is determining that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs (other than circulating fluidized bed units) is appropriate at Step 3. Finally, where SCR controls are installed on such units, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions

[297] Nonetheless, the environmental justice exposure analysis indicates that preexisting disparities among demographic groups are likely to persist even under this final rule. *See* section VII of this document.

[298] As illustrated in the table and underlying data, a small portion of this ppb impact is attributable to combustion control upgrade potential.

[299] EPA–HQ–OAR–2020–0272–0094.

reductions. The EPA believes these considerations support establishment of the 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 including some SCR controls at gas-fired steam units in the selected control stringency at Step 3, the EPA is not including universal SCR controls at gas-fired steam units. Because the EPA is not determining 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 applying 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 level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in section VI.B.7 of this document. 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 will 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 will be reflected in the state emissions budgets under this rule. For these units, not applying the daily average rate provisions until 2024 serves three purposes. First, it provides 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 will be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it provides 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 will apply to the SCR-equipped units based on the combined NO_X emissions rates measured in the common stacks. Third, it provides all units sufficient time to update the data handling software in their existing monitoring systems as needed to compute and report the additional hourly and daily data values needed for implementation of the provisions.[300]

With respect to the units without existing SCR controls, the daily average emissions rate provisions will apply starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. This implementation timing represents a change from the proposal, under which the daily average emissions rate provisions would have applied to units without existing SCR starting in the 2027 control period. Commenters noted that for many units without SCR, replacement of the unit within a few years, and shifting of some generation to cleaner units in the interim, would be a more economic compliance strategy than installation of new SCR controls. The commenters further noted that implementation of the daily average emissions rate for these units starting in 2027 would strongly disadvantage such an alternative strategy if the capacity replacement and any associated transmission improvements could not be implemented by 2027. In light of these comments, the EPA has determined that as long as the emissions budgets determined in this rule to eliminate significant contribution are still being implemented as expeditiously as practicable—which in this instance the EPA has determined requires phasing in the required emissions reductions by 2027—it is reasonable to defer implementation of the daily average emissions rate provisions to 2030 for units without SCR to allow temporarily greater flexibility to pursue compliance strategies other than installation of new controls. This lag is permissible consistent with the obligation to eliminate significant contribution for reasons that are further discussed in response to comments in section VI.B.1.d of this document. However, for any units that choose a compliance strategy of installing new SCR controls before 2030, the daily average emissions rate provisions would apply in the second control period of operation. Specification of the second control period rather than the first control period provides the unit operators with an opportunity to gain operational experience with the new equipment before the units will be held to increased allowance-surrender consequences for exceeding the daily rate.

The unit-specific daily emissions rate provisions are being finalized as proposed except for two changes noted in the previous summary: the exclusion from extra allowance surrender requirements of a unit's first 50 tons of emissions in a control period exceeding the backstop daily rate, and the revision of the starting date for implementation of the requirement for units without existing SCR controls to 2030 or the second control period of SCR operation, if earlier. The rationale for these changes is further discussed in the responses to comments later in this section. Additional details of the unit-specific daily emissions rate provisions are discussed in section VI.B.7 of this document.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations for units with post-combustion controls starting with the 2024 control period. The secondary emissions limitations will be determined on a unit-specific basis according to each unit's individual performance but will 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 percent 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 consists of a prohibition on NO_X emissions during the control

[300] For further discussion of emissions monitoring and reporting requirements under the rule, including the options available to plants where SCR-equipped and non-SCR-equipped coal-fired units exhaust to common stacks, see section VI.B.10 of this document.

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 secondary emissions limitation is in addition to, not in lieu of, the primary emissions limitation applicable to each source, which continues 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 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 unit-specific secondary emissions limitation takes 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 establishing 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, 906–08 (D.C. Cir. 2008). The EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the evidence of foreseeable and avoidable exceedances of the assurance levels demonstrates that EPA's existing approach has not been sufficient to accomplish this.

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 correcting 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 purpose of the secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations will strengthen the incentives for individual units with post-combustion controls to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. The new limitations will strengthen the incentives to operate and optimize the controls continuously, which 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 levels. Better emissions performance on average across the ozone season by individual units likely will also help address impacts of pollution on overburdened communities downwind from some such units. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E.

The unit-specific secondary emissions limitations are being finalized as proposed except that the limitations will apply only to units with post-combustion controls. The rationale for this change, and additional details regarding the provisions, are discussed in section VI.B.8 of this document.

d. Responses to General Comments on the Revisions to the Group 3 Trading Program

This section summarizes and provides the EPA's responses to overarching comments received on the EPA's proposal to implement the emissions reductions required from EGUs under this rule through expansion and enhancement of the Group 3 trading program originally established in the Revised CSAPR Update, particularly comments on electric system reliability. Responses to comments about individual aspects of the enhanced trading program are addressed in the respective subsections of this section in which those aspects are discussed. Responses to comments concerning alleged overcontrol and the EPA's legal authority are in sections V.D. and III. Comments not addressed in this document are addressed in the separate *RTC* document available in the docket for this action.

Comment: Some commenters, including EGU owners, states, and several RTOs, expressed concern that the requirements for EGUs as formulated in the proposal could lead to a degradation in the reliability of the electric system. As background, some of these commenters noted that the power sector is currently undergoing rapid change, with older and less economic fossil-fuel-fired steam generating units retiring while the majority of the new capacity being added consists of wind and solar capacity. They noted that fossil-fuel-fired generating capacity provides reliability benefits not necessarily provided by other types of generating capacity, including not only the ability to generate electricity in the absence of wind or sunlight, but also inertia, ramping capability, voltage support, and frequency response. Commenters stated that past EGU retirements and the pace of change in the generating capacity mix have already been stressing the electric system in some regions, and that the forecasted risk of events where the electric system would be unable to fully meet load is rising.

For purposes of their comments, these commenters generally assumed that the rule would lead to additional retirements of fossil-fuel-fired generating capacity beyond the retirements that EGU owners have already planned and announced. Some of the commenters also suggested that remaining fossil-fuel-fired generators would be unwilling to operate when needed because allowances might be unavailable for purchase or too costly. In the context of an already-stressed electric system, the commenters predicted that these assumed consequences of the rule would threaten resource adequacy and result in degraded electric reliability. To support their assumptions concerning additional retirements, some of the commenters pointed to projections of incremental generating capacity retirements included in the results of modeling performed by the EPA to analyze the costs and benefits of the proposed rule. Some commenters indicated that they expected EGU owners to be interested in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and expressed concern that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy; for these commenters, 2027 and the immediately following years were the period of greatest concern. Some commenters appear simply to have assumed that owners of units not already equipped with SCR controls would choose to retire the units as of the ozone season in which the units would otherwise become subject to the backstop daily emissions rate provisions, regardless of whether replacement investments had been completed.

Some of the commenters raising concerns about electric system reliability suggested potential modifications to the proposed rule that the commenters believed could help address their concerns. The suggestions included various mechanisms for suspending some or all of the trading program's requirements for certain EGUs at times when an RTO or other entity responsible for overseeing a region of the interconnected electrical grid determines that generation from those EGUs is needed and the EGUs might not otherwise agree to operate. Other suggestions focused on ways of providing EGUs with greater confidence that allowances would be available to cover their incremental emissions during particular events. A number of commenters used the term ''reliability safety valve,'' in some cases with reference to the types of suggestions just mentioned and in other cases without details. Some commenters pointed to the ''safety valve'' provision included in the Group 2 trading program regulations under the Revised CSAPR Update. Another commenter pointed to provisions for a ''reliability safety valve'' included in the Clean Power Plan (80 FR 64662, Oct. 23, 2015).

In addition to offering critiques and recommendations concerning the proposed rule's contents, some commenters claimed that the EPA had failed to conduct sufficient analysis of the potential implications of the proposed rule on electrical system reliability. These commenters called on the EPA to consult with RTOs and other entities with responsibilities relating to electric system reliability and to perform additional analysis. Some commenters advocated for renewed consultations and analysis before each planned adjustment to emissions budgets under the dynamic budget-setting process. Commenters cited the consultation processes followed during implementation of other EPA rules, such as the Mercury and Air Toxics Standards (MATS) (77 FR 9304, Feb. 16, 2012).

Response: The EPA disagrees with the comments asserting that this rule would threaten resource adequacy or otherwise degrade electric system reliability. The emissions reduction requirements for EGUs under this rule are being implemented through the mechanism of an allowance trading program. Under the trading program, no EGU is required to cease operation. The core trading program requirements for a participating EGU are to monitor and report the unit's NO_X emissions for each ozone season period and to surrender a quantity of allowances after the end of the ozone season based on the reported emissions. To address states' obligations under the good neighbor provision, some units of course will have to take some type of action to reduce emissions, the actions taken to reduce emissions will generally have costs, and some EGU owners will conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some comments nevertheless assume that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service. Assumptions of this nature are simply not reasonable. Like many commenters, the EPA does expect that retirement will be viewed as a more economic compliance strategy for some EGUs than installing new controls, but the Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected. The trading program inherently provides ample flexibility to allow such an orderly transition to take place. In addition, as discussed later in this section, the EPA has adopted several changes in the final rule to increase flexibility specifically for the early years of the trading program for which commenters have indicated the greatest concerns about electric system reliability.

As an initial matter, the EPA notes two fundamental aspects of this rulemaking which together provide a strong foundation for the Agency's conclusion that the emissions reductions required from EGUs can be achieved with no adverse impacts on electric system reliability. First, there is ample evidence indicating that the required emissions reductions are feasible. As discussed in section V of this document, the magnitude and timing of the EGU emissions reductions required by this action reflect application of technologies that are already in widespread use, on schedules that are supported by industry experience. Second, the required emissions reductions are being implemented through the mechanism of a trading program. The enhanced trading program under this rule, like the trading programs established by the EPA under prior rules, provides EGU owners with opportunities to substitute emissions reductions from sources where achieving reductions is cheaper and easier for emissions reductions from other sources where achieving reductions is more costly or difficult. In general, an EGU owner has options to operate the emissions controls identified by the EPA for that type of unit (including installation or upgrade of controls where necessary), operate other types of emissions controls, or adapt the unit's levels of operation to produce less generation if the unit is a higher-emitting EGU or more generation if the unit is a lower-emitting EGU. The backstop daily emissions rate provisions in this rule reduce the degree of available flexibility relative to the degree of flexibility in the Agency's previous trading programs under CAIR and CSAPR but by no means eliminate it. Moreover, even the backstop rate provisions are structured as requirements to surrender additional allowances rather than as hard limits, providing a further element of flexibility No EGU is required to retire or is prohibited from operating at any time under this rule. EGUs only need to surrender of the appropriate quantities of allowances after the end of the control period.[301]

Further, in the large number of comments submitted in this rulemaking that assert concerns over electric system reliability, no commenter has cited a single instance where implementation of an EPA trading program has actually caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior trading program rulemakings have shown a considerable gap between rhetoric and reality. For example, in the litigation over the industry's multiple motions to stay implementation of CSAPR, claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets despite CSAPR not being in effect.[302] Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emissions reduction targets without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own. . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). The claims that these rules would have had adverse reliability impacts were proved to be groundless.

Notwithstanding the long experience confirming the ability of the EPA's trading programs to obtain emissions reductions from EGUs without impairing the sector's ability to provide reliable electric service, the Agency of course does not rely here solely on its experience, but has carefully reviewed the comments on this topic for any information that might indicate the appropriateness of modifications to the enhanced trading program as proposed. In recognition of the important role that RTOs play in ensuring electric system reliability, and consistent with the requests of some commenters, the EPA has engaged in outreach to the RTOs that commented on the proposal to better understand their comments specifically and the reliability-related comments of other commenters more generally.[303] Through these meetings, the central reliability-related concern was identified as one of timing. In order for retirement to be a viable compliance strategy for a unit that cannot be entirely spared until replacement investments in generation or transmission are completed, it must be possible for the unit to operate at critical times for a transition period. Like other stakeholders, the RTOs perceived implementation of the backstop daily emissions rate provisions on uncontrolled units as materially strengthening incentives for such units to either install controls or retire. The RTOs were concerned that the option for a coal-fired unit without SCR controls to maintain limited operation while surrendering allowances at a 3-for-1 ratio for all emissions exceeding the backstop daily rate was one that EGU owners would be reluctant to pursue. Accordingly, the RTOs expected considerable interest from EGU owners in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and they were concerned that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy. The RTOs described their concerns as greatest through approximately the 2029 control period.

The RTOs also described a concern about potentially illiquid allowance markets. They believed it was possible that some EGUs might claim an inability to operate at particular times when needed unless they had confidence that they would be able obtain additional allowances. The RTOs were particularly concerned that introduction of dynamic budgeting as proposed would create uncertainty for some EGUs regarding the quantities of allowances they would have available for use, particularly given the potentially large year-to-year swings if budgets were based on historical data from a single year. Some of the RTOs suggested potential solutions for these issues, principally in the form of auctions or RTO-administered allocations of allowances from pools of supplemental allowances, with access to the supplemental allowances triggered by certain indications of temporary stress on the electric system.

In the final rule, the EPA is adopting several changes from the proposal to help address the reliability-related concerns that were identified in comments and brought into greater focus by the consultations with the RTOs. The first change adopted in response to these comments is that application of the backstop daily NO_X emissions rate to units without existing SCR controls is being deferred until the 2030 control period, or the second control period in which a unit operates new SCR controls, if earlier. The purpose of this change is to address the concerns that application of the backstop daily NO_X emissions rate to EGUs without existing SCR starting in 2027 would provide insufficient time for planning and investments needed to facilitate unit retirement as a compliance pathway, which some commenters noted they prefer or have already planned. In particular, where an EGU owner would prefer to retire and replace an uncontrolled EGU rather than to install new controls, and in recognition that reliability-related needs may require some degree of operation from such units in the period before the investments needed to replace the unit can be completed, deferral of the backstop daily emissions rate provisions ensures that the necessary generation can be provided without being made subject to a 3-for-1 allowance surrender ratio that might render that compliance strategy uneconomic compared to the faster but less environmentally beneficial compliance strategy of installing new controls. The EPA has considered the statutory mandate that states' good neighbor obligations—

[301] The EPA has prepared a resource adequacy assessment of the projected impacts of the final rule showing that the projected impacts of the final rule on power system operations, under conditions preserving resource adequacy, are modest and manageable. See *Resource Adequacy and Reliability Analysis Final Rule TSD,* available in the docket.

[302] For a state-by-state comparison, see Appendix G of the Ozone Transport Policy Analysis Final Rule TSD.

[303] The EPA also met with non-RTO balancing authorities that submitted comments. Memoranda identifying the dates, attendees, and topics of discussion of these meetings with RTOs and non-RTO balancing authorities are available in the docket.

including this action's requirement for large coal-fired EGUs to make emissions reductions commensurate with good SCR operation—be addressed as expeditiously as practicable. The EPA has also considered the fact that in this rule, the backstop daily emissions rate serves as a supplement to the broader requirement for emissions reductions commensurate with application of several control technologies at several types of EGUs, encompassing the extent of emissions reductions that would be incentivized by the backstop emissions rate requirement. The EPA views the backstop daily emissions rate as part of the solution to eliminating significant contribution in that it strongly incentivizes emissions-control operation throughout each day of the ozone season. *See* sections III.B.1.d, VI.B.1.b, VI.B.1.c.i. For that reason, in general we are finalizing the daily backstop emissions rate for units that have SCR installed or that install it in the future. It is only as an exception to that general rule that we defer the backstop daily emissions rate given the transition period and reliability concerns identified by commenters. The EPA finds that in this circumstance, as long as state emissions budgets continue to reflect the required degree of emissions reductions, deferral of the backstop rate requirement for uncontrolled units for a transition period can be justified on the basis of the greater long-term environmental benefits obtained through facilitating the replacement of these affected EGUs with cleaner sources of generation. Beginning in the 2030 ozone season, all coal-fired EGUs identified for SCR retrofit potential in this action will be subject to the backstop daily emissions rate. Any such units that remain in operation in that year can and should meet the backstop daily emissions rate or be subject to the heightened allowance surrender ratio.

The second change from the proposal adopted in response to the reliability-related comments is that the target percentage of the states' emissions budgets used to recalibrate the target bank level will be set at the proposed 10.5 percent starting in the 2030 control period, and for the control periods from 2024 through 2029, a target percentage of 21 percent will be used instead. The adoption of the higher target percentage for use through the 2029 control period is intended to promote greater allowance market liquidity during a period of relatively rapid fleet transition about which commenters expressed more focused reliability-related needs. As discussed later in this section, the EPA expects the introduction of the bank recalibration process in 2024 generally to boost market liquidity (by discouraging allowance hoarding) and also considers the target percentage of 10.5 percent set forth in the proposal well supported. Nevertheless, the Agency agrees with suggestions by commenters that, at least in the early years of the enhanced trading program, a larger bank would provide further liquidity and would give program participants greater confidence that allowances would be available for purchase when needed. Greater confidence by sources would help address RTOs' concern about the possibility that some sources could be reluctant to operate if they were unsure of their ability to procure allowances to cover their emissions. In finding that this modification from proposal is appropriate, the EPA has considered the fact that use of a higher target percentage will not result in the creation of any additional allowances in any control period, because under the recalibration provisions, when the total quantity of allowances banked from the previous control period is less than the bank target level, the consequence is not that additional allowances are created to raise the bank to the target level, but simply that no bank adjustment is carried out. We also note that while including an annual bank recalibration of any percentage is an enhancement in the trading program from prior trading programs under the good neighbor provision established in the CAIR, CSAPR, CSAPR Update, and Revised CSAPR Update rulemakings, it is not unprecedented; the trading program established under the NO_X SIP Call included ''progressive flow control'' provisions that were designed differently from the bank recalibration provisions in this rule but had the same purpose and general effect.

The third change from the proposal adopted in response to the reliability-related comments is that the EPA is determining preset state emissions budgets not only for the control periods in 2023 and 2024 as proposed, but also for the control periods in 2025 through 2029. Finalizing preset state emissions budgets through 2029 will establish predictable amounts for the minimum quantities of allowances available during the period when commenters have expressed concern that the reliability-related need for such predictability is greatest. Moreover, the EPA will also determine state emissions budgets using the final dynamic budget-setting methodology for the control periods in 2026 through 2029, and for each state and control period, the dynamic budget to be published in the future will only supplant the preset budget finalized in this rule for a control period in which that dynamic budget is higher than the corresponding preset budget. The reason for using dynamic budgets when they are higher than the corresponding preset budgets is that the EPA recognizes that evolution of the EGU fleet will not follow the exact path projected at the time of the rulemaking, and that by not accounting for certain events, the preset methodology could result in issuance of smaller quantities of allowances than the EPA would find consistent with the quantities of emissions from a well-controlled EGU fleet using the dynamic budget-setting methodology. Events that could cause preset budgets to underpredict a state's well-controlled emissions, which are more likely in years farther in the future from the time of the rulemaking, include deferral of a large EGU's previously planned retirement date or increases in electricity demand that outpace the general trend of lower-emitting or non-emitting generation replacing higher-emitting generation. After considering the commenters' interest in greater predictability during the early years of the amended trading program as well as the need to protect against instances where the preset budgets could underpredict a state's well-controlled emissions in years farther from the year of the rulemaking, the EPA finds that the combination of these factors justifies the approach of using the higher of the two budgets for the control periods from 2026 through 2029.

In addition to the changes made in response to reliability-related comments, several other changes to the proposal being adopted primarily for other reasons will also help address the factors identified as reliability-related concerns. Most notably, the EPA is adopting changes to the dynamic budget computation procedure to incorporate multiple years of heat input data, which will reduce year-to-year variability in the budgets determined under that procedure and should to some extent reduce uncertainty about the quantities of allowances available for use in instances where a dynamic budget is being used instead of preset budget. In addition, the adoption of a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate should ensure that no unit incurs the higher surrender ratio solely because of unavoidable emissions during startup and should help address concerns that some units might be reluctant to operate because of the associated emissions-related costs. Also, the 2026–2027 phase-in of emissions reductions commensurate with installation of new SCR controls will increase the quantities of allowances available in the 2026 state emissions budgets for most states in the trading program.

To summarize: in light of the strong record supporting the feasibility of the emissions reductions required from EGUs; the use of a trading program as the mechanism for achieving those emissions reductions, with multiple options for achieving compliance and no requirements to cease operation of any individual EGU at any time; the established processes of RTOs, other balancing authorities, and state regulators for managing any EGU retirement requests that do occur in an orderly manner with evaluation of potential reliability impacts and implementation of mitigation measures where needed; the unbroken, decades-long historical success of the EPA's trading programs at achieving emissions reductions without any adverse reliability impacts; the views expressed by commenters that facilitating EGU retirement and replacement as a possible compliance strategy through 2029 would be particularly helpful; the changes made in the final rule for control periods through 2029 specifically to increase flexibility during this transitional period, including deferring application of the backstop daily emissions rate provisions for EGUs without existing SCR controls, increasing the target percentage used to determine the target allowance bank level for purposes of the bank recalibration provisions, and establishing preset state emissions budgets which serve as floors against potential dynamic budget imposition in those control periods; and the changes made in the final rule incorporating multiple years of heat input data into the dynamic budget-setting procedure, adding a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate, and phasing in emissions reductions requirements commensurate with new SCR installations through 2027; the EPA concludes that this action does not pose any material risk of adverse impact to electric system reliability.

The EPA has also considered the other suggestions offered by commenters for addressing reliability-related issues. With respect to suggestions that the rule should include provisions allowing some or all of the trading program's requirements to be suspended at times when an RTO or other entity with grid management responsibilities determines there is a reliability-related need, the EPA again observes that the rule's emissions reduction requirements are being implemented through a trading program mechanism which makes exceptions of this nature unnecessary. Trading programs inherently offer the flexibility to accommodate variability in the utilization of individual units. The ''reliability safety valve'' provisions in the Clean Power Plan, which one commenter cited as a precedent to support some form of temporary exemption under this rule, in fact was available only in situations where a state plan did not allow emissions trading and instead imposed unit-specific emissions constraints. *See* 80 FR 64877–879. Even the 3-for-1 allowance surrender ratio under the backstop daily NO_X emissions rate provisions can be met through the surrender of additional allowances. The rule does not bar any EGU from operating at any time as long as all allowance surrender requirements are met.

With respect to suggestions that the EPA must undertake recurring modeling of the evolving electrical system and consult with RTOs before each planned adjustment to emissions budgets, which start from the premise that the rule poses risk to electric system reliability that must be continuously monitored, the EPA disagrees with the premise and therefore also disagrees with the suggestions. As discussed in section V of this document, the EPA has taken care to ensure that the emissions reduction requirements applicable to EGUs under this rule are feasible through application of the control technologies selected as the basis of the emissions reductions. The EPA has also performed modeling in this rulemaking to assess the benefits and costs of the rule when all required emissions reductions are achieved. That modeling, which incorporates a representation of electrical grid regions and interregional constraints on energy and capacity exchange, affirms the feasibility of the overall emissions reduction requirements and is illustrative of a control strategy where some units retire and are replaced instead of installing new controls. The EPA has also consulted with the RTOs (as well as other balancing authorities) in the course of this rulemaking to ensure that the EPA understood the concerns expressed in their comments such that we could address those comments in this final rule. The EPA does not agree that further modeling or ongoing consultations with RTOs are needed in advance of the recurring dynamic budget adjustments, which do not increase the stringency of the rule's emissions reduction requirements established in the final rule. The extensive consultation processes adopted by the Agency in conjunction with the MATS rulemaking are not a relevant precedent; the MATS rule, which was promulgated to address a different statutory mandate, was structured in the form of unit-specific emissions constraints, fundamentally different from the requirements of this rule. The EPA notes that other entities responsible for maintaining reliability and managing entry and exit of resources, including the North American Electric Reliability Corporation (NERC) and RTOs and other balancing authorities, already routinely assess resource adequacy and reliability inclusive of meeting all regulatory requirements, including environmental requirements.

While the EPA does not agree that such consultations are a necessary precondition for successful implementation of this rule, the Agency remains available to engage with any affected EGU or reliability authority requesting to meet and discuss the intersection of its power sector regulatory programs with electric reliability planning and operations. The EPA is also continuing its practice of meeting with the U.S. Department of Energy and the Federal Energy Regulatory Commission to maintain mutual awareness of how Federal actions and programs intersect with the industry's responsibility to maintain electric reliability.[304]

The EPA is not adopting the suggestion to replicate the so-called ''safety valve'' mechanism created under the Revised CSAPR Update. That mechanism, cited by some commenters as potential precedent for an unspecified form of ''reliability safety valve'' in this action, gave owners of covered EGUs a one-time opportunity to voluntarily convert allowances banked under the Group 2 trading program to allowances useable in the Group 3 trading program at an 18-for-1 ratio for use in the trading program's initial control period in 2021. *See* 82 FR 23137–138. EGU owners chose to use the voluntary mechanism to acquire a total of 382 allowances, representing only 0.36 percent of the sum of the state emissions budgets and only 0.26 percent

[304] *See, e.g.,* U.S. Department of Energy and U.S. Environmental Protection Agency, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (March 8, 2023), available at *https://www.epa.gov/power-sector/electric-reliability-mou.*

of the total quantity of allowances available for compliance in that control period.[305] For the 2023 control period, the bank of allowances carried over from the 2022 control period plus the incremental starting bank that will be created by conversion of additional allowances banked under the Group 2 trading program (see section VI.B.12.b of this document) will total over 30 percent of the full-season emissions budgets.[306] Given the larger starting bank and this rule's bank recalibration provisions (which will be implemented starting with the 2024 control period, but which the EPA expects will increase allowance market liquidity starting with the 2023 control period), the Agency views establishment of a one-time voluntary conversion opportunity for the 2023 control period analogous to the Revised CSAPR Update's ''safety valve'' provision as unnecessary.

Finally, in the final rule the EPA is not adopting any of the other suggestions concerning additional mechanisms to make additional allowances available through auctions or RTO-administered allowance pools. For the reasons discussed throughout this section, the EPA concludes that the trading program as established in this action provides a flexible compliance mechanism that will allow the required emissions reductions to be achieved without the need for creation of additional allowances. However, the EPA also recognizes the potential for allowance market liquidity to be further increased through some form of auction mechanism. For instance, it may be appropriate to pair the introduction of an auction with a reduction in the bank recalibration percentage that begins earlier than 2030. Through a supplemental rulemaking, the Agency intends to propose and take comment on potential amendments to the Group 3 trading program that would add such an auction mechanism to the regulations and make other appropriate adjustments in the implementation framework at Step 4.[307]

2. Expansion of Geographic Scope

In light of the findings at Steps 1, 2, and 3 of the 4-step interstate transport framework, the EPA is expanding the geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass additional states (and Indian country within the borders of such states) with EGU emissions that significantly contribute for purposes of the 2015 ozone NAAQS. Specifically, the EPA is expanding the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and Wisconsin. Any unit located in a newly added jurisdiction that meets the applicability criteria for the Group 3 trading program will become an affected unit under the program, as discussed in section VI.B.3 of this document.

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.[308] In contrast, within the 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 meet the program's applicability criteria. Issues related to state, tribal, and Federal CAA implementation planning authority with respect to sources in Indian country in general and in these areas in particular are discussed in section III.C.2 of this document. EPA's approach for determining a portion of each state's budget for each control period that will 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 VI.B.9 of this document.

Units within the borders of each newly added state will 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 necessary is that, as discussed in section VI.B.12.a of this document, the effective date is expected to 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—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the 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, Texas, and Wisconsin—the sources will begin participating in the Group 3 trading program on May 1, 2023, regardless of the 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 will not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources historically 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 VI.B.12.a of this document contains further discussion of the rationale for this approach and the specific transitional provisions.

The EPA notes that under the rule, the expanded Group 3 trading program will include not only 19 states for which the EPA is determining that the required control stringency includes, among other measures, installation of new post-combustion controls, but also three

[305] Additional allowances available for compliance under the Group 3 trading program in the 2021 control period included a starting allowance bank created through mandatory conversion of a portion of the allowances banked under the Group 2 trading program as well as supplemental allowances issued to ensure that no provisions of the Revised CSAPR Update increasing regulatory stringency would take effect before that rule's effective date. *See* 86 FR 23133–137.

[306] The full-season emissions budgets for the 2023 control period under the Group 3 trading program and the incremental starting bank created in this action through conversion of additional Group 2 allowances (but not the bank of allowances carried over from the 2022 control period under the Group 3 trading program) will be prorated to reflect the portion of the 2023 ozone season occurring after the effective date of this rule. See sections VI.B.12.a. and VI.B.12.b.

[307] Such a rulemaking would not reopen any determinations which the Agency has made at Steps 1, 2, or 3 of the interstate transport framework in this action. Nor would it reopen any aspects of implementation of the program at Step 4 except for those in relation to establishing an auction and associated adjustments to ensure program stringency is maintained. In this respect, such a rulemaking would constitute a discretionary action that is not necessary to resolution of good neighbor obligations. Rather, these adjustments, if finalized, would reflect a shift from one acceptable form of implementation at Step 4 to a slightly modified but also acceptable form of implementation at Step 4, as related to EGUs. No legal or technical justification for this action as set forth in the record here depends on or would be undermined by the development of an alternative approach that includes an auction, and if the EPA for any reason determines not to propose or finalize such a rulemaking, no aspect of this rule would thereby be rendered infeasible or incomplete.

[308] 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 III.C.2.a.

states—Alabama, Minnesota, and Wisconsin—for which the EPA is determining 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, 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 enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions are being substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in sections VI.B.1.c.ii and VI.B.8. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in sections VI.B.1.c.i and VI.B.7 will 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 is necessary for sources in Alabama, Minnesota, and Wisconsin to be excluded from the revised Group 3 trading program simply because their emissions budgets reflect a different selected emissions control stringency than the other states in the program.

The EPA's legal and analytic bases for expansion of the Group 3 trading program to each of the additional covered states, as well as responses to the principal related comments, are discussed in sections III, IV, and V of this document, respectively, and responses to additional comments are contained in the *RTC* document. With respect to the proposed approach of including all states covered by the rule in a single trading program even where the assigned control stringencies differ, the only comments received by the EPA supported the approach, which is finalized as proposed.

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 applicability of this rule to MWCs and cogeneration units outside the Group 3 trading program is discussed in sections V.B.3.a and V.B.3.c of this document, respectively, and MWC applicability criteria are further discussed in section VI.C.6 of this document.

In this rulemaking, the EPA did not propose and is not finalizing any revisions to 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 will 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 additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin (including Indian country within the borders of such states)—will also become subject to the Group 3 trading program.

In the additional states where other CSAPR trading programs are not currently in effect—Nevada and Utah (including Indian country within the borders of such states)—units already subject to the Acid Rain Program under that program's applicability criteria (*see* 40 CFR 72.6) generally also meet the applicability criteria for the Group 3 trading program. 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, 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 the Group 3 trading program even if they are not subject to the Acid Rain Program. Using data reported to the U.S. Energy Information Administration, in the proposal the EPA identified six sources in Nevada and Utah (and Indian country within the borders of the states) with a total of 15 units that appear to meet the general applicability criteria for the Group 3 trading program and that do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program. These units were listed in a table in the proposed rule, and the data from that table for these units are reproduced as Table VI.B.3–1 of this document. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposed to use for the unit when determining state emissions budgets if the unit was ultimately treated as subject to the Group 3 trading program.[309] The EPA requested comment on whether each listed 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 and whether the estimated historical heat input and emissions data identified for each unit

[309] As discussed in section VI.B.10, any unit that becomes subject to the Group 3 trading program pursuant to this rule and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 will not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, in order to provide time for installation and certification of the required monitoring systems. Such a unit will 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.

were representative. With respect to the listed units within the borders of Nevada or Utah, the EPA received no comments asserting either that the units qualified for applicability exemptions or that the estimated data identified by the EPA were unrepresentative.[310] For purposes of this rule, the EPA is therefore presuming that the units listed in Table VI.B.3–1 do not qualify for applicability exemptions and that the estimated data shown in the table for each unit are representative. However, the owners and operators of the sources retain the option to seek applicability determinations under the trading program regulations at 40 CFR 97.1004(c).

TABLE VI.B.3–1—ESTIMATED DATA TO BE USED FOR PRESUMPTIVELY AFFECTED UNITS WITHIN THE BORDERS OF NEVADA AND UTAH THAT DO NOT REPORT UNDER THE ACID RAIN PROGRAM

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	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	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTB	CT	660,100	0.0387	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTC	CT	660,100	0.0387	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTA	CT	749,778	0.0323	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTB	CT	749,778	0.0370	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTC	CT	749,778	0.0364	1
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	1
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	1
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	

Table notes:
[1] Unit reports capability of producing both electricity and useful thermal energy.

4. State Emissions Budgets

In this final rule, the EPA is using a combination of a ''preset'' budget calculation methodology and a ''dynamic'' budget calculation methodology to establish state emissions budgets for the Group 3 trading program. A ''preset'' budget is one for which the absolute amount expressed as tons per ozone season control period is established in this final rule. It uses the latest data currently available on EGU fleet composition at the time of this final action. A ''dynamic'' budget is one for which the formula and emissions-rate information is finalized in this rule, but updated EGU heat input and inventory information is used on a rolling basis to set the total tons per ozone season for each control period. Both methods of budget calculation are designed to set budgets reflective of the emissions control strategies and associated stringency levels (expressed as an emissions rate of pounds of NO_X per mmBtu) identified for relevant EGU types at Step 3—which we will refer to in this section as the ''Step 3 emissions control stringency.'' Preset budgets provide greater certainty for planning purposes and can be reliably established in the short-term based on known, upcoming changes in the EGU fleet. Due to build time for new units and planning and approval processes for plant retirements, these major fleet alterations are often known several years in advance. This information facilitates presetting budgets that appropriately calibrate the identified control stringency to the fleet. Dynamic budgets better assure that the budgets remain commensurate with the Step 3 emissions control stringency over the longer term, as currently unknown changes in the EGU fleet occur. In this final rule, in response to comments, we have adjusted the proposal to give a greater role for preset budgets through 2029, while dynamic budgeting will be phased in to provide greater certainty in the short term and allow for a transition period to an exclusively ''dynamic'' approach beginning in 2030.

For the control periods from 2023 through 2025, the preset budgets established in the rule will serve as the state emissions budgets for the control periods in those years, with no role for dynamic budgeting. For the control periods from 2026 through 2029, the EPA is determining preset emissions budgets for each control period in the rule and will also calculate and publish dynamic budgets for each state in the year before each control period using the dynamic budget-setting methodology finalized in this rule, applied to data available at the time of the calculations. For these four control periods, each state's preset budget serves as a floor and may be supplanted by the dynamic emissions budget EPA calculates for the state for that control period only if the dynamic budget is higher than the preset budget. For control periods in 2030 and thereafter, the state emissions budgets will be the dynamic budgets calculated and published in the year before each control period.

In the dynamic budget calculation methodology, it is the fleet composition (reflected by heat input patterns across the fleet in service, inclusive of EGU entry and exit) that is dynamic, while the emissions stringency finalized in this rule is constant, as reflected in

[310] One commenter expressed the view that eight of the listed units within Nevada's borders appear to meet the CSAPR applicability criteria but provided no comments on the specific proposed data. See comments of Berkshire Hathaway Energy, EPA–HQ–OAR–2021–0668–0554, at 58–59. The EPA also received comments concerning sources within Delaware's borders that were included in the proposal's request for comment; these comments are moot because Delaware is not being added to the Group 3 trading program in the final rule. See comments of Calpine, EPA–HQ–OAR–2021–0668–0515; comments of Delaware City Refining, EPA–HQ–OAR–2021–0668–0309.

emissions rates for various types of units. Multiplying the assumed emissions rate for each unit (as finalized in this rule) by the identified recent historical heat input for each unit and summing the results to the state level would provide a given year's state dynamic emissions budgets. Dynamic budgets are a product of the formula promulgated in this action applied to a rolling three-year average of reported heat input data at the state level and a rolling highest-three-of-five-year average of reported heat input data at the unit level. As such, the EPA is confident that dynamic budgets will more accurately reflect power sector composition, particularly in later years, and certainly from 2030 and beyond, than preset budgets could and will therefore better implement the Step 3 emissions control stringency over long time horizons.

Starting in 2025 (for the 2026 control period), the dynamic budgets, along with the underlying data and calculations will be publicly announced, and this will occur approximately one year before the relevant control period begins. These will be published in the **Federal Register** through notices of data availability (NODAs), similar to how other periodic actions that are ministerial in nature 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.

To illustrate how dynamic budgeting will work after the transition from preset budgets, the dynamic budgets for the 2030 ozone season control period will be identified by May 1, 2029, using the latest available average of three years of reported operational data at that time (*i.e.,* the average of 2026–2028 heat input data at the state level and 2024–2028 years of rolling data at the unit level) applied in a simple mathematical formula finalized in this rule, which multiplies this heat input data by the emissions rates quantified in this rule. Therefore, if a unit retires before the start of the 2028 ozone season but had not announced its upcoming retirement at the time of this rule's finalization, the dynamic budget approach ensures that the dynamic budgets for 2030 and subsequent control periods would represent the identified control stringency applied to a fleet reflecting that retirement.

The two examples discussed next illustrate the implementation of the dynamic budget during the 2026–2029 time period. During this period, the state emissions budget for each state for a given control period will be the preset state emissions budget unless the dynamic budget is higher. This approach accommodates scenarios where baseline fossil heat input may exceed levels anticipated by EPA in the preset budgets (*e.g.,* this could result from greater electric vehicle penetration rates). Table VI.B.4–1 illustrates this scenario. In the preset budget approach for 2028, the 2028 heat input is estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021; see the subsection on preset budget methodology later in this section), which cannot reflect a subsequent change in fleet heat input values (column 2) due to, *e.g.,* increased utilization to meet increased electric load. However, the dynamic budget would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet utilization levels, and when multiplied by the emissions rates reflecting the Step 3 emissions control stringency in this final rule, the corresponding emissions (18,700 tons) summed in column 4 constitute a state budget that more accurately reflects the Step 3 emissions control stringency applied to the fleet composition for that year, as opposed to the 17,000 tons identified in the preset budget approach. As illustrated in the example, the dynamic variable is the heat input variable, which changes over time. In this instance, the dynamic budget value of 18,700 tons would be implemented for 2028 instead of the preset value, and thus accommodate the unforeseen utilization changes in response to higher demand.

In the second table, Table VI.B.4–2, the dynamic budget is lower than the preset budget due to retirements that were not foreseen at the time the preset budgets were determined. In the preset budget approach for 2028, the 2028 heat input is still estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021), which cannot reflect a subsequent fleet change in heat input values due to an unanticipated retirement of one of the state's coal-fired units before the start of the 2028 ozone season. However, the dynamic budget again would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget, which would reflect the decline in coal heat input and replacement with natural gas heat input (capturing the coal unit's retirement). Therefore, the heat input values under the dynamic budget scenario reflect the change in fleet composition, and when multiplied by the relevant emissions rates reflecting the Step 3 emissions control stringency identified in this final rule, the corresponding emissions (15,000 tons) constitute a state budget that 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. However, for the 2026–2029 period, in which the EPA implements an approach that utilizes the higher of the dynamic budget or preset budget, the budget implemented for 2028 in this scenario would be the 17,000 ton preset amount.

During the 2026–2029 transition period—during which substantial, publicly announced utility commitments exist for higher emitting units to exit the fleet—it is still possible that yet-to-be known, unit-specific retirements (such as illustrated in this second scenario) may result in dynamic budgets that are lower than the preset budgets finalized in this rule. However, during this transition period EPA believes that having the preset budgets serve as floors for the state emissions budgets is appropriate for two primary reasons identified by commenters. First, commenters repeatedly emphasized the need for certainty and flexibility to successfully carryout plans for significant fleet transition through the end of the decade. The 2026–2029 period is expected to have substantial fleet turnover. Current Form EIA–860 data, in which utilities report their retirement plans, identify 2028 as the year with the most planned coal capacity retirements during the 2023–2029 timeframe. Using preset budgets as state emissions budget floors provides states and utilities with information on minimum quantities of allowances that can be used for planning purposes. In turn, this fosters the operational flexibility needed while putting generation and transmission solutions into place to accommodate such elevated levels of retirements. Second, the latter part of the decade has a significant amount of unit-level firm retirements already planned and announced for purposes of compliance with other power sector regulations or fulfillment of utility commitments. These known retirements are already captured in the preset state budgets, with the result that the likelihood and magnitude of instances where a state's dynamic budget for a given control period would be lower than its preset budget for the control period is reduced in this 2026–2029 period relative to control periods further in the future for which retirement plans have not yet been announced. After 2029, the dynamic budgets from 2030 forward will fully capture all prior retirements and new builds when the fleet is entering this period where unit-specific data on such plans is less frequently available. For instance, through the remaining portion of the decade, the amount of coal steam retirements identified and reported through Form EIA–860 is nearly 7 GW each year. However, for the decade beginning in 2030—the amount of capacity currently reported with a planned retirement is less than 2 GW each year.[311] This yet-to-be available data and relative lack of currently known firm retirement plans for 2030 and beyond make dynamic budget implementation for those years essential for state emissions budgets to maintain the Step 3 control stringency required under this rule.

TABLE VI.B.4–1—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF INCREASED FOSSIL HEAT INPUT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	660	0.05	16,500
Gas Units	400	0.01	2,000	440	0.01	2,200
State Budget (tons)			17,000			18,700

TABLE VI.B.4–2—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF UNANTICIPATED RETIREMENT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × 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

In summary, for the control periods in 2023 through 2025, EPA is providing only preset budgets in this final rule because those control periods are in the immediate future and would not substantially benefit from the use of future reported data. For these years, the certainty around new builds and retirements is higher than ensuing years. For the ozone season control periods of 2026 through 2029, EPA is providing both preset budgets in this final rule and dynamic budgets via future ministerial actions. For those control periods from 2026 through 2029, the preset budgets finalized in this rule serve as floors, such that a given state's dynamic budget ultimately calculated and published for that control period will apply to that state's affected EGUs only if it is higher than the corresponding preset budget finalized in this rulemaking. This approach is in response to stakeholder comments requesting more advance notice regarding the total quantities of allowances available to accommodate compliance planning through the latter half of the decade, during a period of particularly high fleet transition expected with or without this rulemaking.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Final Rule TSD and summarized later in this section.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 Through 2029 Control Periods

To compose preset state emissions budgets, the EPA is using the best available data at the time of developing this final rule regarding retirements and new builds. The EPA relies on a compilation of data from Form EIA–860 (where facilities report their future retirement plans), the PJM Retirement Tracker, utilities' integrated resource plans, notification of compliance plans with other EPA power sector regulatory requirements, and other information sources that EPA routinely canvasses to populate the data fields included in the Agency's NEEDS database. The EPA has updated this data on retirements and new builds using the latest information available from these sources at the time of final rule development as well as input provided by commenters.

For determining preset state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data available to EPA and to commenters responding to this rulemaking's proposal and providing a reasonable representation of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update and the Revised CSAPR Update, where

[311] See 2021 Form EIA Form 860—Schedule 3, Generator Data. Department of Energy, Energy Information Administration.

the EPA likewise began with data for the most recent ozone season at the time of proposal (2015 and 2019, respectively).

By using historical unit-level NO_X emissions rates, heat input, and emissions data in the first stage of determining preset emissions budgets, the EPA is grounding its budgets in the most recent representative historical operation for the covered units at the time EPA began its final rulemaking. This data set is a reasonable starting point for the budget-setting process as it reflects recent publicly available and quality assured data reported by affected facilities under 40 CFR part 75, largely using CEMS. 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 first step in deriving the future year state emissions budget is to calibrate historical data to planned future fleet conditions. EPA does this by adjusting this historical baseline information to reflect the known changes (*e.g.,* when deriving the 2023 state emissions budget, EPA starts by adjusting 2021 unit-level data to reflect changes announced and planned to occur by 2023). The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes expected to occur in the baseline. This includes announced and confirmed retirements, new builds, and retrofits that occur after 2021 but prior to 2023. For example, if a unit emitted in 2021, but retired prior to May 1, 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the EPA uses the actual emissions, heat input, and emissions rates reported for 2021 as the baseline starting point for calculating the 2023 state emissions budgets. 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).

The second step in deriving the preset state emissions budgets is for EPA to take the adjusted historical data from Step 1, and adjust the emissions rates and mass emissions to reflect the control stringencies identified as appropriate for EGUs of that type. For instance, if an SCR-equipped unit was not operating its SCR so as to achieve a seasonal average emissions rate of 0.08 lb/mmBtu or less in the historical baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's mass 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. The improved emissions rate of 0.08 lb/mmBtu is applied to this constant heat input, reflecting control optimization. In this manner, the unit-level totals from Step 1 are adjusted to reflect the additional application of the assumed control technology at a given control stringency. This is illustrated in Table VI.B.4.a–1. Row 1 reflects the 2021 historical data for this SCR-controlled unit. Row 2 reflects no change (as there are no known changes such as planned retirement or coal-to-gas conversion). Row 3 reflects application of the Step 3 stringency (*i.e.,* a 0.08 lb/mmBtu emissions rate from SCR optimization). The resulting impact on emissions is a reduction from the historical 4,700 tons to an expected future level of 615 tons. A state's preset budget for a given control period is the sum of the amounts computed in this manner for each unit in the state for the control period.

TABLE VI.B.4.a–1—EXAMPLE OF UNIT-LEVEL DATA CALCULATIONS FOR DERIVING STATE EMISSIONS BUDGETS

	Heat input (tBtu)	Emission rate (lb/mmBtu)	Emissions (tons)
Historical Data (2021)	15.384	0.61	4,700
Step 1 (Baseline)—Historical data adjusted for planned changes	15.384	0.61	4,700
Step 2—Baseline further adjusted for Step 3 stringency	15.384	0.08	615

For each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Minnesota, and Wisconsin 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 Final Rule TSD. The emissions rates assigned to large coal-fired EGUs for 2026 state emissions budget computations only reflect 50 percent of the SCR retrofit emissions reduction potential at each of those units, to capture the phase-in approach EPA is taking for this control as described in section VI.A of this document. The EPA calculates these unit-level emissions rates in 2026 as the sum of the unit's baseline emissions rate and its controlled emissions rate divided by two (*i.e.,* 50 percent of the emissions reduction potential of that pollution control measure). The emissions rates assigned to these large coal-fired EGUs for 2027 state emissions budget computations reflect the full assumed SCR retrofit emissions potential at those units, by applying the controlled emissions rate only. For example, a coal steam unit greater than or equal to 100 MW currently lacking a SCR and emitting at 0.20 lb/mmBtu would be assumed to reduce its emissions rate to 0.125 lb/mmBtu rate in 2026 and 0.050 lb/mmBtu rate in 2027 for purposes of deriving its preset state emissions budgets in those years.

Comment: Some commenters suggested that EPA should not reflect planned retirements in its preset budgets. The suggestion stems from commenters' observation that those retirement decisions may yet change.

Response: The effectiveness of EPA's future year preset state emissions budgets depends on how well they are calibrated to the expected future fleet. Therefore, EPA believes it is important to incorporate expected new builds, retirements, and unit changes already slated to occur. Ignoring these factors would dilute, rather than strengthen, the ability of preset budgets to capture the most representative fleet of EGUs to which they will be applied. Omitting scheduled retirements and new builds from state emissions budgets would reflect units that power sector operators and planning authorities do not expect to exist, while failing to reflect units that are expected to exist.

EPA notes it is using the best available data at the time of the final rule. EPA relies on a compilation of data from Form EIA–860 where facilities report their future retirement plans. In addition, EPA is using data from regional transmission organizations who are cataloging, evaluating, and approving such retirement plans and data; data from notifications submitted directly to EPA by the utility themselves through comments; and retirement notifications submitted to permitting authorities. This information is highly reliable, real-world information that provides EPA with the high confidence that such retirements will in fact occur.

If a unit's future retirement does not occur on the currently scheduled date, EPA observes that such an unexpected departure from the currently available evidence would still not undermine the ability of affected EGUs to comply with their applicable state budgets. EPA's approach of using historical data and incorporation only of announced fleet changes in estimating its future engineering analytics baseline means that its future year baseline generation and retirement outlook for higher emitting sources is more likely to understate future retirements (rather than overstate as suggested by commenter), as EPA does not assume for the purpose of preset budget quantification any retirements beyond those that are already planned. In other words, in the 2023 through 2029 timeframe for which EPA is establishing preset state emissions budgets in this rulemaking, there are more likely to be additional future EGU retirements beyond those scheduled prior to the finalization of this rule than there are to be reversed or substantially delayed changes to already announced EGU retirement plans. For instance, subsequent to the EPA's finalization of the Revised CSAPR Update Rule budgets for 2023 (rule finalized in March 2021), the owners of Sammis Units 5–7 and Zimmer Unit 1 in Ohio (totaling nearly 3 GW of coal capacity) announced that the units would retire by 2023—nearly 5 years earlier than previously planned.[312] [313] These coal retirements were not captured in Ohio's 2023 or 2024 state emissions budgets established under the Revised CSAPR Update. Meanwhile, there have been no announcements of previously announced retirement plans being rescinded or delayed for other Ohio units. Similarly, the Joppa Power Plant in Illinois accelerated its retirement from 2025 to 2022 shortly after the Revised CSAPR Update Rule was signed.[314]

We further observe that the commenters' concern is only materially meaningful for the 2023 through 2025 preset budget periods, where the currently known information is generally the most reliable. For the 2026–2029 control periods, if an anticipated fleet change such as an EGU retirement does not actually occur, the dynamic budget setting methodology would, all else being equal, generate a budget reflective of that unit's continued operation (as the budget would be based on the preceding years of historical data), and that dynamic budget will supplant the preset budget for that state (if it represents a total quantity of emissions higher than the preset budget).

Because the future is inherently uncertain, all analytic tools and information resources used in any estimation of future EGU emissions will yield some differences between the projected future and the realized future. Such potential differences may either increase or decrease future emissions in practice, and the unavoidable existence of such differences does not, on its own, render the EPA's inclusion of currently announced retirements an unreasonable feature of the methodology for determining future year preset emissions budgets. To the contrary, if the EPA failed to include these announced retirements, the rule would knowingly authorize amounts of additional, sustained pollution that are not currently expected to occur. If those retirements largely or entirely occur as currently scheduled, the overestimated state budgets would allow other EGUs to emit additional pollution in place of the emissions from the retired EGUs instead of maintaining or improving their emissions performance to eliminate significant contribution with nonattainment and interference with maintenance of the NAAQS.[315]

Additionally, as noted elsewhere, EPA's use of a market-based program, a starting bank of converted allowances, and variability limits are all features that will readily accommodate whatever relatively limited differences in emissions may occur if a currently scheduled EGU retirement is ultimately postponed during the preset budget years of 2023 through 2025. Therefore, EPA's resulting preset state emissions budgets—inclusive of expected fleet turnover—are robust to the inherent uncertainty in future year baseline conditions for the period in which they are applied.

Comment: Some commenters suggested that EPA should use a multi-year baseline for all of its state budget derivations, including preset budgets, to control for outlier years that may not be representative of future years due to major weather events or other fleet disruptions (such as a large nuclear unit outage).

Response: For preset state emissions budget derivation, EPA is finalizing use of the same single-year[316] historical baseline approach it used in the proposed rule. This approach is similar to the Revised CSAPR Update, where EPA also relied on a single-year historical baseline to inform its Step 3 approach. EPA's interest in a historical data set to inform this part of the analysis is to capture the most representative view of the power sector. For estimating preset state budgets, EPA finds that, particularly at the state level, more recent data is a better representation and basis for future year baselines rather than incorporating older data. Taking as an example preset budget estimation for the 2023 through 2025 ozone seasons, the EPA is able to compare its single-year base line to an alternative multi-year baseline (*e.g.,* a 3-year baseline encompassing 2020–2022) and determine that the single year baseline better reflects future fleet operation expectation than a multi-year baseline that incorporates units which have since retired as well as outlier patterns in load during pandemic-related shutdowns.

EPA recognizes that 2021 is the latest available historical data as of the preparation of this rulemaking, and therefore the most up-to-date picture of the fleet at the time EPA began its analysis. EPA then further evaluates the 2021 historical data at the state level to determine whether it was a representative starting point for estimating future year baseline levels and subsequently deriving the preset state emissions budgets. If the Agency finds any state-level anomalies, it makes necessary adjustments to the data. While unit-level variation may occur from year-to-year, those variations are often offset by substitute generation from other units within the state. Therefore, EPA conducts its first screening at the state level by identifying any states where 2021 heat

[312] Available at *https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html.*

[313] Available at *https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/071921-vistra-plans-to-retire-13-gw-zimmer-coal-plant-in-ohio-five-years-early.*

[314] Available at *https://www.prnewswire.com/news-releases/joppa-power-plant-to-close-in-2022-as-company-transitions-to-a-cleaner-future-301263013.html.*

[315] Some of these announced retirements reflect the operator's reported intention to EPA to retire the affected capacity by that time as part of their compliance with effluent limitation guidelines or with the coal combustion residuals rule.

[316] For the purposes of this rulemaking, when describing a ''year'' or ''years'' of data utilized in state emission budget computations, the EPA is actually utilizing the relevant data from May 1 through September 30 of the referenced year(s), consistent with the control period duration of this rule's EGU trading program.

input and 2021 emissions were the lowest year for heat input and emissions relative to the past several years (2018–2022, excluding 2020 due to shut downs and corresponding reduced utilization related to the pandemic onset).[317] [318] Then, for that limited number of states (AL, LA, MS, and TX) in which 2021 reflects the minimum fossil fuel heat input and minimum emissions over the baseline evaluation period, EPA—similar to prior rules—evaluated whether any unit-level anomalies in operation were driving this lower heat input at the state level. EPA examined unit-level 2021 outages to determine where an individual unit-level outage might yield a significant difference in state heat input, corresponding emissions baseline and resulting state emissions budgets. When applying this test to all of the units in the previously identified states (and even when applying to EGUs in all states for whom Federal implementation plans are finalized in this rulemaking), the EPA determined that the only unit with a 2021 outage that (1) decreased its output relative to preceding or subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's emissions budget substantially as it constituted more than 5 percent of the state's heat input in a non-outage year was Daniel Unit 2 in Mississippi. EPA therefore adjusted this state's baseline heat input and NO_X emissions to reflect the operation of this unit based on its 2019 data—which was the second most recent year of data available at the time of proposal (excluding 2020 given atypical impacts from pandemic-related shutdowns) for which this unit operated. The EPA then applied the Step 3 mitigation strategies as appropriate to this unit (*i.e.,* combustion controls upgrade in 2024, SCR retrofit in 2026/2027) to derive this portion of Mississippi's budget. This test, and subsequent adjustment as necessary, enables EPA to utilize the latest, most representative data in a manner that is robust to any substantial state-level or region-level outlier events within that dataset and further validates EPA's comprehensive approach to using the most recent single year of data for preset budgets.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2026 onwards

In this final rule, the EPA is finalizing an approach of using multi-year baseline data for purposes of dynamic budget computation. The aforementioned testing of the representative nature of a single year of baseline data for purposes of preset budget setting is not possible in the dynamic budget process as that data will not be available until a later date. Further, the EPA generally agrees with commenters that use of a multi-year period will be more robust to any unrepresentative outlier years in fleet operation and thus better suited for purposes of dynamic budgets. The methodology for determining dynamic state emissions budgets for later control periods (2026 and beyond) relies on a nearly identical methodology for applying unit-level emissions rate assumptions as the preset budget methodology. But it uses more recent heat input data that will become available by that future time, employing a multi-year approach for identifying the heat input data so as to ensure representativeness.

For dynamic budgets, EPA uses more years of baseline data to control for any state-level and unit-level variation that may occur in a future single year that is not possible to identify at present. First, for each unit operating in the most recent ozone season for which data have been reported, EPA identifies the average of the three highest unit-level heat input values from the five ozone seasons ending with that ozone season to get a representative unit-level heat input. Ozone seasons for which a unit reported zero heat input are excluded from the averaging of the three highest heat input values for that unit. These representative unit-level heat input values established for each unit individually are then summed for all units in each state. Each unit's representative unit-level heat input is then divided into this state-level sum to get that unit's representative percent of the aggregated average heat input values for all affected EGUs in that state.

Next, EPA calculates a representative state-level heat input by taking the average state-level total heat input across affected EGUs from the most recent three ozone seasons for which data have been reported, to which the above-derived representative unit-level percentages of heat input are applied. The EPA uses a three-year baseline period for state-level heat input versus the five-year baseline period noted previously for unit-level heat input because there is less variation from year to year at the state level compared to the unit level. Multiplying the representative unit-level percentages of heat input by the representative state-level heat input yields a normalized unit-level heat input value for each affected EGU. This step assures that the total heat input being reflected in a dynamic state budget does not exceed the average total heat input reported by affected EGUs in that state from the three most recent years. Finally, each normalized unit-level heat input value is multiplied by the emissions rate reflecting the assumed unit-specific control stringency for each particular year (determined at Step 3) to get a unit-level emissions estimate. These unit-level emissions estimates are then summed to the state level to identify the dynamic budget for that year. This procedure to derive normalized unit-level heat input is captured in the following table:

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
Unit A	100	200	150	200	300	233	41%	483	199
Unit B	50	100	200	50	100	133	24	483	114
Unit C	250	150	150	200	100	200	35	483	170

[317] EPA identified states for which 2021 both heat input and emissions were the low year among the examined baseline period as a preliminary screen to identify potential instances where reduced utilization may lead to an understated emissions baseline value.

[318] EPA also conducted a similar test to identify states in which 2021 heat input and emissions were the high year among the examined baseline period and found that it was for both Utah and Pennsylvania. However, for both states the elevated heat input trend persisted into 2022 (at slightly lower levels and was correlated with retirements elsewhere in the region—indicating that some of this heat input increase may be representative of the future fleet and that planned retirements factored into preset budget will remove any unrepresentative heat input from 2021.

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT—Continued
[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
State Total	400	450	500	450	500	567			

The EPA will issue these dynamic budget quantifications approximately 1 year before the relevant control period. We view such actions as ministerial in nature in that no exercise of agency discretion is required. For instance, starting in early 2025, the EPA would take the most recent three years of state-level heat input data and the most recent five years of unit-level heat input data and calculate 2026 state emissions budgets using the methodology described previously. For 2026–2029, EPA is establishing the preset state emissions budgets finalized in this rulemaking and will only supplant those preset emissions budgets with the to-be-published dynamic emissions budgets if, for a given state and a given control period, that dynamic budget yields a higher level of emissions than the corresponding preset budget finalized in this rulemaking. For 2030 and beyond, the EPA solely uses the dynamic budget process.

By March 1 of 2025, and each year thereafter, the EPA will make publicly available through a NODA the preliminary state emissions budgets for the subsequent control period and will provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. (This process will be similar to the releases of data and preliminary computations for allocations from new unit set-asides that is already used in existing CSAPR trading programs.) By May 1 of 2025, and each year thereafter, the EPA will publish the dynamic budgets for the ozone-season control period in the following calendar year. Through the 2029 ozone season control period, these budgets will only be imposed if the applicable dynamic state budget is higher than the corresponding preset state budget finalized in this rulemaking. Preliminary and final unit-level allowance allocations for the units in each state in each control period will be published on the same schedule as the dynamic budgets for the control period. For the control periods from 2026 through 2029, the allocations will reflect the higher of the preset or dynamic budget for each state, and after 2030, the allocations will reflect the dynamic budgets. Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Final Rule TSD.

Comment: Multiple commenters claimed that designing a dynamic budget process that relies on a single year of yet-to-be known heat input data may produce an unrepresentative view of fleet operations for the immediate ensuing years. Commenters pointed to the hypothetical of another pandemic-like year (*e.g.,* 2020) occurring in the future, noting that 2020 would have been a poor choice for estimating 2022 fleet operation and the same would likely hold true if a similar event occurred, for example, in 2025—that would consequently make that year a poor choice as a representative of 2027 baseline. They further pointed out that severe weather events and operating disruptions (a large nuclear plant outage) can similarly render a single year baseline a risky choice to inform future expectations.

Response: Insofar as the commenters are addressing the reference period for dynamic budget computation regarding years of data that have not yet occurred and therefore not currently available for evaluating their representative nature, EPA agrees and is incorporating a rolling 3-year baseline at the state level and a rolling 5-year baseline at the unit level for determining dynamic budgets in this final rule. These multi-year rolling baseline (or reference periods) will minimize any otherwise undue impact from individual years where fleet-level or unit-level heat input was uncharacteristically high or low. EPA determined that such an approach, while not needed for preset budgets, is necessary in the case of dynamic budgets because the baseline in that instance is occurring in a future year and therefore is not knowable and available to test for representativeness at the time of the final rule. To control for this type of uncertainty, the EPA finds it appropriate to use a multi-year baseline in this instance per commenter suggestion. While a multi-year baseline may have a slight drawback of using a slightly more dated past fleet performance (including emissions from higher emitting EGUs that may have subsequently reduced utilization by the target year for which the dynamic budget is being calculated) to estimate the expected future fleet performance at the emissions performance levels determined by the Step 3 result in this rulemaking, that drawback is worth the advantage of protecting against instances where atypical circumstances in the most recent single year may occur and not be representative of the subsequent year for which the dynamic budget is being estimated. This singular drawback of moving to a multi-year baseline is most pronounced in the early years of dynamic budgeting. Therefore, EPA is able to lessen the impact of this drawback of the multi-year baseline by extending the earliest start date of dynamic budgets from 2025 (as proposed) to 2026 in the final rule.

Comment: Commenters suggested that the dynamic budget procedure would not provide enough advance notice of state budget and unit level allocation for sources to adequately plan future year operation.

Response: EPA disagrees with the notion that the timing of the dynamic budget determination would occur too close to the control period to allow adequate operations planning for compliance. As described previously, the dynamic budget level would be provided approximately 1 year in advance of the start of the control period (*i.e.,* around May 1), and the allowance allocations would occur on July 1, approximately 10 months prior to the start of the compliance period. Not only is this an adequate amount of time as demonstrated by the successful implementation of past rules that have been finalized and implemented within several months of the beginning of the first affected compliance period (*e.g.,* Revised CSAPR Update), but EPA notes it is maintaining similar trading program flexibility and banking flexibilities of past programs which provide further opportunities for sources to procure allowances and plan for any future operating conditions. Finally, as noted previously, the EPA is providing preset budgets for the years 2023–2029, which serve as an effective floor on the state's ultimate emissions budget level for years 2026–2029, as states will receive the higher of the preset or dynamic budget for those years. This provision of certain preset state emissions budgets serving as a floor level for 2026–2029 should further assuage commenters' concerns regarding planning certainty about allowance allocations and state emissions budget levels during this period of power sector transition to cleaner energy sources.

Comment: Commenters raised concerns that there is a two-year lag in the dynamic budgets in that, for example, for the dynamic budget in the 2026 control period, the calculations will be based on heat input and inventory information reflective of data through 2024. Commenters contend that, if there is a much greater need for allowances for compliance due to unavoidable or unforeseen need for a higher amount of heat input than reflected in prior years' data, the budget for that control period will not reflect this need, and the allowances will only become available when the dynamic budget is calculated using that information (*i.e.,* 2025 data would be reflected starting in the 2027 dynamic budget). According to commenters, this lag could present a serious compliance challenge. Other commenters raised a concern in the opposite direction about the potential ''slack'' created by the lag time—meaning that as high-emitting units retire, their emissions and operation will still inform the state emissions budgets for additional years beyond their retirement due to the lag.

Response: The EPA recognizes there will be a data lag inherent in the computation of future year dynamic emissions budgets, because the dynamic budgets will reflect fleet composition and utilization data from recent previous control periods rather than the control periods for which the dynamic budgets are being calculated. This means that the resulting dynamic budgets will reflect a limited lag behind the actual pace of the EGU fleet's trends. However, on the whole, those trends are clearly toward more efficient and cleaner generating resources. Thus, the data lag on the whole will inure to the compliance benefit of EGUs by resulting in dynamic budgets that are generally calculated at levels likely to be somewhat higher than what a dynamic budget calculation reflecting real-time EGU operations would produce. The EPA believes this data lag is worthwhile to provide more compliance planning certainty and advance notice to affected EGUs of the dynamic budget applicable to an upcoming control period. Furthermore, this data lag in dynamic budget computation is comparable to the data lag of quantifying preset state budgets for 2023 through 2025 based upon 2021 data, and at no point in the long history of EPA's trading programs has such a data lag in state budget computation yielded any compliance problems for affected EGUs. Without dynamic budgeting, the data lag inherent in calculating preset budgets would grow unabated with the passage of time, as a fixed reference year of heat input levels would continually apply regardless of potentially higher heat input levels farther and farther into the future. By eliminating the increase in the length of the data lag, this new dynamic budgeting approach is a substantial improvement in performance of the program relative to previous approaches that were not capable of capturing changes over time in the fleet and its utilization beyond the scheduled changes known to the EPA at the time of establishing preset budgets.

The EPA disagrees that this lag will in fact pose compliance challenges for EGUs even if the unlikely scenario described by commenters were to occur. Several factors influence this. First, the change in methodology to preset budgets serving as a floor on budgets through 2029 means that the dynamic budget methodology can only produce an increase in the budget from this final rule through that year. Second, the adoption of a multi-year approach for identifying the heat input used to calculate the dynamic budgets will smooth the year-to-year budget changes and effectively eliminate the possibility of greatest concern, which was that a single year of unusually low heat input would be used to set the budget for a subsequent year that turned out to have unusually high heat input. While a year of unusually high heat input for a given state may still occur, the state's budgets for those years will never be based on heat input from an anomalously low year, but instead will always be based on an average of several years' heat input. Third, because the Group 3 trading program is an interstate program implemented over a wide geographic region, and it is unlikely that all regions of the country would uniformly experience a marked increase in fossil fuel heat input necessitating an additional supply of allowances, it is likely that allowances will be available for trade from one area of the country where there is less demand to another area where there is greater demand. Fourth, as explained in section VI.B.5 of this document, each state's assurance level will adjust to reflect actual heat input in that year. Specifically, the EPA will determine each state's variability limit for a given control period so that the percentage value used will 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. Thus, if in year 2030, for example, a state's actual heat input levels increase to a level that is not reflected in the dynamic budget calculation using earlier years of data, the assurance level (which absent the unusually high heat input would be 121 percent of the state's budget) will be calculated by the EPA following the 2030 ozone season, using that higher reported heat input. This will avoid imposing a three-for-one allowance surrender penalty on sources except where emissions exceed the assurance level even factoring in the increase in heat input in that year. Finally, as some commenters observed, the inherent data lag in dynamic budget quantification means that a state budget for the year 2030 will continue to reflect emissions from any EGU that retires before the 2030 control period but is still operating anytime during the 2026–2028 reference years from which the 2030 dynamic budget will be calculated. Given the likely ongoing trend of relatively high-emitting EGU retirements over time, this method for determining dynamic budgets should further assist the ability of remaining EGUs to obtain sufficient allowances to cover future heat input levels.

With respect to the comments expressing concern that dynamic budgets would create too much slack because of the lag in incorporating retirements, the EPA observes that dynamic budgets will yield a closer representation of Step 3 control stringency across the future fleet than preset budgets for years in which retirement plans are currently relatively unknown. Moreover, any risk that the lag would lead to an unacceptably large surplus of allowances is limited by EPA's finalization of the annual bank recalibration to 21 percent and 10.5 percent of the budget beginning in 2024 and 2030 respectively. The corresponding risk that a lag will lead sources to not operate emissions controls, due to a surplus of allowances, is also limited by the backstop daily emissions rates that start in 2024 (for sources with existing SCR controls) and no later than 2030 for other coal-fired sources.

Comment: Commenters allege that the dynamic budget methodology is effectively a ''one-way ratchet'' because, if EGUs pursue compliance strategies such as reduced utilization or generation shifting to comply with the rule rather than install or optimize pollution controls pursuant to the identified Step 3 emissions control strategies, the effect will be that the dynamic budget calculated in a future year will reflect that reduced heat input, but the applied emissions rate assumption will be the same. Thus, the approach according to commenters actually ''punishes'' sources for achievement of emissions reductions commensurate with EPA's Step 3 determinations through alternative compliance means, by producing a smaller budget in later years (less heat input multiplied by the same emissions rate). If the source again reduces utilization or shifts generation to comply with this budget, then budgets in later years will again ratchet down, and so on.

Response: First, the claims of dynamic budgeting being a one-way ratchet are incorrect. As pointed out at proposal, the dynamic budget process would allow for increased utilization to result in increased budgets. Moreover, this concern is entirely mooted for the period 2026 through 2029 with the shift to preset budgets serving as a floor; dynamic budgeting can only increase the budget used in any given year in this time period. Additionally, the use of a multi-year average heat input in the budget-setting calculations will, on the whole, modulate the dynamic budgets such that the budgets over time will only gradually change with changes in the operating profile of the EGU fleet.

For the control periods 2030 and later, this rule is premised on the expectation that all large coal-fired EGU sources identified for SCR-retrofit potential will, if they continue operating in 2030 or later, have installed the requisite post-combustion controls. Thus, the backstop daily emissions rate applies for all such sources beginning in the 2030 ozone season. In this latter period (post-2030), the EPA disagrees that the dynamic budget will punish fleet segments seeking to continue to pursue a strategy of reduced utilization. Rather, the dynamic budget will simply continue to reflect the Step 3 emissions control stringency. For instance, if there are two otherwise high-emitting sources in a state that can reduce emissions by operating SCR, this rule's control stringency finds it cost effective for both sources to operate their controls. If one source retires and is replaced by new lower-emitting generation, it is not a punishment to have the budgets adjust in a way that still incentivize remaining units to operate their controls. This is simply right-sizing the budget to an evolving fleet. It is a feature of the rule, not a flaw, and is designed to address observed instances in prior rules where market-driven reduced utilization resulted in non-binding (*i.e.,* overly slack) budgets and corresponding conditions where the incentive to operate a control dissipated over time. In the event that sources reduce utilization whether for compliance purposes or market-driven reasons, that also does not obviate the importance of continuing to incentivize the Step 3 emissions control stringency at identified sources.

c. Final Preset State Emissions Budgets

For affected EGUs in each covered state (and Indian country within the state's borders), this final rule establishes preset budgets for the control periods 2023 through 2029. For control periods 2026 through 2029, any of those preset budgets may be supplanted by the corresponding dynamic budget that will be tabulated at later date, if and only if that dynamic budget yields a higher amount. For 2030 and beyond, the dynamic budget formula promulgated in this rule will be applied to future year data to quantify state emissions budgets for those control periods. The 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 VI.B.9 of this document. The amounts of the final preset state emissions budgets for the 2023 through 2029 control periods are shown in Table VI.B.4.c–1.

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS

[Tons] [a b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS—Continued

[Tons] [a] [b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

Table Notes:

[a] The state emissions budget calculations pertaining to Table VI.B.4.c–1 are described in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event this final rule becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period will be adjusted under the rule's transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date. The 2023 budget amounts shown in Table VI.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in section VI.B.12 of this document.

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program 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 principle that each state's sources must be held to the elimination of significant contribution within that 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 Group 3 trading program regulations in effect before this rulemaking was 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.[319]

In this rulemaking, the EPA did not propose and is not making changes to the basic structure of the Group 3 trading program's assurance provisions, which will 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 will continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[320] Each assurance level also will continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[321] However, the EPA is making a change to the methodology for determining the variability limits. Specifically, the EPA will determine each state's variability limit for a given control period 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 will 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 historical 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 is 130 percent of the historical heat input used in computing the state's 2025 budget, then the state's variability limit for the 2025 control period will be 30 percent of the state's emissions budget instead of 21 percent of the state's emissions budget. The EPA expects that the minimum 21 percent will apply in almost all instances, and that the alternative, higher percentage value will apply only in control periods where operational variability causes an unusually large increase relative to the historical data used in setting the state's emissions budget, which would be a situation meriting a temporarily higher variability limit and assurance level. The revised methodology for determining the variability limits will apply both with respect to control periods when a state's emissions budget is a preset budget established in this final rule and with respect to control periods when a state's emissions budget is a dynamically-determined budget computed using the procedures laid out in the regulations, and it will apply starting with the 2023 control period rather than starting with the 2025 control period as proposed.

The purpose of the revision to the variability limits is to better align the variability limits for successive control periods with the heat input data used in setting the state emissions budgets. Under the final rule, each dynamically

[319] 531 F.3d at 908.

[320] As discussed in section VI.B.8, the EPA is also establishing a new secondary emissions limitation for individual units that will apply in situations where an exceedance of the relevant state's assurance level has occurred.

[321] *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.

determined emissions budget will be computed using the latest available reported heat input, which for each budget set for a control period in 2026 or a later year will be the average state-level heat input for the control periods two, three, and four years before the control period whose budget is being determined (for example, the dynamic state emissions budgets for the 2026 control period will be computed in early 2025 using the reported state-level heat input for the 2022–2024 control periods). The revised variability limits will 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 multi-year average heat input used in computing the state's emissions budget will 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 is thus entirely consistent with the overall purpose of including variability limits in the assurance provisions.

As discussed in sections VI.B.1.b.i and VI.B.4, for the 2023–2025 control periods the state emissions budget for a given control period will be the preset budget determined in this rule, and for the 2026–2029 control periods, the state emissions budget for a given control period will be the preset budget determined in this rule rather than the dynamically determined budget computed in the year before the control period unless the dynamic budget is higher than the preset budget. If the state emissions budget is the preset budget, the historical heat input data reflected in that budget will be the heat input data for the 2021 control period, adjusted to reflect projected changes in fleet composition over time that are known at the time of this rulemaking, but not adjusted to reflect changes in fleet composition that are not known at the time of the rulemaking or changes in the utilization of individual units.[322] In this case, the variability limit for the control period would be the higher of 21 percent or the percentage change in the actual heat input for the control period relative to the heat input for the 2021 control period as adjusted to reflect the projected changes in fleet composition. The EPA believes it is reasonable to apply the same principle in setting the variability limit in control periods where the preset floor budgets are used as in control periods where the dynamically determined budgets are used, because the preset floor budgets are computed using the same principles as the dynamically determined budgets, with the major difference being that the available heat input data used in computing the preset budgets are necessarily less current. Accordingly, because preset budgets established in this manner are used starting with the 2023 control period, the EPA believes it is also reasonable to begin implementing the revised methodology for determining variability limits starting with the 2023 control period.

The reason the EPA is using the higher of a fixed 21 percent 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 revision will have the consequence that the state's final variability limit and assurance level for the control period also will not be known until after the control period. However, because the rule provides that the variability limit will always be at least 21 percent, the sources in a state will be able to rely for planning purposes on the knowledge that the assurance level will 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 fleet owner 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 the emissions from its fleet to exceed the fleet's aggregated share of the state's assurance level for the control period. Knowing that the variability limit will always be at least 21 percent will provide sources with minimum values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the minimum variability limit. 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 97.810, along with the respective state budgets.[323] 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.[324] 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 a higher percentage for the covered state with the smallest total heat input figures in this analysis—New Jersey—the EPA does not consider it appropriate to raise the minimum variability limit percentage beyond 21 percent for all other covered states based on the analytic results for one state, where small absolute heat input figures have resulted in a larger variability percentage.[325] (Moreover, because of the provision allowing a state's variability limit for a given control period to be higher than 21 percent if the state's actual heat input exceeds the heat input used to set the state's emissions budget by more than 21 percent, there is no need to set a minimum variability limit higher than 21 percent specifically for New Jersey.) Based on the consistent conclusions of these multiple analyses, the EPA is continuing to use 21 percent as the

[322] The total heat input amount used in computing each state's preset emissions budget for each control period from 2023 through 2029 is included in Appendix A of the Ozone Transport Policy Analysis Final Rule TSD at column I of the ''State 2023''–''State 2029'' worksheets.

[323] Briefly, the 21 percent variability limit was determined in the analysis by identifying, for all the states in the region covered by the ozone season NO_X trading program, and at a 95 percent confidence level, the maximum expected deviation in any state's total heat input for any single control period in the data sample from that state's trend-adjusted mean total heat input for all the control periods in the data sample. 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), available in the docket for this rule.

[324] 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'', available in the docket for this rule.

[325] *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.

minimum value in the revised approach for establishing variability limits for all control periods under this rule.

The provisions of the final rule relating to assurance levels and variability limits are unchanged from proposal, with the exception that the provision establishing a higher variability limit for a state in a given control period where the state's actual heat input exceeds the heat input used in computing the state emissions budget for that control period by more than 21 percent will be implemented starting with the 2023 control period instead of the 2025 control period.

Comment: Some commenters supported the EPA's proposal to raise a state's variability limit above 21 percent for a given control period if the state's actual heat input for the control period was more than 121 percent of the historical heat input used to set the state's budget for that control period. These commenters agreed with the EPA that making this adjustment is consistent with the assurance provisions' purpose of strongly incentivizing each state to achieve its required emissions reductions within the state while also accounting for year-to-year variability in electric system operations.

One commenter stated that the EPA should not finalize the proposed revision to the variability limit provisions, claiming that by allowing sources in some states to increase utilization and heat input so as to exceed the state's budget by more than 21 percent in a given year, the adjustment would then cause the state's subsequent dynamically determined budgets to be higher, allowing greater emissions over time.

Response: The EPA disagrees with the comment advocating against finalization of the proposed change to the variability limit provisions. The Agency continues to view the proposed change as useful for accommodating instances where, because of electrical system operating needs, a state's actual total heat input in a control period exceeds the historical heat input used to set the state emissions budget for the control period, potentially causing increased emissions even when all EGUs in a state are achieving emissions rates consistent with the Step 3 emissions control stringency. Moreover, the EPA does not believe that the provision would lead to higher overall program-wide budgets. No extra allowances would be created by the increase in a state's variability limit, so with or without the adjustment, any allowances to cover the emissions in excess of the state's budget would still need to be obtained through acquisition of allowances issued to sources in other states or the use of banked allowances. Thus, to the extent that the change in the variability limit provisions facilitates shifting of generation from some states to other states, increased heat input in the first set of states would generally be offset by decreased heat input in the second set of states, such that any increases in future dynamic budgets for the first set of states would be offset by decreases in future dynamic budgets for the second set of states. In addition, the final rule's use of multiple years of historical heat input data to compute the dynamically-determined state budgets will moderate the effect of any single year's heat input on the dynamically-determined budgets for future control periods.

6. Annual Recalibration of Allowance Bank

As discussed in section VI.B.1.b of this document, the EPA is making two revisions to the Group 3 trading program designed to better maintain the Step 3 emissions control stringency over time. The first proposed revision, discussed in section VI.B.4 of this document, is to adopt a dynamic budget-setting methodology that will allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, revision is to recalibrate the bank of unused allowances each control period to prevent allowance surpluses from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the Step 3 emissions control stringency.

As proposed and now finalized in this rule, the bank recalibration process will start 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 has been completed. The recalibration process for each control period will 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 date of the first recalibration August 1, 2024. The recalibrations take place on 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 will be known shortly after the end of that control period, sources and other market participants will 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. The EPA will make an estimate of the applicable calibration ratio for each control period publicly available no later than March 1 of the year of the control period for which the bank will be recalibrated.

Before undertaking a recalibration process each control period, the EPA will 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 exceeds the target bank amount. (For this purpose, no distinction will 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 will not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA will determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the account's total holdings of banked Group 3 allowances immediately before the recalibration multiplied by the target bank amount and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA will 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 will use an amount determined as a percentage of the sum of the state emissions budgets for the control period. For the control periods from 2024 through 2029, the target percentage will be 21 percent, which is the sum of the states' minimum variability limits.[326] For control periods in 2030 and later years, the target percentage will be 10.5 percent, or half of the sum of the states' minimum

[326] As discussed in section VI.B.5, an individual state's variability limit can be higher than 21 percent in a given control period if the state's actual heat input for that control period is more than 121 percent of the historical heat input used in computing the state emissions budget for the control period.

variability limits. In the proposal, the EPA cited two reasons for proposing the 10.5 percentage 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 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 percent confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the minimum variability limit of 21 percent for the states in the trading program.[327] 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 reasonable 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.

In the final rule, in response to comments, the EPA has determined to maintain the 10.5 target percentage for the reasons discussed in previous paragraphs, but to defer application of this target percentage until the 2030 control period. For the control periods from 2024 through 2029, the EPA will instead use a target percentage of 21 percent. The reason for using a higher target percentage for the 2024–2029 control periods is to provide additional support for allowance market liquidity during these years, which both the EPA and commenters view as an important period of generating fleet transition for the power industry.

The annual bank recalibrations, at either ratio, are an important enhancement to the trading program that will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS over time. Moreover, the 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. As a consequence of this uncertainty, in some control periods, allowances banked from earlier control periods traded at lower prices than allowances issued for the current control period.[328] The EPA considers the recalibration mechanism established in this rule to be simpler with less associated uncertainty. Following each bank recalibration, all allowances usable for compliance in the control period will have known, equal compliance values for the remainder of the control period and until the deadline for surrendering allowances after the control period.

Finally, the EPA observes that the 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 is determining 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 recalibration process will complement the revised budget-setting process by preventing 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. For further discussion of the reasons for bank recalibration, see section VI.B.1.b.ii of this document.

The bank recalibration mechanism finalized in this rule is unchanged from the proposal except for the final rule's adoption of a target percentage of 21 percent rather than 10.5 percent for the control periods from 2024 through 2029. The EPA's responses to comments on the bank recalibration mechanism are discussed in the remainder or this section and in section 5 of the *RTC* document. Further discussion of the reasons for adopting a higher target percentage for the 2024–2029 control periods is included in section VI.B.1.d of this document.

Comment: Some commenters acknowledged the EPA's authority to manage the quantities of allowances carried over from one control period to the next as banked allowances, including some commenters who as a policy matter did not support such an approach. Other commenters claimed that any removal from the program of allowances banked in earlier control periods would constitute an unlawful taking of property or would constitute unlawful overcontrol.

Response: The EPA disagrees with comments contending that the proposed bank recalibration provisions would be unlawful, either as asserted takings of property or as over-control for purposes of the Good Neighbor provision. With respect to the claim that removing allowances would constitute takings of property, the commenters misconstrue the nature of an allowance. The allowances used in the Group 3 trading program are created under the program's regulations, which expressly provide that the allowances are not property rights but are limited authorizations to emit NO_X in accordance with the provisions of the Group 3 trading program.[329] These provisions of the Group 3 trading program regulations have been in existence since the Revised CSAPR Update and were not reopened in this action. This approach of creating limited authorizations to engage in particular forms of conduct within a regulatory program extends back to the Acid Rain Program, where the approach was mandated by Congress, and has been followed by EPA in each subsequent allowance trading program for the electric power sector.[330] Moreover, as noted earlier in this section, the Group 3 trading program regulations provide the EPA

[327] 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.

[328] For more discussion of the progressive flow control mechanism, as well as allowance price data showing a discounted value for banked allowances, see ''NO_X Budget Trading Program: 2005 Program Compliance and Environmental Results'' (September 2006) at 28–30, *https://www.epa.gov/sites/default/files/2015-08/documents/2005-nbp-compliance-report.pdf.*

[329] 40 CFR 97.1006(c)(6)–(7).

[330] *See, e.g.,* 42 U.S.C. 7651b(f) and 40 CFR 72.9(c)(6)–(7) (Acid Rain Program example); 40 CFR 97.6(c)(6)–(7) (Federal NO_X Budget Trading Program example); 40 CFR 97.106(c)(5)–(6) (CAIR NO_X Annual Trading Program example).

Administrator with the 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, and the Administrator is making such a determination in this rule.

The EPA also disagrees that bank recalibration would constitute overcontrol. The emissions that are permissible in a given control period consistent with the Step 3 control stringency are quantified in the state emissions budgets for the control period. Banked allowances from previous control periods are necessarily surplus to the state emissions budgets for the current control period. As noted in section VI.B.1, in an allowance trading program, banking provisions can serve several useful purposes, including 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. However, these useful purposes do *not* include allowing sources to plan to emit in excess of the Step 3 control stringency as represented by the state emissions budgets for the control period. Accordingly, in the overcontrol analysis discussed in section V.D.4, the EPA analyzed whether the emissions reductions necessary to meet the state emissions budgets without relying for compliance purposes on any allowances banked in earlier control periods would result in overcontrol and determined there would be no overcontrol. (That is, the modeling of the effects of the Group 3 emissions budgets in 2026 did not include an assumption that there would be any banked allowances.) Thus, even if the Agency had finalized regulatory provisions removing *all* banked allowances from the trading program between control periods—in contrast to the actual bank recalibration provisions, which permit substantial quantities of banked allowances to remain in the trading program—the information available to the Agency suggests such provisions would not constitute over-control. With respect to some commenters' assertions that bank recalibration would over-control by ''writing off'' emission reductions that may have gone beyond the reductions necessary to address the Good Neighbor provision or would make it more difficult to create surplus allowances in one control period to offset excess emissions in later control periods, EPA notes that the NAAQS apply continuously, and the possibility that the sources in a state may have done more than the minimum necessary to meet the state's Good Neighbor obligations in one control period does not create a right for the state to do less than is necessary to meet the state's Good Neighbor obligations in subsequent control periods.

Comment: Some commenters expressed concern that excessive quantities of banked allowances, like excessive quantities of budgeted allowances, can lead to lower allowance prices. The commenters observed that with lower allowance prices, some units would likely operate their controls less effectively, resulting in a greater likelihood that the emissions stringency found necessary in this rule would not be sustained. Other commenters expressed the view that other provisions of the rule, including more stringent state emissions budgets, the backstop daily NO_X emissions rate provisions, and the assurance provisions would be sufficient to incentivize EGUs to operate their controls effectively, making allowance bank recalibration superfluous for this purpose.

Response: The EPA agrees with the comments explaining that without bank recalibration, the quantities of banked allowances can grow, leading to lower allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency, and disagrees with the comments arguing that other rule provisions would make bank recalibration unnecessary. The suggestion that the assurance provisions can maintain program stringency regardless of allowance quantities ignores the fact that the emission levels consistent with the Group 3 control stringency in a given control period are the state emissions budgets, not the higher assurance levels. If the quantities of banked allowances in the program grow to the point where sources collectively can plan to emit above the collective state emissions budgets, then the trading program would be unable to ensure that the Group 3 control stringency is being achieved, even if emissions do not rise further than the assurance levels. Further, there are now examples from the Group 2 trading program of sources emitting in excess of the state-wide assurance levels, because a glut of banked allowances which was not prevented by the regulations for that trading program rendered even the three-to-one surrender ratio ineffective. Suggestions that the backstop emissions rate provisions can maintain program stringency regardless of the quantities of banked allowances are similarly mistaken, because rather than reducing overall emissions of all sources in the trading program, the backstop rate provisions are designed to ensure that the largest individual sources of potential emissions operate their controls consistently. If the quantities of banked allowances are allowed to grow to the point where sources collectively can plan to emit above the collective state emissions budgets, the backstop rate provisions would do nothing to constrain emissions from the sources not subject to the backstop rate.

With respect to the suggestion that state emissions budgets reflecting sufficient control stringency can avoid the need for bank recalibration, the EPA observes that the budget-setting and bank recalibration provisions in this rule are complements, not substitutes. If in a given year sources collectively emit against the collective state emissions budgets such that the ending allowance bank—that is, the allowances remaining after deduction of the allowances required for compliance—is less than the bank target amount, then the bank will not be recalibrated for the following control period. However, in the event that sources collectively emit against the collective state emissions budgets such that the ending allowance bank is above the bank target amount, then the recalibration provisions will ensure that the recalibrated allowance bank does not introduce an excessive overall quantity of allowances into the trading program for the following control period when combined with the state emissions budgets calculated for that control period. Without the recalibration provisions, the trading program would lack any mechanism for removing excess allowances that are inconsistent with maintaining the Step 3 emissions control stringency which the Step 4 trading program is designed to implement.

Comment: Some commenters claimed that the recalibration process itself would have undesirable consequences. First, some said that because bank recalibration would be executed partway through the control period, it would introduce uncertainty concerning the quantities of allowances each source would have available, impeding efforts to plan. Second, some commenters claimed that the prospect of bank recalibration would create counterproductive incentives for allowance holders. According to the commenters, allowances holders would be incentivized to ''use or lose'' their allowances (to reduce the number of allowances that would be removed from their accounts in the recalibration process), thereby causing increased emissions, or alternatively would be incentivized to refuse to sell allowances (to allow the holders to have more allowances after the next recalibration), thereby reducing allowance market liquidity.

Response: The EPA disagrees with these comments. As discussed previously in this section, the recalibration process has been scheduled for August 1 of each control period because compliance for the previous control period (and the associated allowance trading activities) would not be completed until after June 1. However, the information needed to project the degree of recalibration will be available by early November of the previous year, and the EPA will make an estimate publicly available no later than March 1, two months before the start of the control period. Further, at least 80 percent of the allowances for use in a given control period will be the allowances allocated from the state emissions budgets (with the recalibrated banked allowances from the prior control period comprising the remainder), and the emissions budgets and unit-level allocations amounts will be known approximately a year before the start of the control period.

The comments claiming that the introduction of a bank recalibration process would create incentives to ''use or lose'' allowances or to hoard allowances are not persuasive. By reducing the supply of allowances carried over from previous control periods, bank recalibration would tend to raise the price of allowances in the current control period, making it more cost-effective and therefore in sources' interest to further reduce their emissions than to increase their emissions. Higher allowance prices would also increase the cost of hoarding allowances just as higher fuel prices raise the cost of maintaining large fuel inventories. Moreover, the EPA expects that the prospect of having banked allowances recalibrated after the end of the control period is much more likely to *discourage* hoarding than to encourage it. Given the choice between holding an allowance which may be removed as part of an upcoming recalibration process or instead selling the allowance for cash, the sale option will become more attractive. By creating a ''sell or lose'' incentive for holders of surplus allowances, the recalibration process should increase allowance market liquidity. At the same time, by ensuring a banked allowance will always have some value for use in a future control period, the bank recalibration mechanism in this program will continue to incentivize early emissions reductions.

Comment: Turning to the level of the bank recalibration target, some commenters objected to the target bank percentage of 10.5 percent, saying that a larger bank would be needed to ensure that sufficient allowances would be available to enable sources to run as needed to provide reliable electricity service, particularly with the large year-to-year swings in budgets that the commenters anticipated could occur with dynamic budgets computed using a single rolling historical year and with anticipated growth in renewable generation. Some commenters recommended a target bank percentage of 21 percent. Some commenters stated that even if the overall quantity of allowances available for use was greater than the total amount of emissions, a larger bank of allowances would facilitate trading and promote greater allowance market liquidity, citing reports of high allowance prices in 2022.

Response: As discussed in sections VI.B.1.d and VI.B.4 and earlier in this section, the EPA does not agree with comments suggesting that annual bank recalibration in itself poses a risk to electric grid reliability. Nevertheless, the Agency has made several changes from proposal in the final rule designed to address concerns expressed about reliability by increasing compliance flexibility through the 2029 control period. These changes through the 2029 control period include the use of a target bank percentage of 21 percent and the promulgation of preset budgets that will serve as the state emissions budgets unless the dynamic budgets for the control periods are higher. In addition, to reduce year-to-year variability under the budget-setting methodology, dynamic budgets will be calculated using multiple years of historical heat input data instead of heat input data from a single year. The EPA views these changes as responsive to the principal reasons that commenters gave for their claims that the target bank percentage should be higher than 10.5 percent. Regarding the claim that a higher target bank percentage is needed because increased renewable generation makes the demand for fossil generation more variable, commenters did not provide evidence demonstrating that the overall quantities of fossil generation throughout the multi-state region covered by this rule—as opposed to the operating patterns of some individual units—are becoming more variable, and the Agency declines to make an adjustment for such a reason at this time.

With respect to the comments advocating for an even higher bank target percentage to facilitate trading and promote market liquidity, the Agency observes that any such advantage of larger allowance banks must be balanced with the disadvantages of excess allowance supply—specifically, reduced allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency. In the final rule, the EPA finds that a reasonable balance between these opposing considerations is struck by temporarily adopting a higher bank target percentage of 21 percent (consistent with the initial bank targets used in this rule and previous rules) and deferring implementation of the 10.5 percent target bank percentage identified by the Agency's analysis as a sustainable percentage in the longer term until the 2030 control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in section V of this document (*i.e.,* the Step 3 emissions control stringency) 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 a backstop daily emissions rate of 0.14 lb/mmBtu applied to coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states, except circulating fluidized bed units. This is important for ensuring the elimination of significant contribution on a more consistent basis from the relevant sources and over each day of the ozone season.

Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls (except circulating fluidized bed units) starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. See Appendix A of the Ozone Transport Policy Analysis Final 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 will apply.

For each unit subject to the backstop daily emissions rate provisions for a given control period, the amount of emissions subject to the 3-for-1 surrender ratio will be determined as follows, generally on an automated basis using the unit's data acquisition and handling system (DAHS) required under 40 CFR part 75. For each day of the control period where the unit's average emissions rate for that day was higher than 0.14 lb/mmBtu, the owner or operator will compute what the unit's reported emissions on that day would have been (given the unit's reported heat input for the day) at an emissions rate of 0.14 lb/mmBtu. The difference between the unit's emissions for the day as actually reported and the emissions that would have been reported if the unit's emissions rate was 0.14 lb/mmBtu is the unit's daily exceedance. The amount of emissions subject to the 3-for-1 surrender ratio for the control period is the sum of the unit's daily exceedances for all days of the control period minus 50 tons (but not less than zero).[331] All calculations will rely on the data monitored and reported for the unit in accordance with 40 CFR part 75.

The EGU NO_X Mitigation Strategies Final 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 stakeholders' focus on providing daily assurance of control operation, which is consistent with the 8-hour form of the 2015 ozone NAAQS and the tendency for ozone levels to spike on a diurnal cycle, the 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.[332] 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. This seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions. 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.[333] 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 equivalent to a 30-day rate of 0.08 lb/mmBtu for purposes of this comparison of rates across averaging times) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu).

The inclusion of a 50-ton threshold for emissions exceeding the backstop daily emissions rate before the 3-for-1 surrender applies is a change from the proposal. As discussed in section VI.B.1.d of this document, the EPA made this change in response to comments concerning the possibility that the 3-for-1 surrender ratio could otherwise have applied to emissions outside an EGU operator's control, with the most important example being the emissions during unit startup before SCR equipment can be brought into service, and to a lesser extent the emissions during unit shutdown. The analysis used by the EPA to derive the 50-ton threshold is described in detail in the Ozone Transport Policy Analysis Final Rule TSD. Briefly, for a set of 164 SCR-equipped units with seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu in 2021, the EPA evaluated the total amounts of emissions that would have been determined to exceed a daily average emissions rate of 0.14 lb/mmBtu in the 2021 and 2022 ozone seasons. In the 2021 ozone season, only 572 tons out of these units' total emissions of 60,350 tons, or 0.9 percent, would have been considered exceedances, with an average exceedance per unit of less than 4 tons. The highest amount for any of the 164 individual units in either ozone season was 48 tons. Based on this analysis, the EPA concludes that adding a 50-ton threshold to the backstop daily emissions rate provisions will ensure that substantially all emissions outside the control of an SCR-equipped unit's operator will not be subject to the 3-for-1 surrender ratio. Because there is no reason to expect the range of emissions during conditions when SCR controls cannot be operated to differ between SCR-equipped units and units without SCR, inclusion of the 50-ton threshold effectively prevents application of the 3-for-1 ratio to emissions during startup and shutdown by units without SCR as well.

At the same time, the EPA believes the 50-ton threshold is not large enough to eliminate the intended incentive to achieve emissions rates consistent with good SCR performance under conditions other than startup and shutdown. For a set of 124 SCR-equipped units with seasonal average NO_X emissions rates above 0.08 lb/mmBtu, the total amount of emissions exceeding a daily average emissions rate of 0.14 lb/mmBtu in the 2021 ozone season was 18,629 tons. Of this total amount, 15,374 tons would have been in excess of the 50-ton thresholds for the various units, indicating that even after application of the threshold, the 3-for-1 surrender ratio would have applied to over 80 percent of the daily exceedance amounts.

The backstop daily NO_X emissions rate provisions finalized in this rule are unchanged from the proposal except for the inclusion of a 50-ton threshold for emissions exceeding the backstop emissions rate before the 3-for-1 surrender ratio applies and the deferral of the application of the provisions to units without existing SCR controls

[331] In the regulatory text at 40 CFR 97.1024 defining the total quantity of allowances that must be surrendered for a source's emissions in a control period, these amounts of emissions for all the units at the source are subject to a requirement to surrender two extra allowances per ton in addition to the usual 1-for-1 allowance surrender requirement, yielding a total surrender ratio of 3-for-1 for emissions over the 50-ton threshold.

[332] *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.''

[333] *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.*

until the 2030 control period or, if earlier, the second control period in which new SCR controls are operated at a unit. The EPA's responses to comments on the backstop daily NO_X emissions rate provisions, including the reasons for these changes, are discussed in the remainder of this section and in section 5 of the *RTC* document.

Comment: Some commenters strongly supported the backstop daily emissions rate provisions, noting their benefit to downwind receptors on potential nonattainment days, their benefit to neighboring communities, and evidence of deterioration in SCR performance in the absence of such provisions. Other commenters stated that the backstop daily emissions rate provisions are unnecessary, either because SCR-equipped EGUs would already be sufficiently incentivized to operate and optimize their controls by the stringency of the state emissions budgets and the resulting allowance prices or because most SCR-equipped EGUs are already required to operate and optimize their SCRs by conditions in their operating permits. Some commenters cited previous EPA analyses showing that it is unusual for SCR-equipped units to turn off their SCRs only on high electricity demand days (HEDD).

Commenters suggested diverse possible changes to the types of EGUs that would be covered by the backstop daily emissions rate provisions. Some commenters stated that the provisions should apply to all EGUs or to all SCR-equipped EGUs, including non-coal-fired units. Other commenters stated that exemptions should be provided for units operating at capacity factors below 10 percent or for emissions during emergencies.

Some commenters stated that implementation of the backstop daily emissions rate provisions would cause unintended and counterproductive consequences. Some of these commenters claimed that by requiring the surrender of extra allowances, the backstop emissions rate provisions would create shortages of allowances for the program overall. Other commenters claimed that the disincentives to operate units subject to the backstop emissions rate provisions would cause load to shift to higher-emitting generators not covered by the trading program (such as sources in states outside the program's geographic region, EGUs smaller than 25 MW, and sources considered demand-side resources, including end-user-sited diesel generator units), potentially resulting in higher overall emissions.

Response: The EPA agrees that backstop daily emissions rate provisions should be implemented and disagrees with comments suggesting that the need for the backstop daily emissions rate provisions is contradicted by previous EPA analyses or is already adequately addressed by other provisions of this rule or other legal requirements. As discussed in sections V.D.1 and VI.B.1.c of this document, the EPA has determined that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate. There are several important differences between this rule and previous actions addressing interstate ozone transport where the Agency did not include such provisions. First, this rule constitutes a full remedy, unlike some prior actions. Second, this rule is the first rule in which the EPA is addressing good neighbor obligations with respect to the more protective 2015 ozone NAAQS. Third, the EPA has examined the most recent data over a broader geographic and temporal footprint specific to the coverage of this rule, and it illustrates a greater degree of SCR performance erosion than in the prior years in which EPA conducted such analysis. Fourth, nonattainment and maintenance for this NAAQS are projected to persist well into the future in EPA's baseline, making enhancements and safeguards such as the backstop daily emissions rate provisions essential for securing elimination of significant contribution in future periods for which fleet configuration is inherently more uncertain.

With respect to claims that inclusion of the backstop daily emissions rate provisions is contradicted by the EPA's earlier analyses concerning SCR operational changes specific to high electricity demand days, the EPA disagrees. Historical data reported to the EPA show that multiple SCR-equipped units across the states covered by this action have chosen not to operate their SCRs, or to operate them at materially less than their full removal capability, for entire ozone seasons. The apparent infrequency of one type of behavior—*i.e.,* instances of units running their controls on most days but turning the controls off specifically on high electricity demand days—does not contradict the evidence concerning another type of behavior—*i.e.,* non-operation or suboptimal operation of controls for entire ozone seasons. The evidence from previous trading programs demonstrates that reliance solely on the incentives created by allowance prices and corresponding static state emissions budgets has been insufficient to cause all SCR-equipped units to operate and optimize their controls for entire ozone seasons.

The EPA acknowledges that some SCR-equipped units are likely already subject to other legal requirements calling for their SCR controls to be operated and optimized such that their seasonal average NO_X emissions rates will generally not exceed 0.08 lb/mmBtu (the level of seasonal SCR performance that the EPA used to derive the equivalent 0.14 lb/mmBtu level of daily SCR performance for the backstop daily NO_X emissions rate). However, commenters do not claim, and the EPA does not believe, that *all* SCR-equipped units are subject to other legal requirements calling for an equivalent degree of SCR operation and optimization. In the context of a multi-state trading program, it is more efficient and equitable, and far more transparent, for the EPA to establish rule provisions uniformly incentivizing all large coal-fired EGUs to install and operate SCR controls than to attempt to establish differentiated requirements for various units according to the EPA's analysis of the effectiveness of their pre-existing permit conditions. Further, to the extent that a given unit's permits already require SCR performance that would meet the backstop emissions rate established in this rule, or to the extent that allowance prices would incentivize the unit to operate the SCR anyway, the EPA expects that the backstop daily emissions rate provisions (as finalized with a 50-ton threshold to address emissions outside an EGU's control before the 3-for-1 surrender ratio applies) will cause no incremental cost for the unit.

The EPA disagrees with the suggested changes to applicability of the backstop emissions rate provisions. With respect to the comments advocating broader coverage, the EPA discusses its reasons for applying the provisions only to coal-fired EGUs in section VI.B.1.c of this document, including the fact that operation of SCR controls is a well-established practice among the best performing coal-fired boilers but not for non-coal-fired units.[334] The comments indicate a preference for a less flexible trading program design than the EPA has found appropriate but do not demonstrate that EPA's decision to allow greater flexibility is either impermissible or unreasonable; our reasoning in this regard is further explained in section VI.B.1.c.i of this

[334] Nationwide and among operating units in 2021, EPA identified the best performing quartile (*i.e.,* lowest ozone season emissions rate) of coal-fired EGU boilers (excluding CFB units). Nearly 100 percent of these units (159 of 160 units) were equipped with SCR controls.

document. With respect to the comments advocating narrower coverage, the commenters have provided no information indicating that the sources for which exemptions are sought could not comply with the provisions, including through the surrender of additional allowances if necessary. The EPA notes that emissions from coal-fired units operating at low capacity factors may be concentrated around days of high electricity demand when incentives to minimize such emissions may be most helpful in mitigating downwind air quality problems. The EPA also notes that to the extent the comments are intended to support exemptions for units without existing SCR controls, the final rule defers application of the backstop emissions rate provisions to such units until the 2030 control period, providing additional flexibility to develop alternatives to the use of such units if the owners choose not to equip them with SCR controls.

Finally, the EPA also disagrees with the comments asserting that the backstop emissions rate provisions would cause unintended and counterproductive consequences. With respect to units already equipped with SCR controls, the EPA expects that by far the most important effect of the provisions will be to incentivize the units to operate and optimize their controls. The EPA sees no basis for speculation that such units would choose to operate in a manner that would result in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio or in generation being shifted to sources outside the trading program. The results of the EPA's modeling of benefits and costs of the rule show little leakage of emissions to non-covered sources, and commenters have presented no analysis to the contrary. For instance, as shown in Table 4.6 of the *RIA,* non-covered state ozone season NO_X emissions increased on average by 1 percent over the 2023–2030 time period between the base and final rule scenarios, while covered state emissions fell by 14 percent on average over the same period. With respect to units without existing SCR controls, the EPA expects the backstop emissions rate provisions, when they would take effect for such units, to provide a strong incentive against extensive operation (unless and until such controls are installed), again not resulting in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio.

Comment: For units with existing SCR controls, the aspect of the backstop daily emissions rate provisions that received the most attention in comments was how emissions outside the operator's control should be treated. Multiple commenters expressed concern that the backstop daily emissions rate would be exceeded on days when the SCR equipment cannot be operated for all or a portion of the day. The most commonly cited example of a situation where SCR equipment cannot be operated was unit startups, although some commenters also mentioned unit shutdowns, boiler or emissions control malfunctions, and unit maintenance or tests. The commenters expressed the view that emissions that cannot be controlled by SCR equipment should be exempted from the backstop emissions rate provisions and suggested a variety of approaches for implementing an exemption.

Some commenters also stated that the backstop emissions rate provisions would not sufficiently accommodate sustained low-load operation, such as where an SCR-equipped unit operates for extended periods at a load level too low to permit SCR operation so that the unit is ready to ramp up to higher load levels in less time than would be required for a startup. The commenters suggested that implementation of a backstop daily rate would reduce the ability to operate the units in this manner, generally reducing system flexibility. Some noted that the need for flexibility of this nature is increasing because of the rapid growth in intermittent renewable generation.

Additional comments on the backstop daily emissions rate provisions for units with existing SCR controls addressed the level of the daily emissions rate and the implementation timing. With respect to the rate level, various commenters suggested rates from 0.08 to 0.20 lb/mmBtu. With respect to implementation timing, some commenters stated that because immediate compliance was possible, the good neighbor provision required implementation as of the 2023 control period rather than the 2024 control period as proposed. Other commenters expressed the view that units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls. Some owners of SCR-equipped EGUs that exhaust to stacks shared with EGUs without SCR suggested that their particular units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls in order to avoid the cost of upgrading their emissions monitoring equipment.

Response: With respect to the topic of emissions outside an operator's control, as a general matter the EPA agrees that the backstop daily emissions rate provisions are intended to incentivize good SCR operation and that it was not the Agency's intent to apply a higher surrender ratio to emissions that are truly unavoidable, such as emissions occurring before an operator could reasonably initialize SCR operation when a unit is started up. As explained elsewhere in this section, the EPA selected the level of the backstop rate based on analysis of 2021 emissions data showing that for SCR-equipped coal-fired units achieving seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu, more than 99 percent of the units' emissions would fall below a backstop daily emissions rate of 0.14 lb/mmBtu. In response to the comments summarized previously, the EPA has further analyzed 2021 and 2022 emissions data to determine what if any modifications to the proposal might be appropriate to limit the imposition of a 3-to-1 allowance surrender requirement for emissions caused by circumstances outside an operator's control while preserving the intended incentive to operate and optimize SCR controls whenever possible. The analysis showed that for the same set of units achieving seasonal average emissions rates at or below 0.08 lb/mmBtu, the highest total amount of emissions exceeding the backstop daily emissions rate in either the 2021 or 2022 control period for any unit was 48 tons. The Agency views this amount as a reasonable upper bound on the quantity of emissions that might contribute to an exceedance of the backstop emissions rate arising from circumstances outside an operator's control for any coal-fired unit, not just the well-controlled units in the data set analyzed, because the amount generally encompasses all of a unit's emissions occurring in hours when an SCR could not be operated over an ozone season.

Based on this analysis, the backstop daily emissions rate provisions in this final rule exclude the first 50 tons of a unit's emissions in a given control period exceeding the backstop daily emissions rate from incremental allowance surrender requirements. The EPA finds that establishing a threshold of this nature will provide an appropriate maximum exclusion to all coal-fired units for unavoidable emissions caused by circumstances outside the operator's control while maintaining the incentives for less well-controlled units to improve their emissions performance on all days of the ozone season. Well-controlled units will likely have no emissions over the threshold that will be subject to incremental allowance surrender requirements, while for SCR-equipped units not already achieving a seasonal average emissions rates sufficiently low to routinely operate at daily average emissions rates of 0.14 lb/mmBtu or less, the incentive to reduce daily emissions rates will remain in place, because the 50-ton threshold is not expected to encompass all emissions exceeding the backstop daily emissions rate for such units. In contrast to more complicated exceptions suggested by commenters, the 50-ton threshold can be easily integrated into the overall trading program structure with minimal additional recordkeeping and reporting requirements.

With respect to the comments claiming that the inability of some SCR-equipped units to operate their SCR controls at sustained low load levels likewise merits alteration of the backstop daily emissions rate provisions, the EPA disagrees. There is no dispute concerning the technical need for a unit to attain and maintain a certain range of exhaust gas temperatures at the SCR inlet in order to achieve optimal SCR performance and no dispute concerning the general relationship between a unit's load level in a given hour and its ability to attain and maintain that exhaust gas temperature range in that hour. However, the EPA is also aware that at least in some cases, units whose role in the integrated electric system currently calls for them to operate at low load levels for sustained periods (such as overnight) in fact may be able to operate at slightly higher load levels that would accommodate SCR operation during those periods and still meet the needs of the integrated electric system, thereby avoiding operation of the unit for sustained periods with the SCR out of service. Figure B.5 in the EGU NO_X Mitigation Strategies Final Rule TSD illustrates this opportunity using data reported for the 2021 and 2022 ozone seasons by a large SCR-equipped EGU in Pennsylvania. In both ozone seasons, the unit often cycled daily between its maximum load of approximately 900 MW during the daytime and a lower load level overnight, and in both ozone seasons the unit's typical daytime emissions rate was between 0.05 and 0.07 lb/mmBtu. However, while in the 2021 ozone season, the unit cycled down to a load level of approximately 440 MW overnight and did not operate its SCR, in the 2022 ozone season, when allowance prices were considerably higher, the unit cycled down to a load level of approximately 540 MW overnight and did operate its SCR. Despite the higher nighttime generation levels, the result was a decrease of roughly 50 percent in the unit's seasonal average NO_X emissions rate, from approximately 0.14 lb/mmBtu to approximately 0.07 lb/mmBtu, and a comparable reduction in NO_X mass emissions. This unit is not uniquely situated; operating data for several other large SCR-equipped EGUs in Pennsylvania show the same past pattern of cycling down to low load levels at which the SCR controls cannot be operated, and these other units have similar opportunities to cycle down to somewhat higher load levels (necessarily subject to the needs and constraints of the integrated electric system) at which their SCR controls can be operated.[335] No commenter has submitted data to the contrary. Furthermore, this example demonstrates the need for this rule's backstop emissions rate provision, which (had it been in place) would have motivated this facility to operate its SCR overnight during the 2021 ozone season when the prevailing allowance price provided an insufficient incentive to do so.

The EPA disagrees with the comments advocating for a backstop daily emissions rate lower or higher than 0.14 lb/mmBtu. In general, these comments simply represent disagreements with the EPA's conclusions regarding the identification of required emissions reductions under this rule, as reflected in part by the EPA's conclusion that a seasonal average emissions rate of 0.08 lb/mmBtu reasonably reflects the seasonal average emissions rate achievable through optimization of controls by existing SCR-equipped units that are not already achieving a lower seasonal average emissions rate. Comments concerning the selection of the 0.08 lb/mmBtu seasonal average emissions rate are addressed in section V of this document. Commenters did not challenge the EPA's analysis identifying a daily emissions rate of 0.14 lb/mmBtu as comparable in stringency to a seasonal average emissions rate of 0.08 lb/mmBtu (see further discussion elsewhere in this section).

The EPA also disagrees with the comments stating that the backstop daily emissions rate provisions should apply to units with existing SCR controls starting in a control period earlier or later than the 2024 control period. The EPA does not consider implementation of the provisions in the 2023 control period feasible because it is currently unknown whether the necessary updates to the emissions recordkeeping and reporting software for all the affected sources could be completed and tested before July 30, 2023, which is the first quarterly reporting deadline for the 2023 control period. Moreover, as discussed in section VI.B.1.c.i of this document, implementing the requirements starting in 2024 will provide a window for EGUs to improve the consistency of SCR operation or in some cases to optionally install additional emissions monitoring equipment. As for the suggestion that implementation timing of the backstop daily emissions rate provisions for units with existing SCR controls should be synchronized with the later implementation timing for units without existing SCR controls, the EPA is not persuaded that there is any inequity in implementing provisions intended to incentivize operation of SCR controls first at sources that already have such controls and later at sources that do not already have such controls, allowing time for the latter sources to install the controls. In any event, in this instance, where some upwind sources have an immediate and highly cost-effective option for controlling their emissions, the statutory requirement for significant contribution to be eliminated as expeditiously as practicable so as to provide downwind states with the protection intended by the Good Neighbor provision overrides these sources' claim of inequity relative to sources whose emissions control options would take longer and have higher cost. We conclude that the backstop daily emissions rate is an important aspect of the elimination of significant contribution and should be applied at the relevant units. It is only out of recognition of unique circumstances associated with facilitating power-sector transition as identified by commenters, that we defer the application of the rate for the minority of units that have not yet installed SCR controls.

Finally, with respect to the SCR-equipped units that share common stacks with units that do not have SCR, the EPA disagrees that monitoring cost considerations merit a later implementation date for the backstop daily emissions rate provisions. As discussed in section VI.B.10 of this document, five plants with this configuration are covered by the rule (one of which has announced plans to retire in 2023). Under this rule, as proposed, the owner of a plant with this

[335] See the spreadsheet "Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data" in the docket.

configuration can choose between either upgrading the plant's monitoring systems so as to obtain unit-specific NO_X emissions rate data for each unit subject to the backstop daily emissions rate or else using the NO_X emissions rate data from the common stack, recognizing that the common stack emissions rate would generally be biased upwards relative to the emissions rate that could be reported for the SCR-equipped unit if that unit's emissions were monitored separately. Commenters have suggested a third option of a temporary exemption from the backstop emissions rate to avoid the cost of upgrading their monitoring systems. With the timing for implementation of the backstop emissions rate provisions for currently uncontrolled units in the proposal, the temporary exemption for the SCR-equipped units would have been in place for three control periods, from 2024 through 2026. With the final rule's deferral of the implementation of the backstop emissions rate provisions for the uncontrolled units for up to three years, the suggested temporary exemption for the SCR-equipped units would be in effect for up to six control periods, from 2024 through 2029. The EPA does not consider it reasonable to allow these SCR-equipped units an exemption from the backstop rate provisions for six years to avoid the cost of upgrading their monitoring systems, particularly given that the additional costs of monitoring at the individual-unit level are already borne by the large majority of other plants and the rule already provides these plants with an alternative to the monitoring system upgrades, if desired, by allowing the plants to use the emissions rate data from the common stack.[336]

Comment: With respect to units without existing SCRs, some commenters viewed the backstop daily emissions rate provisions as likely to make units without SCR altogether unwilling or unable to operate and characterized the provisions as a mandate for such units to install such controls or retire as of the control period when the provisions are implemented. Other commenters acknowledged that the provisions are not actually hard limits but stated that the higher allowance surrender ratio for emissions in excess of the backstop daily rate would nevertheless reduce the ability of such units to operate as needed to back up intermittent renewable generation. Some commenters claimed that inclusion of the backstop daily emissions rate provisions would substantially eliminate the potential benefits of allowance trading, because all units would have to meet the same emissions rate.

Some commenters stated that the proposed application of the daily backstop emissions rate provisions in the 2027 control period in some cases would occur only slightly before the units' otherwise planned retirement dates, and that short-term reliability considerations could create the need to make substantial investments in new controls at the units, which in turn could result in deferral of the units' retirement plans. In the proposal, the EPA requested comment on the possibility of deferring the application of the backstop emissions rate provisions to units without existing SCR controls until the 2029 control period if the owners provided the EPA with information indicating with sufficient certainty that the units would retire by the end of 2028. Commenters in favor of this concept suggested longer deferral periods, ranging from 2029 through 2032, and some also suggested that the EPA should simultaneously enlarge the emissions budgets to provide more allowances for units subject to the deferred requirement. Other commenters opposed any deferral of the applicability of the backstop rate provisions.

Response: The EPA disagrees that implementation of the backstop daily emissions rate provisions for EGUs without existing SCR controls constitutes a mandate for such units to install controls or retire but agrees that, as intended, the provisions would create strong incentives to minimize operation of the units unless and until controls are installed, and further agrees that in some instances retirement and replacement may be a more economically attractive option for the unit's customers and/or owners than installation of new controls. The EPA's rationale for determining at Step 3 that the control stringency required to address states' good neighbor obligations includes achievement of emissions rates consistent with good SCR performance at all large coal-fired EGUs (other than circulating fluidized bed boilers) is discussed in section V.D.1 of this document, and the EPA's rationale for determining at Step 4 that the trading program should include strong unit-level incentives to implement these controls is discussed in section VI.B.1.c. of this document. As noted in section VI.B.1.c of this document, the backstop daily emissions rate provisions are structured as incremental allowance surrender requirements rather than as directly enforceable emissions limits 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. The EPA appreciates that, in comparison to previous transport rules using a trading program mechanism for the power sector, the degree of flexibility available under this rule is reduced both by the greater stringency of the overall emissions reduction requirements, which leave less room to accommodate emissions from high-emitting units such as uncontrolled coal-fired units, and by the backstop daily emissions rate provisions. However, the EPA maintains that the trading program structure still is significantly more flexible than an array of directly enforceable emissions limits imposed on all EGUs or even on all coal-fired EGUs, and the comments do not show otherwise.

With respect to the comments concerning the timing for application of the backstop daily emissions rate provisions to EGUs without existing SCR controls, in the final rule the provisions will apply to these units starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. As discussed in section VI.B.1.d of this document, the purpose of this change from the proposal is to address concerns expressed by RTOs and other commenters that application of the backstop daily NO_X emissions rate to EGUs without existing SCR controls starting in the 2027 control period would provide insufficient time for planning and investments needed to facilitate the unit retirements they viewed as likely to be a preferred compliance pathway for some owners. The EPA recognizes that retrofitting new emissions controls on aging coal-fired EGUs may be less environmentally efficient than the alternative of retirement and replacement, which could yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have already been considering retirement in 2028 (or earlier) under compliance pathways available under the Clean Water Act effluent guidelines[337] and the coal combustion residuals rule under the

[336] The owner of one of the five plants with common stacks submitted comments stating that no location in the plant's ductwork could meet the criteria for a unit-specific monitoring location. As discussed in section VI.B.10 of this document, EPA staff have reviewed the comment and do not believe the commenter has provided sufficient information to reach such a conclusion.

[337] See 40 CFR 423.11(w).

Resource Conservation and Recovery Act.[338] The year 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.[339] In addition, other regulatory actions at the state or Federal level are being or recently have been proposed. This includes among other things a proposed revision to the PM NAAQS for which transport SIPs would be due later in the 2020s. We understand that EGUs may wish to take the entire regulatory and market landscape into account when deciding whether to invest in SCR or pursue other NO_X reduction strategies. To facilitate a unit-level compliance alternative under this rule that maintains the NO_X reductions corresponding to SCR-level emissions control performance required by the state budgets from 2026 forward and that is potentially superior both economically and environmentally across multiple regulatory programs than installation of new, capital-intensive, post-combustion controls, the EPA is providing the fleet more flexibility in how to achieve those emissions reductions in the years through 2029. Relatedly, the deferral of the application of the backstop emissions rate provisions to uncontrolled units also addresses commenters' concerns that the provisions otherwise would reduce the ability of uncontrolled units to operate as needed to back up intermittent renewable generation (subject of course to the allowance-holding requirements to cover emissions). The deferral addresses this concern directly for the period through 2029, by eliminating application of the backstop provisions to uncontrolled EGUs through this period, and also indirectly after 2029, by ensuring the availability of sufficient time for owners and operators to complete other investments that may be needed to back up renewable generation after that point.

The EPA disagrees with the comments stating that application of the backstop daily emissions rate provisions to uncontrolled units should not be deferred and also disagrees with the comments stating that deferral should be accompanied by increases in the state emissions budgets reflecting higher assumed emissions rates for these units. The responses to these two comments are related. This rule complies with the mandate for the EPA to address good neighbor obligations as expeditiously as practicable and is based on a demonstration that emissions reductions commensurate with the overall emissions control strategy at Step 3 can be achieved beginning in the 2027 ozone season (following a two-year phase in of emissions reductions associated with installation of SCR retrofits). In the *RIA,* we demonstrate that EGUs will have multiple pathways to meeting the state budgets even if they choose not to install the SCR controls—thus no relaxation in the stringency of these budgets has been demonstrated to be warranted based on feasibility, necessity, or impossibility. The EGU economic modeling discussed in the *RIA* illustrates that many sources identified as currently having SCR retrofit potential elect not to install a SCR, and those that do retrofit SCR make no such installation until 2030. Yet, the fleet is able to comply with 2026 state emissions budgets (whose emissions reductions are premised in large part on assumed SCR retrofits) through reduced utilization (many of these units are projected to retire, and thus reduce emissions). While these changes in coal fleet utilization are not required or imposed through the EPA's state emissions budgets, they are projected to be an economic preference for a substantial portion of the unretrofitted fleet owing to future market and policy conditions. If sources do ultimately elect this pathway, then compliance will occur with significantly less demand on SCR retrofit labor and material markets than assumed at Step 3. The daily emissions rates are a backstop to the broader emissions reduction requirements, which we view as an important and necessary component to the elimination of significant contribution. But we also recognize that the objectives to be accomplished by the backstop must be balanced with larger economic and environmental conditions facing EGUs for which a deferral of the backstop rate ultimately is the most reasonable approach given these competing concerns. *See Wisconsin,* 938 F.3d at 320 (''EPA, though, possesses a measure of latitude in defining which upwind contribution 'amounts' count as 'significant[ ]' and thus must be abated.''). As noted in section VI.B.1.d of this document, the EPA finds that as long as state emissions budgets continue to reflect the required degree of emissions reductions at least for an interim period until the backstop rate would apply more uniformly, deferral of the backstop rate requirement for uncontrolled units in recognition of the transition period identified by commenters can be justified on the basis of the greater long-term environmental benefits obtained through greater compliance flexibility.

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, 906–08 (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.[340] Both of the exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped,

[338] See 40 CFR 257.103(b).

[339] See 40 CFR 51.308(f).

[340] Information on the assurance level exceedances in the 2019, 2020, and 2021 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); 87 FR 57695 (September 21, 2022).

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, the 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 the 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 in this rulemaking is revising the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances starting with the 2024 control period. 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 transitioning from the Group 2 trading program to the Group 3 trading program, the EPA is promulgating the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[341]

The two historical 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 instead adding 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 will not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but will trigger the possible application of the CAA's enforcement authorities. The new emissions limitation will be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point is being 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.'')

Because the purpose of the new unit-level secondary emissions limitation is to deter conduct causing exceedances of a state's assurance level, the EPA is conditioning 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 will be carried out according to the existing assurance provision procedures and will 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. To ensure that the secondary emissions limitation is focused on units where the need for improved incentives is greatest, and also to ensure that the limitation will not apply to units used only to meet peak electricity demand, the limitation applies only to units that are equipped with post-combustion controls (*i.e.,* SCR or SNCR) and that operated for at least ten percent of the hours in the control period in question and in at least one previous control period.

For units to which a secondary emissions limitation applies in a given control period based on the conditions just summarized, the limitation is defined by a formula in the regulations. The formula is generally designed to compute the potential amount the unit would have emitted during the control period, given its actual heat input during the control period, if the unit had achieved an average emissions rate equal to the unit's lowest average emissions rate in a previous control period plus a margin of 25 percent. To ensure that the data used to establish the unit's lowest previous average emissions rate are representative and of high quality, only past control periods where the unit participated in a CSAPR trading program for ozone season NO_X and operated in at least ten percent of the hours in the control period are considered. Further, to avoid causing units that achieve emissions rates lower than 0.08 lb/mmBtu from becoming subject to more stringent secondary emissions limitations in subsequent control periods, the secondary emissions limitation formula uses a

[341] 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 doing 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.

floor emissions rate of 0.10 lb/mmBtu (which is 0.08 lb/mmBtu plus the formula's 25 percent margin). In addition to making sure that performance better than 0.08 lb/mmBtu is not disincentivized, the inclusion of the floor emissions rate also ensures that no unit achieving an average emissions rate of 0.10 lb/mmBtu or less in a given control period will exceed a secondary emissions limitation in that control period. Finally, the formula includes a 50-ton threshold, which will avert violations for small performance deviations at large EGUs and also ensure that no unit emitting less than 50 tons in a given control period will exceed a secondary emissions limitation in that control period.

In summary, a secondary emissions limitation is applicable to a unit for a given control period only if the state's assurance level is exceeded, responsibility for the exceedance is apportioned at least in part to the set of units represented by the unit's designated representative, the unit is equipped with post-combustion controls, and the unit operated for at least ten percent of the hours in the control period. Where a secondary emissions limitation applies to a unit for a given control period, the amount of the limitation is computed as the sum of 50 tons plus the product of (1) the unit's heat input for the control period times (2) a NO_X emissions rate of 0.10 lb/mmBtu or, if higher, 125 percent times the lowest seasonal average NO_X emissions rate achieved by the unit in a previous control period when the unit participated in a CSAPR trading program for ozone season NO_X emissions and operated in at least ten percent of the hours in the control period.[342]

Table VI.B.8–1 shows the secondary emissions limitations that the 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 2020 and 2021 when assurance level exceedances occurred in Missouri. Following consideration of comments, the EPA believes that in each case the formula functions in a reasonable manner, and the Missouri 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 VI.B.8–1 does not show any units that would have been identified as subject to secondary emissions limitations in the case of the 2019 and 2020 assurance level exceedances in Mississippi because no units in the state meeting all conditions for applicability—including the requirement to be equipped with post-combustion controls—exceeded their respective limitations.

TABLE VI.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	125% of Lowest previously achieved NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
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 secondary emissions limitation formula to other units in the states 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 VI.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 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 secondary emissions limitation provisions are being finalized as proposed except for the addition of the condition that a unit to which the provisions apply must be equipped with post-combustion controls. The EPA's responses to comments concerning the secondary emissions limitation provisions, including the comments giving rise to the change just mentioned, are in the remainder of this section and section 5 of the *RTC* document.

Comment: Some commenters stated that the secondary emissions limitation is not necessary, or would be a disproportionate remedy, because experience shows that exceedances of the assurance level have been rare, and where exceedances of a state's assurance level have occurred, the 3-for-1 surrender ratio under the existing regulations has applied, providing a sufficient remedy.

Response: The EPA disagrees with these comments. The purpose of the assurance provisions in the CSAPR trading programs is to ensure that the emissions reductions required to address a state's obligations under the Good Neighbor Provision occur ''within the state'' as mandated by the CAA. See *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). Prior to this action, the sole consequence for an exceedance of a state's assurance level

[342] For the actual regulatory language, see 40 CFR 97.1025(c) as added by this rule.

has been a requirement to surrender two additional allowances for each ton of the exceedance. The repeated, large, foreseeable, and easily avoidable exceedances of Missouri's assurance level under the Group 2 trading program in 2020 and 2021 have made clear that a remedy based solely on additional allowance surrenders is insufficient to address this statutory requirement and that a materially stronger deterrent is needed.

Comment: Some commenters stated that the secondary emissions limitation could apply to exceedances caused by factors outside the control of the EGU operator, going beyond the EPA's intent of deterring exceedances that are foreseeable and avoidable. For example, commenters pointed out that some units that typically combust gas may sometimes be ordered to combust oil at times when supplies of gas are constrained and expressed concern that the resulting higher NO_X emissions could cause a unit to exceed its secondary emissions limitation. Another commenter stated that it is not uncommon for units' seasonal average NO_X emissions rate to vary by more than 25 percent across control periods.

Response: The EPA agrees that the secondary emissions limitation is intended to apply to units in a position to avert an exceedance of a state's assurance level. The contention that year-to-year variability of 25 percent in units' seasonal average emissions rates is common is not in itself a persuasive reason to omit the secondary emissions limitation from the final rule, because the mere existence of such variability says nothing about whether the operators of those units could reduce that variability through their operational decisions, and the commenter provided no data regarding the extent to which the historical variability was avoidable. However, the EPA agrees that a secondary emissions limitation should be designed to avoid application to a unit whose increase in emissions rate was caused by mandated combustion of a higher-NO_X fuel than the unit's normal fuel. Moreover, based on the analysis of the secondary emissions limitation formula prepared for the proposal, the EPA has reviewed the applicability of the limitation more generally and has determined that it should apply only to units with post-combustion controls, which are the units with the greatest ability to manage their emissions rates through their operating behavior. This modification will avoid application of a secondary emissions limitation in situations where a unit's increase in seasonal average NO_X emissions rate relative to past control periods is caused by factors in that control period beyond the operator's control, such as being mandated by a regulator to combust a higher proportion of oil or operating for a higher proportion of hours at load levels where the unit has a higher NO_X emissions rate for reasons other than non-operation of emissions controls.

Comment: Some commenters asserted that because it is not known if a state's assurance level has been exceeded until after the end of the control period, EGU operators would be unable to know whether the secondary emissions limitation would apply to them during the control period. Some of these commenters suggested that where a unit has been found to have contributed to an assurance level exceedance, the EPA should apply a secondary emissions limitation to the unit not in that control period but instead in the following control period.

Commenters suggested that uncertainty about whether a unit would be subject to a secondary emissions limitation could have a variety of undesirable consequences. For example, they asserted that some EGUs could become unwilling to operate when needed for reliability because they would be concerned that merely operating more than in previous control periods could cause a unit to exceed its limitation. One commenter asserted that the uncertainty would make it difficult for an owner of multiple EGUs to use allowances allocated to one EGU to meet another EGU's surrender requirements, possibly leading to operating restrictions on multiple EGUs.

Response: The EPA disagrees with these comments. While an operator cannot be certain that the secondary emissions limitation *will* apply to a particular EGU until after the end of a control period, the operator can be certain that the limitation *will not* apply to a particular EGU simply by ensuring that the unit's seasonal average NO_X emissions rate does not exceed the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under a CSAPR trading program (excluding control periods where the unit operated for less than 10 percent of the hours). Because any operator of a unit with post-combustion controls can readily avoid being subject to the limitation, there is no need for application of the limitation to be deferred to the following control period. Deferral of the limitation's application would also have the effect of excusing a unit's first contribution to an assurance level exceedance, which the EPA views as inappropriate when that exceedance could have been avoided.

The asserted possible consequences of uncertainty about whether the limitation would apply rest on mischaracterizations of the provision. The formula for the limitation reflects the unit's actual heat input for the control period, so there is no penalty for increased operation as long as the unit's seasonal NO_X average emissions rate stays below the level just referenced. Finally, nothing about the secondary emissions limitation disincentivizes an EGU fleet owner from transferring allocated allowances among the fleet's EGUs, because apportionment of responsibility for an assurance level exceedance—one of the conditions for application of the secondary emissions limitation—is determined at the level of the group of units represented by a common designated representative (typically the set of all units operated by a particular owner) rather than the individual unit.

Comment: Some commenters stated that the EPA should revise the secondary emissions limitation formula so that where a limitation applies to a unit, the unit's previous NO_X emissions rate used in the formula would not be subject to any floor. These commenters also recommended that if the secondary emissions limitation provisions are not finalized, the EPA instead should raise the allowance surrender ratio applied to exceedances of the assurance level in this final rule.

Response: The EPA disagrees with the suggestion to remove the emissions rate floor from the secondary emissions limitation formula, which would have the effect of making the limitation more stringent for any unit that has achieved a seasonal average NO_X emissions rate lower than 0.08 lb/mmBtu in a past control period. As indicated by their label, the secondary emissions limitation provisions play a secondary role in the Group 3 trading program regulations, specifically to provide the strongest possible deterrent against conduct leading to foreseeable and avoidable exceedances of a state's assurance level. The distinguishing feature of the secondary emissions limitation provisions is therefore the remedy for an exceedance, which is potential application of the CAA's enforcement authorities. The trading program's primary role of achieving required emissions reductions in a more flexible and cost-effective manner than command-and-control regulation is played by the primary emissions limitation provisions, which are structured as allowance surrender requirements. Within this overall trading program structure, the EPA considers it sufficient for the operation of units at emissions rates lower than 0.08 lb/mmBtu to be incentivized through the allowance surrender requirements instead of being mandated through potential application of the CAA's enforcement authorities.

The recommendation to raise the allowance surrender ratio applicable to exceedances of the assurance level if the secondary emissions limitation is not finalized is moot because the secondary emissions limitation is being finalized.

9. Unit-Level Allowance Allocation and Recordation Procedures

In this rule, the EPA is establishing 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. Like the allocation processes established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised allocation process finalized in this rule is designed to provide default allowance allocations to all units that are subject to allowance holding requirements. The EPA's allocations and allocation procedures apply for the 2023 control period [343] and, by default, for subsequent control periods unless and until a state or tribe provides state-determined or tribe-determined allowance allocations under an approved SIP revision or tribal implementation plan.[344]

The default allocation process for the Group 3 trading program as updated in this rule involves three main steps. First, portions of each state emissions budget for each control period are reserved for potential allocation to units that are subject to allowance holding requirements and that might not otherwise receive allowance allocations in the overall allocation process, including both ''existing'' units in any areas of Indian country not subject to a state's CAA implementation planning authority as well as ''new'' units anywhere within a state's borders.[345] Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible existing units, any portion of the state budget reserved for existing units in Indian country not subject to the state's CAA implementation planning authority is allocated among those units, 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 portion of the budget reserved for new units 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.

While the overall three-step allocation process summarized in this section was also followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rule the EPA is making revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the dynamic budget-setting process discussed in section VI.B.4 of this document. The revisions to the three steps are discussed in sections VI.B.9.a, VI.B.9.b, and VI.B.9.c, respectively.

a. Set-Asides of Portions of State Emissions Budgets

The first step of the overall unit-level allocation process for a given control period involves reserving portions of each state's budget for the control period in ''set-asides.'' In this rule, the EPA is making several revisions affecting the establishment of set-asides. The first revision, which is largely unrelated to the other aspects of this rulemaking, will update the regulations for the Group 3 trading program [346] 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.[347] Consistent with this holding, the EPA is revising language in the Group 3 trading program regulations that prior to this rule, for purposes of allocating allowances from a given state's emissions budget, distinguished 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 now 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 more accurately distinguishes 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 revision is that any 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 will 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.[348]

The remaining revisions, which are interrelated, concern the types of set-asides that in the context of this rule will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would

[343] The rule does not include an option for states to replace the EPA's unit-level allocations for the 2023 control period because the Agency believes a process for obtaining appropriately authorized allowance allocations determined by a state or tribe could not be completed in time for those allocations to be recorded before the end of the 2023 control period.

[344] The options for states to submit SIP revisions that would replace the EPA's default allowance allocations are discussed in sections VI.D.1, VI.D.2, and VI.D.3 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 the EPA's default allocations for subsequent control periods.

[345] Under this rule, the unit-level allocations to ''existing'' units are generally computed in the year before the year of each control period, and the determination of whether to treat a particular unit as existing for purposes of that control period's allocations is made as part of the allocation process, generally based on whether the Agency has the data needed to compute an allocation for the unit as an existing unit. A unit that is subject to allowance holding requirements for a given control period and that did not receive an allocation for that control period as an existing unit is generally eligible to receive an allocation from the portion of the budget reserved for ''new'' units. For further discussion of which units are considered eligible for allocations as existing units or new units in particular control periods, see sections VI.B.9.b and VI.B.9.c.

[346] As discussed in section VI.B.13, the EPA is also making this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

[347] 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 III.C.2.

[348] The EPA notes that the units that will be treated for allocation purposes in the same manner as units not in Indian country will 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 III.C.2).

not otherwise receive allowance allocations. One 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 rule will 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. To provide an option for Utah (or a similarly situated state in the future) to replace the Agency'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, which is not subject to the state's jurisdiction or control (or similarly situated units in the future), the EPA is revising 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 set of units within a state's borders eligible to receive allocations as existing units includes one or more units [349] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA will 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 will 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 VI.B.9.b of this document). 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 later in this section), the EPA will 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 will have no substantive effect unless and until the relevant state chooses to replace the 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.[350] The EPA believes the establishment of Indian country existing unit set-asides accomplishes the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while ensuring that the allocations to units in Indian country not covered by such authority remain under Federal authority (unless replaced by a tribal implementation plan).

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 Group 3 trading program regulations as in effect before this rule, allowances for new units have been provided from separate new unit set-asides and Indian country new unit set-asides. Under this rule, the EPA is combining 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 will continue to administer the new unit set-asides in the event a state chooses to replace the 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 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. 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.[351] 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 the EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to maintain Federal implementation authority and ensure that the units in Indian country would receive an appropriate share of any reallocated allowances.[352] The principal difference between the new unit set-asides and the Indian country new unit set-asides under the regulations in effect before this rule was that, if a state chose to replace the EPA's default allocations with state-determined allocations, the state would take over administration of the new unit set-aside, but not any Indian country new unit set-aside.

[349] In coordination with the dynamic budgeting process discussed in section VI.B.4, each unit included in the unit inventory used to determine a state's dynamic emissions budget for a given control period in 2026 or a later year will be considered an ''existing'' unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there will no longer be a single fixed date that divides ''existing'' from ''new'' units.

[350] As noted in section VI.D, 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.

[351] Under the regulations in effect before this final rule, allowances from an Indian country new unit set-aside that are not allocated to qualifying new units in Indian country are first transferred to the state's new unit set-aside, and if the allowances are not allocated to qualifying new units elsewhere within the state's borders, the allowances are then reallocated to the state's existing units.

[352] 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.

Under the revised regulations finalized in this rule, states will not be able to take over administration of the new unit set-asides in this situation. Therefore, there is no longer any reason to establish separate Indian country new unit set-asides in order to preserve Federal (and potentially tribal) authority to implement the rule in areas of Indian country subject to tribal jurisdiction.

With respect to the total amounts of allowances that will be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 through 2025 (but not for subsequent control periods, as discussed later in this section), the EPA is establishing 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 base 2 percent of the state emissions budget to address any unknown new units, with a minimum total amount of 5 percent. For example, if planned units in a state are projected to emit 4 percent of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 6 percent, which is the sum of the 4 percent for planned units plus the base 2 percent for unknown new units. Alternatively, if planned new units are projected to emit only 1 percent of the state's budget, the new unit set-aside would be set at the minimum 5 percent amount. Except for the addition of the 5 percent minimum, which is a change being made in response to comments, the approach to setting the new unit set-aside amounts is generally 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, the EPA is making an exception for New York for the 2023 through 2025 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.

The final regulations issued under this rule specify the new unit set-aside amounts in terms of the percentages of the state emissions budgets. The amounts are shown in Tables VI.B.9.a–1, VI.B.9.a–2, and VI.B.9.a–3 of this document show the tonnage amounts of the new unit set-asides for the control periods in 2023 through 2025 that are computed by multiplying the new unit set-aside percentages by the preset budgets finalized in this rule for those control periods. The amounts of the 2023 new unit set-asides are illustrative because they do not reflect the impact of transitional adjustments included in the rule that that are likely to affect the 2023 budgets as implemented.[353] The amounts of the 2024 and 2025 new unit set-asides are the actual amounts, because the 2024 and 2025 budgets computed in this rule are the budgets that will be implemented, without any need for transitional adjustments.

TABLE VI.B.9.a–1—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,379	5	319
Arkansas	8,927	5	446
Illinois	7,474	5	374
Indiana	12,440	5	622
Kentucky	13,601	5	680
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,727	5	536
Minnesota	5,504	5	275
Mississippi	6,210	5	311
Missouri	12,598	5	630
Nevada	2,368	9	213
New Jersey	773	5	39
New York	3,912	5	196
Ohio	9,110	6	547
Oklahoma	10,271	5	514
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,755	5	788
Virginia	3,143	5	157
West Virginia	13,791	5	690
Wisconsin	6,295	5	315

[353] As discussed in section VI.B.12, the EPA expects that this final rule will become effective after May 1, 2023, causing the emissions budgets for the 2023 control period to be adjusted under the rule's transitional provisions so as to ensure that the new budgets will apply only after the rule's effective date. The actual new unit set-asides for the 2023 control period will be computed using the adjusted budgets, but the 2023 budget amounts shown in Table VI.B.9.a–1 do not reflect these adjustments.

TABLE VI.B.9.a–2—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	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,999	5	650
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,058	5	253
Missouri	11,116	5	556
Nevada	2,589	9	233
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,384	5	469
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	6,295	5	315

TABLE VI.B.9.a–3—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2025 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,472	5	624
Louisiana	9,107	5	455
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,037	5	252
Missouri	11,116	5	556
Nevada	2,545	9	229
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,376	5	469
Pennsylvania	8,138	5	407
Texas	38,542	5	1,927
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	5,988	5	299

For control periods in 2026 and later years, the EPA will allocate a total of 5 percent 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 will 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 is being codified in the Group 3 trading program regulations and will reflect the same percentage of the emissions budget for all states.

The purpose of the change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that may be used to determine budgets beginning with the 2026 control period. As discussed in section VI.B.4 of this document, under the dynamic budget-setting process, each state's budget for each control period will be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the most recent control periods before the budget-setting computations. (For example, 2026 emissions budgets would be based on 2022–2024 state-level heat input data.) Moreover, as discussed in section VI.B.9.b of this document, the set of units eligible to receive allocations as ''existing'' units in a given control period will generally be the set of units that operated in the control period two years earlier (with the exception of any units whose monitor certification deadlines fell after the start of that earlier control period). Consequently, by the 2025 control period, all or almost all units that commenced commercial operation before issuance of this rule will be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of this rule generally will 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 will 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 it is unnecessary to establish set-aside percentages for some states that are permanently larger than 5 percent based solely on the fact that projected emissions from planned new units happen to be a somewhat larger proportion of those states' overall budgets at the time of this rule's issuance.

The changes to the structure and amounts of set-asides in this rule largely follow the proposal. The EPA received few comments on these topics. As noted previously, one commenter expressed the view that if the amounts of the new unit set-asides were based on 2 percent of the respective states' budgets, the set-asides would be too small in certain circumstances, and in response the final rule bases the amounts of the set-asides on a floor percentage of 5 percent instead of 2 percent. The remaining commenters expressed a concern that the final rule's provisions regarding set-asides should ensure that any tribal decisions relating to allowance allocations would not be constrained by state decisions. The EPA had this same concern in mind when designing the rule and believes that the final set-aside structure—encompassing Indian country existing unit set-asides as well as EPA-administered new unit set-asides for sources in all areas within each state's borders—fully addresses the concern, is equitable, and preserves Federal and tribal authority under this rule for areas of Indian country subject to tribal jurisdiction. The comments and the EPA's responses are discussed in greater detail in section 1 of the *RTC* document.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budget-setting methodology for the Group 3 trading program finalized in this rulemaking, the EPA is necessarily establishing a revised procedure for making unit-level allocations of Group 3 allowances to existing units.[354] The procedure that the EPA is employing 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 procedure for determining allocations from each state emissions budget for each control period are described in detail in the Unit-Level Allowance Allocations Final Rule TSD. The steps are summarized in the following paragraphs, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA identifies the list of units eligible to receive allocations for the control period. The unit inventories used to compute unit-level allocations for the control periods in 2023 through 2025 are the same inventories that have been used to determine the preset emissions budget for these control periods. These inventories have been determined in this rulemaking in essentially the same manner as in the Revised CSAPR Update. The procedures for updating the unit inventories for these control periods are discussed in section VI.B.4 of this document, 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 V.B of this document and in the Ozone Transport Policy Analysis Final Rule TSD.

The unit inventories used to compute unit-level allocations for control periods in 2026 and later years will 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 2026 budgets and allocations will reflect reported data up through the 2024 control period). These inventories, which are generally the same as the inventories used to compute dynamic budgets for each control period, include any unit whose monitor certification deadline was no later than the start of the relevant historical control period and that reported emissions data during the relevant historical control period. The EPA notes that basing the list of eligible units on the list of units that reported heat input in the control period two years earlier than the control period for which allocations are being determined represents a revision to the Group 3 trading program regulations as in effect before this rule concerning the treatment of allocations to retired units. Under the prior regulations, units that cease operations for two consecutive control periods would continue to receive allocations as existing units for three additional years (that is, a total of five years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the regulations as revised in this rule, units that cease operation will 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 that anticipated market conditions (in particular, the incentives toward power sector transition to cleaner generating sources), particularly in the later 2020s, 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 will 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 will 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 will also determine the maximum total NO_X emissions value over the 5-year period. For coal-

[354] The revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading program. In this rulemaking, the EPA is not reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

fired units of 100 MW or larger, the EPA will further determine a ''maximum controlled baseline'' NO_X emissions value, computed as the unit's maximum heat input over the 5-year period times a NO_X emissions rate of 0.08 lb/mmBtu. The maximum controlled baseline will serve as an additional cap on unit-level allocations for all such coal-fired units starting with the control periods in which the assumed use of SCR controls at the units is reflected in the state emissions budgets. Thus, the maximum controlled baseline will apply for purposes of allocations to units with existing SCR controls for all control periods starting with the 2024 control period and for all other coal-fired units of 100 MW or more (except circulating fluidized bed units) starting with the 2027 control period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with three exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA will use data from the most recent five control periods for which data had been reported. (For example, for the 2026 control period, the EPA will use data for the 2020–2024 control periods.) Second, to simplify the data compilation process, the EPA will 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. Third, the use of the maximum controlled baseline as an additional cap on emissions is a change adopted in this rule in response to comments received on the proposal. Specifically, commenters observed that if a state's emissions budget is decreased to reflect an assumption that a particular unit in the state is capable of reducing its emissions through the installation of new SCR controls, but the historical emissions cap applied to that unit in the unit-level allocation methodology does not reflect use of the new controls, then the allocation methodology could have the effect of reducing unit-level allocations to the other units in the state whose historical emissions already reflect use of existing controls rather than the unit assumed to install new controls. The EPA agrees with the comment and in this rule has added the maximum controlled baseline provision to the allocation methodology to mitigate the potential effect identified by the commenters.

In the third step of the procedure for determining allocations to existing units in each state, the EPA will 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 or, if applicable, the unit's maximum controlled baseline. If the allocations to one or more units are curtailed because of the units' applicable caps, the EPA will iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their caps. (If all units in a state reach their caps, any remaining allowances are allocated in proportion to the units' average heat input values, notwithstanding the caps.) This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR), but using caps that reflect both the units' maximum historical NO_X values and also, where applicable, the maximum controlled baseline values.

Illustrative unit-level allocations for the 2023 control period and final unit-level allocations for the 2024 and 2025 control periods are being determined in this rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and are included in the docket. The 2023 allocations are only illustrative because, as discussed in section VI.B.12.a, the EPA expects the effective date of the rule to occur after the start of the 2023 control period and consequently expects the 2023 control period to be a transitional period in which the emissions budgets determined in this rulemaking apply only for the portion of the control period occurring on and after the rule's effective date, while any previously determined emissions budgets apply for the portion of the control period before the rule's effective date. The rule's effective date will become known when the rule is published in the **Federal Register**. As soon as practicable thereafter, the EPA will calculate the final prorated or blended 2023 state emissions budgets and 2023 unit-level allocations based on the transitional formulas finalized in this action (see section VI.B.12.a of this document) and will communicate the information to the public through a notice of data availability. The 2023 and 2024 allocations will then be recorded 30 days after the effective date of the final rule (to provide an interval in which to execute the recall of 2023 and 2024 Group 2 allowances, as discussed in section VI.B.12.c of this document), while the 2025 allocations will be recorded by July 1, 2024.[355]

The default unit-level allocations for each control period in 2026 or a later year will be computed immediately following the determination of the state emissions budgets for the control period. The EPA will perform the 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. There will be a 30-day period in which objections to the data and preliminary computations may be submitted, and the EPA will then make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA will then record the allocations by July 1 of the year before the control period.[356]

All covered states also have options to establish state-determined allowance allocations for control periods in 2024 and later years. As discussed in section VI.D.1 of this rule, a state choosing to establish state-determined allocations for the 2024 control period would need to submit a letter of intent to the EPA by August 4, 2023, and would need to submit the SIP revision with the allocations by September 1, 2023. The EPA would defer recordation of the 2024 allocations for the state's sources until March 1, 2024, to provide time for this process to be completed. As discussed in sections VI.D.2 and VI.D.3 of this rule, a state choosing to establish state-determined allocations for control periods in 2025 and later years would need to submit a SIP revision by December 1 of the year two years before the first year for which state-determined allocations are being established—*e.g.,* by December 1, 2023, for allocations for the 2025 control period—and would need to submit the allocations for each control period by June 1 of the year before the control period—*e.g.,* by June 1, 2024, for allocations for the 2025

[355] The recordation schedule for the 2023 and 2024 allocations represents an expected acceleration of the recordation schedule in effect immediately before this final rule, which called for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded by September 1, 2023. *See* Deadlines for Submission and Recordation of Allowance Allocations Under the Cross-State Air Pollution Rule (CSAPR) Trading Programs and the Texas SO_2 Trading Program (the ''Recordation Rule''), 87 FR 52473 (August 26, 2022).

[356] The current recordation schedule, which provides for almost all allowance allocations to existing units for a given control period under all the CSAPR trading programs to be recorded by July 1 of the year before the year of that control period, was adopted in the Recordation Rule.

control period.[357] The EPA would record any state-determined allocations for control periods in 2025 and later years 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 unit-level allocations.

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—the EPA will follow the states' methodologies to the extent possible in developing the EPA's allocations of Group 3 allowances to the units in those states for the control periods in 2023 through 2025.[358] The EPA will not follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2026 or later years. However, like other states, these three states have options to replace the EPA's default allocations with state-determined allocations through SIP revisions starting with the 2024 control period.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA will 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 provisions governing allocations to existing units are being finalized substantially as proposed, except for the addition of an additional cap on unit-level allocations in response to comments. The EPA's responses to comments on the unit-level allocation provisions for existing units are in section 5 of the *RTC* document.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

The Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside after the end of the control period at issue. 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. Thus, in addition to units that have not yet completed two full control periods of operation since their monitor certification deadlines, units eligible for allocations from the new unit set-asides may also include existing coal-fired units that first lose their eligibility for allocations from the unreserved portion of the applicable state budget by ceasing operation, and then resume operation in a later control period. The regulations call for the EPA to allocate allowances to any eligible ''new'' units in the state generally 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. However, in the case of a unit whose allocation for the control period would have been subject to a maximum controlled baseline if the unit was eligible to receive allocations as an existing unit, the unit's allocation from the new unit set-aside will not exceed a cap equal to the unit's reported heat input for the control period times an emissions rate of 0.08 lb/mmBtu.

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.

This EPA notes that the 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 5 percent of the respective state emissions budgets for the respective control periods. This limit on growth of the 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 full control periods (and possibly a partial control period before those two control periods) before the unit becomes eligible to receive allocations as an ''existing'' unit 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 VI.D.2 and VI.D.3 of this document, 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 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.

The final rule's provisions concerning unit-level allocations from the new unit set-asides are unchanged from the proposal except for the addition of the allocation cap in a given control period for any unit that would have been subject to a maximum controlled baseline if the unit was eligible to receive an allocation as an existing unit

[357] The current deadlines for states to submit state-determined allowance allocations to the EPA were adopted in the Recordation Rule and are coordinated with the schedule for computation of state emissions budgets for control periods in 2026 and later years. For example, for the 2026 control period, by May 1, 2025, the EPA will publish the final state emissions budgets and the EPA's default unit-level allocations; by June 1, 2025, states will submit any state-determined unit-level allocations that would replace the default allocations; and by July 1, 2025, the EPA will record the default unit-level allocations or the state-determined unit-level allocations, as applicable, in sources' compliance accounts.

[358] For discussion of how the EPA is using the previously approved allocation methodologies for Alabama, Indiana, and New York to determine allocations to units in these states for the 2023–2025 control periods, see the Allowance Allocation Final Rule TSD.

for that control period.[359] This change was made to address the same comments discussed in section VI.B.9.b of this document that caused the Agency to add the maximum controlled baseline provision to the procedure for allocating allowances to existing units. The Agency did not receive any other comments on the proposed provisions concerning unit-level allocations of allowances from the new unit set-asides.

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 provisions as in effect prior to this rule have generally called 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 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 is therefore finalizing revisions to provide 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) will be transferred to a surrender account instead of being reallocated to other units in the state. The EPA received no comments on this proposed revision, which is being finalized as proposed.

10. 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. Under 40 CFR part 75, a given unit may have several options for monitoring and reporting. Any unit can use CEMS. Qualifying gas- or oil-fired units can use certain excepted monitoring methodologies that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data. Certain non-coal-fired, low-emitting units can use a low mass emissions (LME) methodology, and sources can seek approval of alternative monitoring systems approved by the Administrator through a petition process. 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 quarterly reports will contain all the data required concerning ozone season NO_X emissions under the Group 3 trading program.

In this rulemaking, as proposed, the EPA is making two changes to the Group 3 trading program's previous requirements related to monitoring, recordkeeping, and reporting. First, the EPA is revising the monitor certification deadline in the Group 3 trading program regulations applicable to certain units that have not already certified monitoring systems for use under 40 CFR part 75. This revision is expected to provide approximately 15 EGUs in Nevada and Utah with 180 days following the rule's effective date to certify monitoring systems, with the consequence that the units are expected to become subject to allowance holding requirements under the Group 3 trading program starting with the 2024 control period. Second, to implement the trading program enhancements, the EPA is adding certain new recordkeeping and reporting requirements, which will be implemented through amendments to the regulations in 40 CFR part 75 and will apply starting January 1, 2024. Sources generally will be able to meet the additional recordkeeping and reporting requirements using the data that are already collected by their current monitoring systems, and the EPA is not requiring the installation of additional monitoring systems at any source. However, a small number of sources with common stacks could find it advantageous to upgrade their monitoring systems so as to monitor at the individual units instead of monitoring at the common stack. The Group 3 trading program monitor certification deadline revisions and the additional recordkeeping and reporting requirements are discussed in sections VI.B.10.a and VI.B.10.b, respectively.[360]

a. Monitor Certification Deadlines

In general, a unit subject to the Group 3 trading program must monitor and report emissions data using certified monitoring systems starting as of the date the unit enters the trading program or, if later, 180 days after the unit commences commercial operation. Where an EGU has already certified and maintained monitoring systems in accordance with 40 CFR part 75 for purposes of another trading program, no recertification solely for purposes of entering the Group 3 trading program is required. Under these pre-existing provisions of the Group 3 trading program regulations, nearly all currently operating EGUs transitioning to the trading program under this rule are positioned to begin monitoring and reporting under the trading program as of their dates of entry (or if later, 180 days after they commence commercial operation) because of the units' previous requirements to monitor and report emissions under other programs including the CSAPR NO_X Ozone Season Group 2 Trading Program (for

[359] As discussed in section IX.B of this rule, the EPA is relocating some of the regulatory provisions relating to administration of the new unit set-asides and is also removing certain provisions that are made obsolete by revisions to other provisions of the Group 3 trading program regulations.

[360] The EPA is not amending 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 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 additional recordkeeping and reporting requirements will also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the additional requirements will also apply for the ozone season only.

units in Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), the CSAPR NO_X Annual Trading Program (for units in Minnesota), and the Acid Rain Program (for most units in Nevada and Utah).

As discussed in section VI.B.3 of this document, the EPA has identified 15 potentially affected units in Nevada and Utah that commenced commercial operation more than 180 days before the effective date of this rule and that do not currently report emissions data to the Agency under 40 CFR part 75.[361] To ensure that units in this situation have sufficient time to certify monitoring systems as required under this rule, the final rule establishes a monitoring certification deadline of 180 days after the effective date of the rule for affected units that are not already required to report emissions under 40 CFR part 75 under another program, equivalent 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 will likely fall after the end of the 2023 ozone season, with the result that the certification deadline will be extended until May 1, 2024, the first day of the 2024 ozone season. Because the Group 3 trading program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently will become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.

The EPA received no comments on the provisions establishing a monitor certification deadline 180 days after the effective date of this rule for affected units that are not already required to report emissions under 40 CFR part 75, and the provisions are being finalized as proposed.

b. Additional Recordkeeping and Reporting Requirements

To facilitate implementation of the backstop daily NO_X emissions rates for certain coal-fired units, the secondary emissions limitations for units contributing to assurance level exceedances, and the revised default unit-level allowance allocation procedures, the final rule amends 40 CFR part 75 to establish two sets of additional recordkeeping and reporting requirements. The first set of additional recordkeeping and reporting requirements is specific to the backstop daily emissions rate provisions. Starting January 1, 2024, units listing coal as a fuel in their monitoring plans, serving generators of 100 MW or larger, and equipped with SCR controls on or before the end of the previous control period (except circulating fluidized bed units) will 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 backstop daily NO_X emissions rate. The units will also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rate for the ozone season and any portion of such cumulative NO_X emissions exceeding 50 tons. Starting January 1, 2030, the same recordkeeping and reporting requirements will apply to all units listing coal as a fuel in their monitoring plans and serving generators of 100 MW or larger (except circulating fluidized bed units), including units not equipped with SCR controls. These data will be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. Implementation of these 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.

The second type of additional recordkeeping and reporting requirements applies to units exhausting to common stacks. For these units, 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 have also been required historically to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically have computed 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 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 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 provisions, the final rule requires 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 January 1, 2024. To obtain the necessary unit-level hourly mass emissions values, the revised regulations rule 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 apportionment procedure is very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Where sources choose to obtain the additional required data values through apportionment, implementation of the additional recordkeeping and reporting requirements will necessitate a one-time update to the units' data acquisition and handling systems but will not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

For most units sharing common stacks, the EPA expects that the reported unit-specific hourly NO_X emissions values computed through the apportionment procedures will 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, particularly those where SCR-equipped and non-SCR-equipped coal-fired units share a common stack, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for the SCR-equipped units and correspondingly understate the reported NO_X mass emissions for the non-SCR-equipped units.[362] As proposed, the

[361] The units are listed in Table VI.B.3–1.

[362] The EPA is aware of five plants in the states covered by this rule where SCR-equipped and non-SCR-equipped coal-fired units exhaust to a common stack: Clifty Creek in Indiana; Cooper, Ghent, and Shawnee in Kentucky; and Sammis in Ohio. The owners of the Sammis plant have announced plans to retire the plant in 2023.

final rule leaves in place the existing options under 40 CFR part 75 for plants to upgrade their monitoring equipment to monitor on a unit-specific basis instead of at the common stack. Plant owners may find this option attractive if they believe it would reduce the quantities of reported emissions exceeding the backstop daily emissions rate.

The EPA is finalizing the additional recordkeeping and reporting requirements generally as proposed, with modifications as needed to accommodate the changes in the backstop daily emissions rate provisions from proposal discussed in sections VI.B.1.c.i and VI.B.1.7. No comments were received on the recordkeeping and reporting requirements added to facilitate implementation of the backstop daily emissions rate. Comments on the requirement to report unit-specific NO_X emissions data for units sharing common stacks are addressed in the following paragraphs.

Comment: Some commenters claimed that for plants where SCR-equipped and non-SCR-equipped coal-fired units share common stacks, the rule as proposed would have effectively mandated installation of unit-specific monitoring systems in order to comply with the backstop daily emissions rate provisions. The commenters generally requested that application of the backstop daily rate provisions be delayed for plants with common stacks until all units sharing the stacks were subject to the provisions. Alternatively, they claimed that the EPA should consider the cost of the additional unit-specific monitoring system to be a cost of the rule.

One commenter claimed that the option to install unit-specific monitoring systems for the units sharing a common stack at its plant was not feasible because of a lack of locations in the units' ductwork suitable for installation of the monitoring equipment. Specifically, the commenter claimed that EPA Method 1 requires monitoring equipment to be located at least eight duct diameters downstream and two duct diameters upstream of any flow disturbance and stated that the units had no straight runs of ductwork sufficiently long to meet these criteria.

Response: The EPA's response to comments about the application of backstop rate requirements to units sharing common stacks is in section VI.B.7 of this document. With respect to assertions that the rule effectively mandates installation of unit-specific monitoring systems, the EPA disagrees. Although the EPA pointed out the option in the proposal, anticipating that owners of some units sharing common stacks might find it advantageous to upgrade their monitoring systems, the final rule does not mandate such upgrades and explicitly provides a reporting option that can be used if a plant owner continues to monitor only at the common stack. For example, a plant owner might choose not to upgrade monitoring systems if the owner does not plan to operate the non-SCR-equipped units sharing the stack frequently. Regarding the contention that the cost of additional monitoring systems should be considered a cost of the rule, the EPA notes that the monitoring cost estimates that the Agency regularly develops for 40 CFR part 75 already reflect the conservative assumption that all affected units perform monitoring on a unit-specific basis.

With respect to the comment asserting an inability to install unit-specific monitoring equipment because of a lack of suitable locations, the EPA does not believe the commenter has provided sufficient information to support the assertion. Although the commenter cites the EPA Method 1 location criteria, the CEMS location provisions in 40 CFR part 75 do not reference those location criteria but instead reference the EPA Performance Specification 2 location criteria, which recommend that a CEMS be located at least two duct diameters downstream and a half duct diameter upstream from a point at which a change in pollutant concentration may occur.[363] Thus, while the commenter states that its units do not have straight runs of ductwork ten duct diameters long, the relevant siting criteria actually call for straight runs of ductwork only 2.5 duct diameters long, and the commenter has not provided information indicating that these criteria could not be met. Moreover, even EPA Method 1 does not require monitoring equipment to be located eight duct diameters upstream and two duct diameters downstream of any flow disturbance. While the method recommends those distances as the first option, the method also allows for locations two duct diameters upstream and a half duct diameter upstream from any flow disturbance, as well as other locations if certain performance criteria can be met.[364]

[363] Appendix B to 40 CFR part 60, Performance Specification 2, sec. 8.1.2; *see also* appendix A to 40 CFR part 75, section 1.1.

[364] Appendix A–1 to 40 CFR part 60, Method 1, sec. 11.1.

11. Designated Representative Requirements

As noted in section VI.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 existing designated representative provisions in the Group 3 trading program regulations already provide that the 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 have participated in the Group 2 trading program and that are transitioning to the Group 3 trading program under this rule 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.

For a source that is newly affected under the Group 3 trading program and that is not currently affected under the Group 2 trading program, a designated representative who has been duly authorized by the source's owners and operators must submit a new or updated certificate of representation to the EPA. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until a certificate of representation has been submitted for the source. If a source is also affected under other CSAPR trading programs or the Acid Rain Program, the same individual must be the source's designated representative for purposes of all the programs.

The EPA did not propose and is not finalizing any changes to the designated representative requirements. The EPA received no comments on the provisions of the proposal relating to these requirements.

12. Transitional Provisions

This section discusses several provisions that the EPA will implement to address the transition of sources into the Group 3 trading program as revised. The purposes of the transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: first, addressing the likelihood that the effective date of this rule 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.[365] However, the sources that will be participants in the revised Group 3 trading program under this rule are transitioning from several different starting points—with some sources already in the existing Group 3 trading program, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. The EPA is therefore finalizing 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

The EPA expects that the effective date of this rule will fall after the start of the Group 3 trading program's 2023 control period on May 1, 2023, because the effective date of the rule will be 60 days after the date of the final rule's publication in the **Federal Register**. The EPA is addressing this circumstance 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.[366] Variability limits, assurance levels, and unit-level allocations for 2023 will all be computed using the appropriately prorated emissions budgets amounts.[367]

As discussed in section VI.B.2 of this document, in the case of the three 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—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the later of May 1, 2023, or the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, and were therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. Assuming that the final rule becomes effective after May 1, 2023, as expected, the EPA will determine prorated emissions budgets for the 2023 control period 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 for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season (*i.e.,* May 1, 2023 through September 30, 2023) exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance, yielding prorated assurance levels that equal a minimum of 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA will apply the unit-level allocation procedure described in section VI.B.9 to the prorated budgets. All calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the rule's effective date. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the 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 will 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 will not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, but the EPA has also retained in the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. The EPA has added a provision to the regulations indicating that the emissions budgets promulgated in the Revised CSAPR Update will 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 will 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 will 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 previous and revised emissions budgets. (For example, if the final rule becomes effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget will equal the sum of 10/153 times the previous emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance,

[365] As discussed in section VI.B.1.d, the EPA is not creating a "safety valve" mechanism in this rule analogous to the voluntary supplemental allowance conversion mechanism established under the Revised CSAPR Update, but intends in the near future to propose and take comment on potential amendments to the Group 3 trading program that would add an auction mechanism to the regulations for the purpose of further increasing allowance market liquidity in conjunction with other appropriate changes to ensure program stringency is maintained. While these changes may provide an additional measure of assurance to the market that allowances will be available for compliance to a degree consistent with the Step 3 emissions control stringency, the EPA does not anticipate that market liquidity concerns pose a challenge to the feasibility of sources to comply with the Group 3 trading program as finalized in this action.

[366] As discussed in sections VI.B.7 and VI.B.8, the revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, will not take effect until the 2024 control period or later.

[367] The EPA notes that transitional provisions similar to the prorating provisions being finalized in this rule were finalized and implemented without issue under the Revised CSAPR Update.

yielding blended assurance levels that equal a minimum of 121 percent of the blended emissions budgets. Unit-level allocations will be determined by applying the allocation procedure described in section VI.B.9 to the blended budgets. Again, all calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the effective date of this rule. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the rule's effective date, as discussed in section VI.B.2 of this document, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program will not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states 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 has added 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 program regulations, which are being 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 rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which are being 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 rule's effective date. The procedures and timing for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, as well as the timing for the recordation of unit-level allocations, are the same as for the states currently in the Group 3 trading program.

Beginning administrative implementation of the Group 3 trading program starting on May 1, 2023, for sources currently in the Group 2 trading program imposes no new or different requirements on these sources. 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 is how the EPA handled the earlier transition of twelve states from the Group 2 to the Group 3 trading program in the Revised CSAPR Update, which was accomplished successfully and without incident. *See* 86 FR 23133–34. This approach 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 the 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 the 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 will implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions will 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 will 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 will 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 in the three states that do not currently participate in the Group 2 trading program or the Group 3 trading program, the 2023 control period will begin on the effective date of the rule, and because the effective date of the rule is expected to fall after May 1, 2023, the 2023 control period for the sources in these states will be shorter than the 153-day length of the 2023 control period for the sources in the remaining states. However, the EPA similarly will implement the revised Group 3 trading program for the sources in these states in a uniform manner for the entire shorter control period.

The prorating provisions are being finalized as proposed. The EPA received no comments on the portion of the proposal discussing these provisions.

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 percent 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 the EPA established the Group 3 trading program and transitioned approximately 55 percent 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 provide for 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 percent 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. The 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,* 938 F.3d at 321.

Under this final rule, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA will 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 transitioning over 80 percent 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 rule the EPA is applying a conversion procedure similar to the procedure followed in the CSAPR Update. Under the conversion procedure in this rule, the EPA has not set a predetermined conversion ratio in the regulations (as was done in the Revised CSAPR Update) but instead has established provisions identifying the target amount of new Group 3 allowances that will be created and defining the types of accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances (as was done in the CSAPR Update). The conversion date will be carried out by September 18, 2023, which is expected to be approximately 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and approximately ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio will be determined as of the conversion date and will 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.

With respect to the numerator of the conversion ratio—that is, the total amount of Group 2 allowances being converted—the EPA has defined the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that will remain in the Group 2 trading program, consistent with the approach taken in the CSAPR Update.[368] Thus, the accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances will 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 will 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 the denominator of the conversion ratio—that is, the target amount of Group 3 allowances that will be created in the conversion process—the EPA has followed the same approach for setting the target amount 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 in this rule will be computed as the sum of the minimum 21 percent variability limits for the 2024 control period[369] established for the ten states being added to the Group 3 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 state emissions budgets and variability limits, the full-season target amount for the conversion would be 23,094 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa, Kansas, and Tennessee exceeding the quantity of allowances likely to be needed for 2022 compliance is approximately 149,386 allowances. Thus, if the quantities of banked Group 2 allowances held in the accounts being included in the conversion do not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 6.5-to-1, meaning that one Group 3 allowance would be created for every 6.5 Group 2 allowances deducted in the conversion process.[370]

As noted in section VI.B.12.a of this document, the EPA expects that the effective date of this rule will occur after

[368] The states whose sources will continue to participate in the Group 2 trading program for the 2023 control period will be Iowa, Kansas, and Tennessee.

[369] 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 basing the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[370] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

the start of the 2023 ozone season, and prorating provisions are being promulgated in this rule 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) will take effect only after the rule's effective date. Consistent with these other procedures, the EPA will 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 23,094 allowances would be prorated to an initial bank target amount of 21,585 allowances.[371] The EPA notes that prorating the bank amount in this manner will not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources will receive for the portion of the 2023 ozone season before the rule's effective date will be based on the trading program budgets for the 2023 control period that were in effect before this rulemaking. These trading program budgets exceed the sources' collective 2022 emissions by approximately 29,789 tons, indicating potentially surplus allowances roughly 1.3 times the full-season bank conversion target amount of 23,094 allowances. Thus, although the prorating procedure will 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 will be more than offset by the quantities of Group 3 allowances that will 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, the EPA's overall objective in establishing the target amount for the allowance conversion is to achieve a total target amount for the bank at a level high enough to accommodate year-to-year 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. The EPA believes that a well-established trading program should be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VI.B.6 of this document with respect to the bank recalibration process that will begin with the 2024 control period. However, the 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 will 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 established 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 will 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, the 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 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 will be removed from the program in the bank recalibration process that will be implemented starting with the 2024 control period and therefore will not weaken sources' incentives to control emissions on a permanent basis.

The rule's provisions relating to the creation of an incremental Group 3 allowance bank are being finalized as proposed. Comments on the creation of the incremental allowance bank are discussed in section 5 of the *RTC.*

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, the EPA is recalling 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 states and areas of Indian country transitioning to the Group 3 trading program and recorded in the sources' compliance accounts. The recall provisions 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 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 allow Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the 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

[371] $23{,}094 \times (153 - 10) \div 153 = 21{,}585$.

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 is determining that, 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 doing through the recall provisions.

In this rule, the EPA is implementing 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 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 are 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 later in this section. However, an exception is 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 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 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.[372]

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 will 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.[373] 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 can choose from two possible deadlines for meeting the requirements. The optional first deadline will be 15 days after the effective date of this rule.[374] As soon as practicable or after this date, the EPA will 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 will 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 will first deduct allowances allocated for that control period and then will 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 will be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions will 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 will first deduct allowances that were initially recorded in that account, in the order of recordation, and will 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

[372] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the rule to address the theoretical possibility of such a situation.

[373] The first control period for the Group 2 trading program was in 2017.

[374] As discussed later in this section and in section VI.B.9.b, the EPA has conditioned recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the recall requirements for Group 2 allowances. The purpose of providing an optional first deadline for the recall provisions 15 days after a final rule's effective is to ensure that sources have an early opportunity to comply with the recall provisions to be eligible to have allocations of Group 3 allowances recorded in their accounts 30 days after the final rule's effective date. Because the vast majority of sources subject to the recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources will easily be able to comply with the optional first recall deadline.

EPA will 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 will be sent to the email addresses most recently provided to the EPA for the recipients and will include information on how to contact the EPA with any questions. The EPA has provided that no allocations of Group 3 allowances will 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 this rule will 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 will 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 will 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 previously) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted will be the same as described previously 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 from a specified general account) is unsuccessful for a given source, 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 will 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 30, 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.[375] Before making any deduction under this provision, the EPA will send a notification to the authorized account representative for the account in which the allowance is held and will provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision does not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision will 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 30, 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 30, 2022, all market participants 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.[376]

The final revised regulations provide that failure of a source's owners and operators to comply with the surrender requirements will 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 are required to surrender under the recall provisions, the EPA has prepared a list of the sources in the 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 April 30, 2022, 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 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 will 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 recall provisions have been finalized without change from the proposal. The EPA received no comments on the proposed provisions.

13. Conforming Revisions to Regulations for Other CSAPR Trading Programs

As noted in section VI.B.1.a of this document, 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.[377] In this rulemaking, in addition to the revisions to the Group 3 trading program, the EPA is finalizing a set of conforming revisions that concern how various areas of Indian country are

[375] The provision under which the EPA will not deduct Group 2 allowances transferred to unrelated parties before April 30, 2022 from the transferees' accounts does 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.

[376] 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.

[377] The regulations for the Group 3 Trading Program are at 40 CFR part 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.

treated for purposes of the allowance allocation provisions of the regulations for all the CSAPR trading programs.[378]

As discussed in section VI.B.9.a of this document, 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 revising 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 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 VI.B.9.a of this document for the Group 3 trading program, the EPA is revising 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 are affected are identified in section IX.D of this document. The EPA is unaware of any currently operating units that would be affected by this revision to the regulations for the other CSAPR trading programs.

The conforming revisions to the regulations for the other CSAPR trading programs concerning Indian country are being finalized as proposed with no changes. The EPA received no comments on this portion of the proposal.

C. Regulatory Requirements for Stationary Industrial Sources

The EPA is finalizing FIPs with requirements for certain non-EGU industry sources for 20 of the states covered in this final rule. See section II.B of this document for the list of states. The FIPs include new emissions limitations for units in nine non-EGU industries that the EPA finds (as discussed in sections IV and V of this final rule) are significantly contributing to nonattainment or interfering with maintenance in other states. The emissions control requirements of these FIPs for non-EGU sources apply only during the ozone season (May through September) each year, beginning in 2026.

To achieve the necessary non-EGU emissions reductions for these 20 states, the EPA is finalizing the proposed emissions limitations with some adjustments as a result of information received during the public comment period. The final emissions limits apply to the most impactful types of units in the relevant industries and are achievable with the control technologies identified in this preamble and further discussed in the Final Non-EGU Sectors TSD. The non-EGU regulatory requirements unique to each industry that EPA is finalizing after considering public comments are discussed in sections VI.C.1 through VI.C.6 of this document.

These final FIP requirements apply to both new and existing emissions units. The non-EGU emissions limits and compliance requirements will apply in all 20 states (and, as discussed in section III.C.2 of this document, 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 is consistent with the approach that the EPA proposed, and the EPA did not receive any comments specifically objecting to our proposal to regulate new units. This approach will ensure that all new sources constructed in any of the 20 states will be subject to the same good neighbor requirements that apply to existing units under this final rule. This will also avoid creating incentives to move production from an existing non-EGU source to a new non-EGU source of the same type but lacking the relevant emissions control requirements either within a linked state or in another linked state.

Comment: The EPA received several comments regarding the proposed approach of establishing unit-specific emissions limitations for non-EGUs instead of an emissions trading program. Some commenters suggested that a trading program for non-EGUs could provide for operational flexibility and that EPA should allow sources to work with regulatory authorities to develop a trading program. Other commenters generally supported EPA's proposed approach and the decision to not include non-EGUs in an emissions trading program, because the EPA would not need to require sources to unnecessarily install CEMS. Commenters from several states and industry groups generally supported other monitoring options over CEMS, such as parametric monitoring, performance testing, and predictive emissions monitoring systems (PEMS). Additional commenters voiced concern with the expense and burden of continuous parametric monitoring and semi-annual performance tests. Specifically, commenters explained that semi-annual testing should not be required when the emissions limits only apply during the ozone season. Commenters also noted that many non-EGU boilers have recently been relieved from meeting the CEMS requirements under the 1998 NO_X SIP Call and that implementing CEMS on many of the non-EGU sources would be difficult and unnecessary.

Response: The EPA is finalizing a unit-specific approach with rate-based emissions limitations 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. In response to public comments, the EPA has adjusted these requirements as necessary to ensure that the emissions control requirements are achievable while ensuring that the FIPs achieve the necessary emissions reductions from the covered units to eliminate significant contribution to nonattainment and interference with maintenance as discussed in section V of this document. The EPA has concluded that a unit-specific approach is more appropriate for non-EGUs at this time than implementing a trading program and requiring all units to implement rigorous part 75 monitoring and reporting requirements. As explained in the proposal, to be considered for a trading program, non-EGU sources would have to comply with requirements for monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all previous 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. Consistent and accurate measurement of emissions is necessary to ensure that 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

[378] Additional conforming revisions concerning the schedules for the EPA to record allowance allocations in source's compliance accounts and for states to submit state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

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. Many industry and state commenters provided information confirming that many non-EGU units subject to this rulemaking do not currently utilize CEMS and specifically requested that EPA avoid requiring CEMS for all non-EGU industries. The EPA generally agrees that CEMS is not necessary for all non-EGU industries under the approach of this final rule and is finalizing other continuous monitoring, recordkeeping, and reporting requirements, as appropriate, that are specific to each non-EGU industry. The EPA has determined that establishing unit-specific emissions limitations for non-EGUs is a preferable approach in part because it avoids the rigorous monitoring requirements that would be applied to non-EGUs for the first time under a trading program.

Furthermore, to address commenters' concerns regarding non-EGU requirements for performance testing on a semi-annual basis, the EPA has also reduced the frequency of all required performance testing for non-EGU sources to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to demonstrate continuous compliance during the ozone season. The EPA also agrees with commenters that the annual testing requirements need not occur during the ozone season.

In addition, the EPA is modifying the applicability criteria and other regulatory requirements in response to public comments to provide certain compliance flexibilities for non-EGU industries where appropriate. As discussed further in section V.C.1 of this document, the EPA is modifying the requirements for Pipeline Transportation of Natural Gas by finalizing an exemption for emergency engines and allowing any owner or operator of an affected unit to propose a ''Facility-Wide Averaging Plan'' that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. Further, as discussed in section VI.C.5 of this document, the EPA is finalizing a low-use exemption for non-EGU boilers that operates less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. These final rule provisions require controls on the most impactful non-EGU industrial sources while providing the flexibility needed to accommodate unique circumstances on a case-by-case basis.

Comment: Commenters from several non-EGU industries and states raised general concerns regarding the ability for all sources to comply with the proposed emissions limits. Some commenters suggested that the EPA allow for case-by-case limits where necessary, similar to case-by-case RACT determinations. Specifically, commenters operating boilers, furnaces, and MWCs provided general explanations of how some units might not be able to meet the proposed emissions limits and requested that EPA provide for compliance flexibility where a source can demonstrate technical and economical infeasibility.

Response: As explained more in sections VI.C.1 through VI.C.6, the EPA has made several adjustments to the proposed applicability criteria, emissions limits, and compliance requirements in response to public comments and to reduce the costs of compliance with the final rule. For Pipeline Transportation and Natural Gas, the EPA is finalizing emissions averaging provisions and exemptions for emergency engines to allow facilities to avoid installing controls on units with lower actual emissions where the installation of controls would be less cost effective compared to higher-emitting units. For Cement and Concrete Product Manufacturing, the EPA has removed the daily source cap that would have resulted in an artificially restrictive NO_X emissions limit for affected cement kilns that have operated at lower levels due to the COVID–19 pandemic. For Iron and Steel and Ferroalloy Manufacturing, the EPA is finalizing a ''test-and-set'' requirement for reheat furnaces that will require the installation of low-NO_X burners or equivalent technology. The EPA has addressed the economic concerns raised by commenters regarding installation of controls at Iron and Steel facilities by not finalizing the other ten proposed emissions limits that were intended to require the installation of SCR at these facilities. For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions. For boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel Industry, the EPA is finalizing a low-use exemption to eliminate the need to install controls on boilers that would have resulted in relatively small reductions in emissions. Finally, the EPA has modified the monitoring and recordkeeping requirements for all non-EGU industries where possible to reduce the testing frequency to once a year and to provide for alternative monitoring protocols where appropriate, which should further reduce the costs of compliance on non-EGU sources. With these modifications to the final rule in response to comments, the non-EGU sources subject to this rule should be able to meet the applicable control requirements established in this final rule.

The EPA also recognizes, however, that there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship. To address these limited circumstances, the EPA is finalizing a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship. The EPA has modeled the case-by-case emissions limit mechanism on case-by-case RACT requirements and certain facility-specific emissions limits under 40 CFR part 60 identified by commenters.[379] The owner or operator of a source seeking a case-by-case emissions limit must submit a request meeting specific requirements to the EPA by August 5, 2024, one year after the effective date of this final rule. The applicable emissions limits established in this final rule remain in effect until the EPA approves a source's request for a case-by-case emissions limit. Given the May 1, 2026 compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule, we encourage owners and operators of affected units who believe they must seek case-by-case emissions limits to submit their requests to the EPA before the one-year deadline for such requests, if possible, to ensure adequate time for EPA review and to install the necessary controls.

For a source requesting a case-by-case limit due to technical impossibility, the final rule requires that the request include emissions data obtained through CEMS or stack tests, an analysis

[379] For examples of case-by-case RACT provisions and source specific limits for boilers in subpart Db of the EPA's NSPS, see 40 CFR 60.44b(f); Regulations of Connecticut State Agencies section 22a–174–22e; Code of Maryland Regulations section 26.11.09.08(B)(3); and Code of Maine Rules section 096–138–3, subsection (I).

of all available control technologies based on an engineering assessment by a professional engineer or data from a representative sample of similar sources, and a recommendation concerning the most stringent emissions limit the source can technically achieve.

For a source requesting a case-by-case limit on the basis of extreme economic hardship, the final rule requires that the request include at least three vendor estimates from three separate vendors that do not have a corporate or business-affiliation with the source of the costs of installing the control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of compliance with the applicable emissions limit for that particular source would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry under this rule. In evaluating a source's request for a case-by-case limit due to extreme economic hardship, the EPA will consider the emissions reductions and costs identified in this final rulemaking (and related support documents) for other sources in the relevant industry and whether the costs of compliance for the source seeking the case-by-case limit would significantly exceed the highest representative end of the range of estimated cost-per-ton figures identified for any source in the relevant industry as discussed in section V of this document.

As discussed in section VI.A of this document, in *Wisconsin* the court held that some deviation from the CAA's 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.[380] Given these directives, the EPA cannot allow a covered source to avoid complying with the emissions limits established in this final rule unless the source can demonstrate that compliance with the limit would either be impossible as a technical matter or result in an extreme economic hardship—*i.e.,* exceed the high end of the cost-effectiveness estimates that informed the EPA's Step 3 determination of significant contribution, as discussed in section V of this document. The criteria that must be met to qualify for a case-by-case limit are designed to meet this statutory mandate.

Comment: Several commenters raised concerns about the EPA's differing applicability criteria for the various non-EGU industries. Specifically, the commenters questioned why EPA set applicability criteria for engines in Pipeline Transportation of Natural Gas and non-EGU boilers based on design capacity instead of potential to emit (PTE). Commenters also requested that the EPA allow each non-EGU category to rely on operating permits or other federally enforceable instruments to avoid being subject to the rule, such as limits to the PTE or limits on fuels used.

Response: The 100 tpy PTE threshold and comparable design capacity thresholds of 1,000 horsepower (hp) for engines and 100 mmBtu/hr for boilers are appropriate to ensure that the final rule reduces emissions from the most impactful units. The EPA finds the control technologies assumed to be installed to meet the final emissions limits would not be as readily available or cost effective for emissions units with PTE or design capacities lower than the applicability thresholds in this final rule.

With regard to the selection of design capacity thresholds for boilers and engines, the EPA finds that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines and boilers based on design capacity rather than PTE. We further explain our basis for establishing applicability thresholds based on design capacity for these two source categories in sections VI.C.1. and VI.C.5. For consistency with preexisting requirements for engines and boilers and to capture the sizes of units identified in Step 3 of our analysis, the EPA selected design capacities of 1,000 hp for engines and 100 mmBtu/hr for boilers. The EPA recognizes that these applicability thresholds captured more units than the EPA intended, particularly some low-use units. Therefore, as explained in sections VI.C.1 and VI.C.5., the EPA is establishing exemptions for low-use boilers and emergency engines, as well as new emissions averaging provisions for engines, to ensure that this final rule focuses on larger, more impactful units.

The EPA also agrees with commenters that the applicability criteria should allow for sources to rely on enforceable requirements that limit a source's PTE and is finalizing a regulatory definition of PTE that is generally consistent with the definitions of that term in the EPA's title V and NSR permit programs. *See, e.g.,* 40 CFR 51.165(a)(1)(iii), 70.2. In constructing the list of potential sources subject to the final rule, the EPA relied on available information to identify the PTE of the emissions units in the various non-EGU industries that are captured by the applicability criteria. *See Memo to Docket titled Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs.* Thus, the EPA's Step 3 analysis takes into account available information about currently enforceable emissions limits and physical and operational limitations identified in existing permits. The EPA finds it necessary to define PTE consistent with its use in the title V and NSR permit programs to ensure that the requirements of the final FIPs apply to the most impactful units identified in Step 3 of our analysis. However, to ensure that these FIPs achieve the emissions reductions necessary to eliminate significant contribution or interference with maintenance as described in this final rule, the applicability criteria for the Cement and Concrete Manufacturing, Iron and Steel and Ferroalloy Manufacturing, and Glass and Glass Product Manufacturing industries take into account only those enforceable PTE limits in effect as of the effective date of this final rule. Thus, any emissions unit in these three industries that has a PTE equal to or greater than 100 tons per year and thus meets the definition of an ''affected unit'' as of August 4, 2023, will remain subject to the applicable FIPs, without regard to any PTE limit that the emissions unit may subsequently become subject to. Each affected unit in these three industries must submit an initial notification of applicability to the EPA by December 4, 2023, that identifies its PTE as of the effective date of this final rule. Additionally, any owner or operator of an existing emissions unit that is not an affected unit as of August 4, 2023, but subsequently meets the applicability criteria (*e.g.,* due to a change in fuel use that increases the unit's PTE) will become an affected unit subject to the applicable requirements of this final rule at that time.

Comment: In responding to the EPA's request for comment on whether some non-EGU units would need to run controls required by the final FIP year-round, one commenter anticipated that control equipment would be operated as necessary to achieve applicable emissions limits, but that operational

[380] *Wisconsin,* 938 F.3d 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'').

flexibility, cost considerations and equipment longevity would warrant operation of certain control equipment on a schedule such that the equipment would not be used when unnecessary to meet emissions limits and/or outside of ozone season (*i.e.,* during winter months). The commenter further explained that flexibility in the operation of certain control equipment when unnecessary to meet emissions limits will allow for routine maintenance and repairs without requiring variances or similar exemptions from continuous operation requirements.

Response: Based on the feedback received during the public comment period, the EPA is finalizing requirements for non-EGU sources that will apply only during the ozone season, which runs annually from May to September. As discussed in the proposed rule, 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. In addition, the EPA did not receive any information during the public comment period suggesting that sources would have to run the necessary controls year-round due to the nature of those controls. We note, however, that certain emissions-control technologies, such as combustion controls that are integrated into the unit itself, would likely function to reduce NO_X emissions year-round as a practical engineering matter.

Comment: Regarding electronic reporting through the Compliance and Emissions Data Reporting Interface (CEDRI), one commenter requested that CEDRI reporting requirements be consolidated in one location rather than repeated in each section. Another commenter requested that EPA include electronic reporting requirements for MWCs and specifically require that MWCs report CEMS data to CEDRI. Another commenter requested that EPA allow for extensions of time for electronic reports due to technical glitches.

Response: To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators of non-EGU sources subject to the final FIPs, including MWCs, submit electronic copies of required initial notifications of applicability, performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the CEDRI. The final rule requires that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [381] 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 finalizing a requirement 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 a requirement that other performance evaluation results be submitted in PDF using the attachment module of the ERT. The final rule also requires that initial notifications of applicability, annual compliance reports, and excess emissions reports be submitted in PDF uploaded in CEDRI.

Furthermore, the EPA is finalizing, as proposed, provisions that allow owners and operators to seek extensions of time to submit electronic reports due to circumstances beyond the control of the owner or operator (*e.g.,* due to a possible outage in CDX or CEDRI or a *force majeure* event) in the time just prior to a report's due date, as well as provisions specifying how to submit such a claim. Public commenters supported these proposed provisions.

The EPA agrees with commenters that the CEDRI reporting requirements could be centralized and has moved the CEDRI reporting requirements to 40 CFR 52.40.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is finalizing 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 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 100 tpy PTE threshold used in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* as described in section V.B of this document.

The EPA is also modifying certain provisions in response to public comments to provide compliance flexibilities for the Pipeline Transportation of Natural Gas industry sector in order to focus emissions reduction efforts on the highest emitting units. Specifically, the EPA is finalizing an exemption for emergency engines, and establishing provisions that allow any owner or operator of an affected unit to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule.

For purposes of this rule, the EPA is clarifying and narrowing the definition of ''pipeline transportation of natural gas'' to mean the transport or storage of natural gas prior to delivery to a local distribution company custody transfer station or to a final end-user (if there is no local distribution company custody transfer station). The revised definition of this term in § 52.41(a) is consistent with the EPA's regulatory definition of ''natural gas transmission and storage segment'' in 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015).

The EPA is also adding definitions of the terms ''local distribution company'' and ''local distribution company custody transfer station'' that are consistent with the definitions found in 40 CFR 98.400 (subpart NN, Suppliers of Natural Gas and Natural Gas Liquids) and 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015), respectively.

Comment: Several commenters asked EPA to exclude emergency engines in the final rule and one commenter recommended that the EPA revise the definition of affected unit to specifically exempt emergency engines. Commenters stated that doing so would not only be consistent with other regulations applicable to stationary SI engines, but it would also be more consistent with EPA's applicability analysis, which assumes stationary SI engines will operate for 7,000 hours a year, something emergency engines are prohibited from doing by Federal regulation. Commenters also stated that emergency generators are currently exempt from requirements applicable to non-emergency RICE covered by both

[381] The ERT website is located at *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

the relevant NSPS rule (subpart JJJJ), as well as the relevant NESHAP rule (subpart ZZZZ), and that although the NSPS and NESHAP standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the ''potential to emit'' in issuing air permits for emergency RICE. One commenter asserted that emergency engines operating under other standards currently only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, that their emissions are low, and that their contribution to the ozone transport issues EPA's proposal seeks to address is negligible. Another commenter stated that the EPA has traditionally exempted emergency engines in past standards because the EPA has typically found that the use of add-on emissions controls cannot be justified due to the cost of the technology relative to the emissions reduction that would be obtained.

Response: With respect to stationary SI emergency engines, the EPA has reviewed the information submitted by the commenters and has decided to exempt such engines from the requirements of the final rule. Exemption of emergency engines is generally consistent with the EPA's treatment of emergency engines in other CAA rulemakings. *See, e.g.,* 40 CFR 63.6585(f). The EPA expects that this change from the proposed rule addresses the concerns expressed by the commenters about the requirements for stationary emergency engines.

The final rule defines emergency engines as engines that are stationary and operated to provide electrical power or mechanical work during an emergency situation. These engines are typically used only a few hours per year, and the costs of emissions control are not warranted when compared to the emissions reductions that would be achieved.

In the final rule, emergency engines are subject to certain compliance requirements on a continuous basis. Continuous compliance requirements include operating limitations that apply during non-emergency use but do not include emissions testing of emergency engines.

Comment: Several commenters raised concerns about the EPA's proposal to establish applicability criteria for engines in Pipeline Transportation of Natural Gas based on design capacity rather than PTE. Other commenters asserted that the horsepower rating of an engine does not necessarily correspond to its annual emissions and that engines with a rated capacity of more than 1,000 hp in this industry sector may operate at low load and/or infrequently and be associated with limited NO_X emissions. One commenter stated that most of the subject facilities in their state that have natural gas fired SI engines with a nameplate capacity rating of 1,000 hp or greater have annual NO_X emissions less than 100 tpy, with nearly 25 percent of them less than 25 tpy. The commenter suggested that the 1,000 hp applicability threshold would result in overcontrol. According to one commenter, the EPA has overestimated the emissions rates and operating hours of engines with a rated capacity of more than 1,000 hp and thus underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy of NO_X annually. According to this commenter, only engines much larger than 1,000 hp are likely to emit at the level EPA deemed appropriate for regulation.

Another commenter suggested that the EPA should use a 150 ton per year threshold that the commenter alleges was used in the Revised CSAPR Update rulemaking so that stationary SI engines are regulated on equal footing with EGUs and raise the 1,000 hp threshold to 2,000 hp, which according to the commenter would not sacrifice the emissions reductions to be achieved.

Response: As explained in the proposal, the EPA found that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines based on design capacity rather than PTE. For consistency with preexisting requirements for engines, the EPA selected a design capacity of 1,000 hp for engines to capture the sizes of units identified in Step 3 of our analysis. Based on the Non-EGU Screening Assessment memorandum, engines with a potential to emit of 100 tpy or greater had the most significant potential for NO_X emissions reductions. The EPA recognizes that the use of a 1,000 hp design capacity as part of the applicability criteria may capture low-use units and some units with emissions of less than 100 tons per year. However, it is also not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future. As discussed in section V of this document, we continue to find that collectively engines with a design capacity of 1,000 hp or higher in the states and industries covered by this final rule emit substantial amounts of NO_X that significantly contribute to downwind air quality problems.

However, in response to concerns raised by commenters while continuing to ensure that this rule establishes an effective emissions control program for these units that is consistent with our Step 3 determinations, the EPA is establishing a compliance alternative using facility-wide emissions averaging, which will allow facilities to prioritize emissions reductions from larger, higher-emitting units. (As previously discussed, we are also establishing an exemption for emergency engines, which also helps ensure that this final rule focuses on larger, more impactful units in this industry.) The facility-wide emissions averaging alternative is explained in the following paragraphs.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, the 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 (ppmv), 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 final FIP as well.

Based on the available information for this industry, including applicable State and local air agency rules and active air permits issued to sources with similar engines, the EPA is finalizing the following emissions limits for stationary SI engines in the covered states. Beginning in the 2026 ozone season and in each ozone season thereafter, the following emissions limits apply, based on a 30-day rolling average emissions rate during the ozone season:

TABLE VI.C–1—SUMMARY OF FINAL NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

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

The EPA anticipates that, in some cases, affected engines will need to install NO_X controls to comply with the final emissions limits in Table VI.C–1. The emissions limits for four stroke rich burn engines, four stroke lean burn engines and two stroke lean burn engines are designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines; installing SCR on existing four stroke lean burn engines; and retrofitting layer combustion on existing two stroke lean burn engines as identified in the Final Non-EGU Sectors TSD. Sources have the flexibility to install any other control technologies that enable the affected units to meet the applicable emissions limit on a continuous basis.

The EPA is establishing provisions that allow any owner or operator of an affected unit in the Pipeline Transportation of Natural Gas Industry to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. These provisions will provide some flexibility to owners and operators of affected units to determine which engines to control and at what level, so long as the average emissions across all covered units, on a weighted basis, meet the applicable emissions limits for each engine type. This approach allows facilities to target the most cost-effective emissions reductions and to avoid installing controls on equipment that is infrequently operated.

We provide a more detailed discussion of the basis for the final emissions limits and the anticipated control technologies to be installed in the Final Non-EGU Sectors TSD.

Four Stroke Rich Burn and Four Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit is appropriate for four stroke rich burn engines 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. The EPA also requested comment on whether a lower or higher emissions limit is appropriate for four stroke lean burn engines.

Comment: One commenter stated that the limits as proposed were not technically feasible in all circumstances. The commenter explained that its company has 150 four stroke rich burn engines in its fleet and that some of those engines cannot achieve the proposed 1.0 g/hp-hr limit even with both NSCR and layered combustion due to the vintage design of the individual cylinder geometry and the fact that most of these engines are not in production today, which limits availability of parts and retrofit technologies. The commenter asserted that 10 of its four stroke rich burn engines have all available controls on them and half of those still exceed the proposed limits. The commenter estimated that 10 of its four stroke lean burn engines would require SCR to meet the 1.5 g/hp-hr limit and that this control installation would require custom retrofit due to the age of these engines. Furthermore, the commenter stated that if current limits are not achievable in all circumstances, then lower limits are likewise impossible for four stroke rich burn engines and four stroke lean burn engines in even more circumstances. The commenter stated that the technical feasibility of installing controls on any single existing engine varies and depends, in part, on site-specific and engine-specific considerations such as space for the installation of the control, the availability of sufficient power, the emissions reductions required to meet the applicable standards, and the vintage, make, and model of a particular engine. Another commenter recommended tightening the proposed emissions standards for four stroke lean burn engines to an emissions limit similar to Colorado's limit of 1.2 g/hp-hr. A third commenter noted that the District of Columbia Department of Energy and Environment has NO_X emissions limits for both rich- and lean burn engines burning natural gas at 0.7 g/hp-hr.

Response: The EPA is finalizing the emissions limits for both four stroke rich burn engines and four stroke lean burn engines as proposed but also establishing alternative compliance provisions and criteria for establishing case-by-case alternative emissions limits in response to the concerns raised by commenters. NSCR can achieve NO_X reductions of 90 to 99 percent, and engines in California, Colorado, Pennsylvania and Texas have achieved the emissions limits that the EPA had proposed. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 1.0 g/hp-hr emissions limit for four stroke rich burn engines and a 1.5 g/hp-hr emissions limit for four stroke lean burn engines. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

To address the concerns raised by some commenters that not all engines may be able to achieve the emissions limits as proposed due to engine vintage and technical constraints, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. An approved Facility-Wide Averaging Plan would allow the owner or operator of the facility to identify the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs). In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. The provisions governing case-by-case alternative limits are explained in more detail in section VI.C of this document.

Two Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit would be achievable with layered combustion alone for the two stroke lean burn engines covered by this final rule. The

EPA also sought comment on whether these engines could install additional control technology at or below the marginal cost threshold to achieve a lower emissions rate.

Comment: Commenters did not specifically address whether a lower emissions limit would be achievable with layered combustion alone at two stroke lean burn engines. However, one commenter stated that older two stroke lean burn engines generally would not be able to achieve the proposed NO_X emissions limits. The commenter stated that conversion kits are available for several models that can reduce emissions but that such kits are not made for all models, especially older stationary engines. Commenters further stated that where conversion kits are not available, a company would likely have no choice but to replace the older four stroke or two stroke stationary engines, typically at a cost of $2 million to $4 million each.

Two commenters stated that they are required by their state agency to have RACT, BACT, or BART controls, at minimum. Commenters stated that requiring additional controls at facilities already equipped with RACT, BACT or BART control technologies would not achieve the anticipated emissions reductions due to operational factors inherent in the preexisting and pre-controlled equipment and that the achievability of targeted control levels is highly dependent upon a number of variables at each facility.

Another commenter suggested that the EPA set lower limits for two stroke lean burn engines similar to the OTC-recommended limits in the range of 1.5–2.0 g/hp-hr.

Response: Information currently available to the EPA indicates that the amount of emissions reductions achievable with layered combustion controls 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 up to 80 percent to comply with a 3.0 g/hp-hr emissions limit. The EPA has found that engines in California, Colorado, Pennsylvania and Texas have achieved these emissions rates. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 3.0 g/hp-hr emissions limit for two stroke lean burn engines. Although some affected units may be able to achieve a lower emissions rate, we find that a 3.0 g/hp-hr emissions limit generally reflects a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. As explained in the proposed rule and expressed by public commenters, if the EPA were to establish an emissions limit lower than 3.0 g/hp-hr, some two stroke lean burn engines would not be able to meet the emissions limit with the installation of layered combustion control alone. In that case, the lower limit might require the installation of SCR, which the EPA did not find to be cost-effective for two stroke lean burn engines in its Step 3 analysis.[382] The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for this emissions limit.

In response to commenters' concerns about the difficulties involved in retrofitting or replacing older stationary engines to achieve the EPA's proposed emissions limit, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. However, in the context of older or ''vintage,'' high-emitting engines in this industry for which commenters claim emissions control technology retrofit is not feasible, the Agency anticipates taking into consideration the cost associated with alternative compliance strategies, such as replacement with new, far more efficient and less polluting engines, in evaluating claims of extreme economic hardship.

Facility-Wide Averaging Plan

The EPA is finalizing regulatory text that provides for an emissions limit compliance alternative using facility-level emissions averaging. An approved Facility-Wide Averaging Plan will allow the owner or operator of the facility to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control). So long as all of the emissions units covered by the Facility-Wide Averaging Plan collectively emit less than or equal to the total amount of NO_X emissions (in tons per day) that would be emitted if each covered unit individually met the applicable NO_X emissions limitations, the covered units will be in compliance with the final rule. Under this alternative compliance option, facilities have the flexibility to prioritize emissions reductions from larger, dirtier engines.

Comment: Several commenters recommended that the EPA promulgate emissions averaging provisions, as it did in the 2004 NO_X SIP Call Phase 2 rule (69 FR 21604), in which the EPA evaluated and supported reliance on emissions averaging for RICE in the Pipeline Transportation of Natural Gas industry sector. The commenter stated that the EPA's guidance to states on developing an appropriate SIP in response to the SIP Call provided companies the ''flexibility'' to use a number of control options, as long as the collective result achieved the required NO_X reductions, and that many states built their revised SIPs around the emissions averaging approach addressed in this guidance document.[383] One commenter recommended that the EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company. Another commenter asserted that units of certain vintages and units from certain manufacturers will not be able to meet the emissions rate limits the EPA had proposed. The commenter claimed that, absent a system based on source-specific emissions limits, emissions averaging is one of the only practical mechanisms for addressing these challenges.

One commenter stated that it had evaluated the cost of controls for engines in its fleet and that the variety in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program. Another commenter advocated for an emissions averaging plan that would allow an engine-by-engine showing of economic infeasibility to ensure a cost-effective application of the emissions standards, a reduced impact on natural gas capacity, and a means for addressing the problem presented by achieving

[382] 87 FR 20036, 20143 (noting that an emissions limit below 3.0 g/hp-hr may require some two stroke lean burn engines to install additional controls beyond the EPA's cost threshold).

[383] The commenter refers to an August 22, 2002 memorandum from Lydia N. Wegman, Director, EPA, Air Quality Strategies and Standards Division to EPA Air Division Directors, entitled ''State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NO_X)—Stationary Reciprocating Internal Combustion Engines.''

compliance on engines that are technically impossible to retrofit.

One commenter stated that the EPA should also consider allowing companies to choose a mass-based alternative that would ensure emissions reductions align with the tons per year reductions upon which the EPA based its significant contribution and over-control analyses.

Response: Based upon the EPA's 2019 NEI emissions inventory data, the EPA estimates that a total of 3,005 stationary SI engines are subject to the final rule. The EPA recognizes that many low-use engines are captured by the 1,000 hp design capacity applicability threshold. In the process of reviewing public comments, the EPA reviewed emissions averaging plans found in state air quality rules for Colorado, Illinois, Louisiana, New Jersey, and Tennessee.[384] Based on these additional reviews, the EPA is finalizing in § 52.41(c) of this final rule an emissions limit compliance alternative using facility-level emissions averaging. Emissions averaging plans will allow facility owners and operators to determine how to best achieve the necessary emissions reductions by installing controls on the affected engines with the greatest emissions reduction potential rather than on units with lower actual emissions where the installation of controls would be less cost effective. The final rule defines ''facility'' consistent with the definition of this term as it generally applies in the EPA's NSR and title V permitting regulations,[385] with one addition to make clear that, for purposes of this final rule, a ''facility'' may not extend beyond the boundaries of the 20 states covered by the FIP for industrial sources, as identified in § 52.40(b)(2). Because a facility cannot extend beyond this geographic area, a Facility-Wide Averaging Plan also cannot extend beyond the 20-state area covered by the FIP.

To estimate the number of facilities that may take advantage of the Facility-Wide Averaging Plan provisions, and the number of affected units that would install controls under such an emissions averaging plan, the EPA conducted an analysis on a subset of the estimated 3,005 stationary IC engines subject to the final rule. The EPA evaluated the reported actual NO_X emissions data in tpy from a subset of facilities in the covered states using 2019 NEI data for stationary IC engines with design capacities of 1,000 hp or greater. The EPA then identified a number of facilities that have more than one affected engine, calculated each facility's emissions ''cap'' as the total NO_X emissions (in tpy) allowed facility-wide based on the unit-specific NO_X emissions limits applicable to all affected units at the facility, and identified a number of higher-emitting engines at each facility that were candidates for having controls installed. For engines that EPA identified were likely to install controls, the EPA assumed that four stroke rich burn engines, four stroke lean burn engines, and two stroke lean burn engines could achieve a NO_X emissions rate of 0.5 g/hp-hr with the installation of SCR based on data obtained from the Ozone Transport Commission report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012). For the remaining engines identified as uncontrolled, the EPA assumed a NO_X emissions rate of 16 g/hp-hr for all engine types. Thus, under the assumed averaging scenarios, engines with controls installed would achieve emissions levels below the emissions limits in the final rule and would offset the higher emissions from the remaining uncontrolled units.

The EPA then calculated the total facility-wide emissions (in tpy) under various assumed averaging scenarios and compared those totals to each facility's calculated emissions cap (in tpy) to estimate the number of affected units at each facility that would need to install controls to ensure that total facility-wide emissions remained below the emissions cap. Based on these analyses, the EPA found that emissions averaging should allow most facilities to install controls on approximately one-third of the engines at their sites, on average, while complying with the applicable NO_X emissions cap on a facility-wide basis. For a more detailed discussion of the EPA's analysis and related assumptions, see the Final Non-EGU Sectors TSD.

The Facility-Wide Averaging Plan provisions that the EPA is finalizing provide the flexibility needed to address the concerns about the costs of emissions control installations for certain stationary SI engines, by allowing facility owners and operators to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control).

An owner or operator of a facility containing more than one affected unit may elect to use an EPA-approved Facility-Wide Averaging Plan as an alternative means of compliance with the NO_X emissions limits in § 52.41(c). The owner or operator of such a facility must submit a request to the EPA that, among other things, specifies the affected units that will be covered by the plan, provides facility and unit-level identification information, identifies the facility-wide emissions ''cap'' (in tpd) that the facility must comply with on a 30-day rolling average basis, and provides the calculation methodology used to demonstrate compliance with the identified emissions cap. The EPA will approve a request for a Facility-Wide Averaging Plan if the EPA determines that the facility-wide emissions total (in tpd), based on a 30-day rolling emissions average basis during the ozone season, is less than the emissions cap (in tpd) and the plan establishes satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, and recordkeeping requirements.

Compliance Assurance Requirements

The EPA is requiring owners and operators of affected units to conduct annual performance tests in accordance with 40 CFR 60.8 to demonstrate compliance with the NO_X emissions limit in this final rule. The EPA is also requiring owners and operators to monitor and record hours of operation and fuel consumption and to use continuous parametric monitoring systems to demonstrate ongoing compliance with the applicable NO_X emissions limit. For example, owners and operators of engines that utilize layered combustion controls will 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, owners and operators must monitor and record parameters such as inlet temperature to the catalyst

[384] *See* Code of Colorado Regulations, Regulation Number 7 (5 CCR 1001–9), Part E, Section I.D.5.c., Illinois Administrative Code, Title 35, Section 217.390, Louisiana Administrative Code, Title 33, Section 2201, New Jersey Administrative Code, Title 7, Chapter 27, Section 19.6, and Rules of the Tennessee Dept. of Environment and Conservation, Rule 1200–03–27–.09.

[385] See 40 CFR 51.165(a)(1)(ii)(A), 51.166(b)(6)(i), and 52.21(b)(6)(i) (defining ''building, structure, facility, or installation'' for Nonattainment New Source Review and Prevention of Significant Deterioration permits) and *Natural Resources Defense Council* v. *EPA,* 725 F.2d 761 (D.C. Cir. 1984) (vacating and remanding EPA's categorial exclusion of vessel activities from this definition); see also 40 CFR 70.2 (defining ''major source'' for title V operating permits).

and pressure drop across the catalyst. For affected engines that meet the certification requirements of § 60.4243(a), however, the facility-wide emissions calculations may be based on certified engine emissions standards data pursuant to § 60.4243(a), instead of performance tests.

In calculating the facility-wide emissions total during the ozone season, affected engines covered by the Facility-Wide Averaging Plan must be identified by each engine's nameplate capacity in horsepower, its actual operating hours during the ozone season, and its emissions rates in g/hp-hr from certified engine data or from the most recent performance test results for non-certified engines according to § 52.41(e).

Comment: Several commenters stated that semi-annual performance testing would not be appropriate due to its high costs and limited benefits. One commenter proposed a ''step-down'' testing alternative that could be conducted after establishing an engine's initial compliance via performance testing. Under this approach, owners and operators would conduct one performance test and would only need to conduct a second performance test within a given year if the first performance test demonstrated that an engine was not meeting the applicable emissions standards.

Another commenter asserted that to test all of its 950 units, a minimum of 12 months would be needed rather than the six months the EPA had proposed to provide (or five months if the EPA would require one of the semi-annual tests to be conducted during the ozone season). The commenter stated that the EPA had accounted for these operational realities in the past and that under the NSPS and NESHAP, testing is generally required only once for every 8,760 hours of run time. The commenter asserted that there is no reason to require more frequent testing than those required under the NSPS and NESHAP.

Several commenters requested that the EPA allow for reduction in the frequency of testing to once every two years if testing shows that NO_X emissions are no more than 75 percent of permitted NO_X emissions limits. In addition, several commenters stated that since the rule is intended to address the ozone season, a single, annual test is more feasible than semi-annual testing and reporting.

Response: For the stationary SI engines subject to this final rule, the EPA is revising the frequency of required performance tests from a semi-annual basis to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the 5-month ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to determine continuous compliance during the ozone season. The EPA also agrees with commenters that the annual tests required under the final rule need not occur during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: Commenters generally stated that requiring CEMS would add an unnecessary cost and complexity, would provide no emissions reduction benefit for the affected units the proposed FIP intends to control and are not warranted due to the availability of other established methods of compliance assurance, such as parametric monitoring and periodic testing. One commenter stated that requiring CEMS would add unnecessary CEMS testing obligations. Another commenter stated that the costs associated with CEMS and frequent performance testing on affected RICE would be as much, if not more, than the costs associated with installation and operation of some of the control technologies EPA has considered in setting the proposed emissions limits. According to one commenter, the EPA has traditionally agreed with this viewpoint on the high cost of CEMS, as most stationary engines are not currently required under the NSPS or NESHAP to install or operate CEMS.

Another commenter stated that in addition to cost, there are other barriers to installing CEMS on RICE across the Pipeline Transportation of Natural Gas industry. Many RICE in the Pipeline Transportation of Natural Gas industry are located at remote, unstaffed locations, meaning that there would be no staff available to respond and react to communication or alarms from CEMS.

Response: The EPA acknowledges the costs associated with the installation and maintenance of CEMS at affected units in the Pipeline Transportation of Natural Gas industry and agrees that it is not necessary to require CEMS for purposes of compliance with the requirements of this final rule for this industry. Accordingly, the EPA is not finalizing requirements for affected units in this industry sector to install or operate CEMS. Instead, the EPA is requiring parametric monitoring protocols, as described earlier, coupled with an annual performance test, which will ensure that the emissions limits are legally and practically enforceable on a continuous basis, and that data are recorded, reported, and can be made publicly available, ensuring the ability of state and Federal regulators and other persons under CAA sections 113 and 304 to enforce the requirements of the Act.

2. Cement and Concrete Product Manufacturing

Applicability

For cement kilns in the Cement and Cement Product Manufacturing industry, the EPA is finalizing the proposed applicability provisions without change. The affected units in this industry are cement kilns that emit or have a PTE of 100 tpy or more of NO_X. The EPA received comments regarding the definition of PTE, which we address in section VI.C, but no comments concerning the 100 tpy PTE threshold for applicability purposes.

Emissions Limitations and Rationale

As explained in the proposal, the EPA based the proposed emissions limits for cement kilns on the types of limits being met across the nation in RACT NO_X rules, NSPS, air permits, and consent decrees. Based on these requirements, the EPA proposed emissions limits in the form of mass of pollutant emitted (in pounds) per kiln's clinker output (in tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced during a 30-operating day rolling average period. Further, the EPA proposed specific emissions limits for long wet, long dry, preheater, precalciner, and combined preheater/precalciner kilns. The EPA also proposed a daily source cap limit that would apply to all units at a facility. Based on information received from public comments, the EPA is removing the daily source cap limit but finalizing the emissions limits as proposed in all other respects, as shown in Table VI.C–2.

TABLE VI.C–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	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

Comment: Numerous commenters raised concerns about designing a source cap limit based on average annual production in tons of clinker and kiln type. Commenters stated that the source cap limit equation as used in a prior action applied to long wet and dry preheater-precalciner or precalciner kilns and did not include other kiln types. Commenters expressed concern that the CAP2015 Ozone Transport equation the EPA proposed in this rule could lead to artificially low and restrictive daily emissions caps for facilities that experienced a temporary decrease in production due to the COVID–19 pandemic, during the historical three-year period proposed for use in determining the NO_X source cap. Also, commenters expressed concern that the proposed daily emissions cap limit originated as a local or regional limit for a single county and would not be appropriate for national application without further evaluation taking into account the specific characteristics of cement kilns in other states. One commenter suggested more stringent emissions limits than those the EPA had proposed for individual kiln types.

Response: The EPA is not finalizing the proposed daily source cap limit as the Agency agrees with the commenters that this proposed limit would be unnecessarily restrictive and was based on a formula that did not include all kiln types. Given the unusual reduction in cement production activities due to the COVID–19 pandemic, production rates during the 2019–2021 period are not representative of cement plants activities generally. Accordingly, use of the proposed daily source cap limit would result in an artificially restrictive NO_X emissions limit for affected cement kilns, particularly when this sector operates longer hours during the spring and summer construction season. With respect to those comments supporting more stringent emissions limits than those the EPA proposed for individual kiln types, we disagree given the significant differences among different kilns in design, configuration, age, fuel capabilities, and raw material composition. The EPA finds that the ozone season emissions limits for individual kiln types listed in Table VI.C–2 will achieve the necessary emissions reductions for purposes of eliminating significant contribution as defined in section V and is, therefore, finalizing these emissions limitations without change.

Comment: One commenter supported retirement of existing long wet kilns and replacement of these kilns with modern kilns. Other commenters opposed the phase out and retiring of these kilns, stating that many of the screened kilns have SNCR already installed and questioning whether replacement of existing long wet kilns is cost-effective. Some commenters also stated that according to EPA's ''NO_X Control Technologies for the Cement Industry, Final Report,'' SNCR is not an appropriate NO_X control technique for long wet kilns.

Response: The EPA appreciates the challenges identified by commenters, such as site-specific technical evaluation and review and significant capital investment associated with undertaking kiln conversions or to install new kilns and is not finalizing any requirements to replace existing long wet kilns in this rule.

Comment: Several commenters expressed concern about the supply chain issues relevant to the procurement, design, construction, and installation of control devices, as well as securing related contracts, for the cement industry, particularly when cement sources will be competing with the EGU and other industrial sectors for similar services. One commenter stated that many preheater/precalciner kilns are already equipped with SNCR and that one facility not equipped with SNCR is already meeting NO_X emissions levels of 1.95 lb/ton of clinker or less. The commenter stated that the EPA should revise its assessment of potential NO_X reductions and cost estimates by accurately accounting for existing operating efficiencies and control devices at cement kilns.

Response: The EPA's response to comments on the time needed for installation of controls for non-EGU sources is provided in section VI.A. Regarding the comment that certain facilities may already have SNCR control technology installed, we recognize that many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

Compliance Assurance Requirements

The EPA received no comments on the proposed test methods and procedures provisions for the cement industry. Therefore, we are finalizing the proposed test methods and procedures for affected cement kilns without change.

Comment: Commenters generally supported requiring performance testing or installation of CEMS on affected cement kilns. Some commenters suggested that no performance testing should be required and others suggested that performance testing should only be required when a title V permit is due for renewal (every 5 years). One commenter suggested requiring sources to conduct stack tests during the ozone season.

Response: Affected kilns that operate a NO_X CEMS may use CEMS data consistent with the requirements of 40 CFR 60.13 in lieu of performance tests to demonstrate compliance with the requirements of this final rule. For affected kilns subject to this final rule that do not employ NO_X CEMS, the EPA is adjusting the performance testing frequency and requiring kilns to conduct a performance test on an annual basis during a given calendar year.[386] The EPA finds that annual performance testing and recordkeeping of cement production and fuel consumption during the ozone season will assure compliance with the emissions limits during the ozone season (May through September) each year for purposes of this rule. The required annual performance test may be performed at any time during the calendar year. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: One commenter stated that CEMS has been used successfully at its facility. Another commenter explained that the inside of a cement kiln is an extremely challenging environment for making any kind of continuous measurement as temperatures are high, and there is a lot of dust and tumbling clinker can damage in situ measuring instruments.

Response: The majority of cement kilns in the United States are already equipped with CEMS. However, in response to commenters concerns regarding the installation of CEMS, the EPA is finalizing alternative compliance requirements in lieu of CEMS. Owners or operators of affected emissions units without CEMS installed must conduct annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. Specifically, owners or operators of affected units without CEMS must monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is establishing emissions control requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to reheat furnaces that directly emit or have the potential to emit 100 tpy or more of NO_X. After review of all available information received during public comment, the EPA has determined that there is sufficient information to determine that low-NO_X burners can be installed on reheat furnaces. As explained further in the Final Non-EGU Sectors TSD, the EPA identified 32 reheat furnaces with low-NO_X burners installed and has concluded that low-NO_X burners are a readily available and widely implemented emissions reduction strategy.[387] This rule defines reheat furnaces to include all furnaces used to heat steel product—metal ingots, billets, slabs, beams, blooms and other similar products—to temperatures at which it will be suitable for deformation and further processing.

Comment: Several industry commenters requested that the EPA not include certain iron and steel emissions units—including blast furnaces, basic oxygen furnaces (BOFs), ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces (EAFs)—in the final rule as proposed due to, among other things, the uniqueness of each emissions unit, various design-related challenges, and expected impossibility of successful implementation of add-on NO_X control technology. Commenters expressed concern about requirements to install SCR for all iron and steel units for which the EPA proposed emissions limits. The commenters stated that iron and steel units had not installed SCR except in a few rare instances for experimental reasons and that SCR technology was not readily available or known for the iron and steel industry, unlike the control technologies expected to be installed in other non-EGU industries. Furthermore, commenters stated that SCR had not been applied for RACT, BACT, or LAER purposes on iron and steel units.

Response: In light of the comments we received on the complex economic and, in some cases, technical challenges associated with implementation of NO_X control technologies on certain emissions units in this sector, the EPA is not finalizing the proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

The EPA is aware of many examples of low-NO_X technology utilized at furnaces, kilns, and other emissions units in other sectors with similar stoichiometry, including taconite kilns, blast furnace stoves, electric arc furnaces (oxy-fuel burners), and many other examples at refineries and other large industrial facilities. The EPA anticipates that with adequate time, modeling, and optimization efforts, such NO_X reduction technology may be achievable and cost-effective for these emissions units in the Iron and Steel Mills and Ferroalloy Manufacturing sector as well. However, the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NO_X controls, including SCR or other NO_X control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry. We provide a more detailed discussion of the economic and technical issues associated with implementation of NO_X control technologies on these emissions units, including information provided by commenters, in section 4 of the Final Non-EGU Sectors TSD.

Reheat furnaces are the only type of emissions unit within the Iron and Steel Mills and Ferroalloy Manufacturing industry that this final rule applies to. Low-NO_X controls (*e.g.,* low-NO_X burners) are a demonstrated control technology that many reheat furnaces have successfully employed.

Comment: One commenter claimed that the proposed definition of ''reheat furnaces'' is overly vague and requested that the EPA amend the definition. Specifically, the commenter asserted that the EPA's proposed definition does not indicate what counts as ''steel product'' and whether this includes only products that have already been manufactured into some form before being introduced to a reheat furnace, or whether it also includes steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product. The commenter referenced the definition of reheat furnaces in Ohio's RACT regulations as an example to consider.

Response: In response to these comments, the EPA is finalizing a definition of reheat furnaces that is consistent with the definition in Ohio's NO_X RACT regulations. *See* Ohio Admin. Code 3745–110–01(b)(35) (March 25, 2022). Specifically, the EPA is defining reheat furnaces to mean ''all furnaces used to heat steel product, including metal ingots, billets, slabs, beams, blooms and other similar products, to temperatures at which it will be suitable for deformation and further processing.''

[386] 40 CFR 63.11237 ''Calendar year'' defined as the period between January 1 and December 31, inclusive, for a given year.

[387] See Final Non-EGU Sectors TSD, Section 4.

Emissions Control Requirements, Testing, and Rationale

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 is finalizing requirements for each facility with an affected reheat furnace to design, fabricate and install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by at least 40 percent by volume, and to conduct performance testing before and after burner installation to set emissions limits and verify emissions reductions from pre-installation emissions rates. Each low-NO_X burner shall be designed to achieve at least 40 percent NO_X reduction from existing reheat furnace exhaust emissions rates. Each facility with an affected reheat furnace shall, within 60 days of conclusion of the post-installation performance test, submit testing results to the EPA to establish NO_X emissions limits over a 30-day rolling average. Each proposed emissions limit must be supported by performance test data and analysis.

In evaluating potential 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 emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hour) (*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. Regulated iron and steel facilities, including facilities operating reheat furnaces in this sector, routinely monitor and keep track of production in terms of tons of steel produced per hour (heat rate) as it pertains to each facility's rate of iron and steel production. Several facilities, including Steel Dynamics, Columbia, Indiana, Cleveland-Cliffs, Cleveland, Ohio, and Cleveland-Cliffs, Burns Harbor, Indiana, are already operating various types of reheat furnaces with low-NO_X burners and achieving emissions rates as low as 0.11 lb/mmBtu of NO_X. The EPA identified at least nine reheat furnaces with a PTE greater than 100 tpy, including slab, rotary hearth, and walking beam furnaces, that have installed low-NO_X burners and are achieving various emissions rates.[388]

Due to variations in the emissions rates that different types of reheat furnaces can achieve, the EPA is not finalizing one emissions limit for all reheat furnaces and is instead requiring the installation of low-NO_X burners or equivalent low-NO_X technology designed to achieve a minimum 40 percent reduction from baseline NO_X emission levels, together with source specific emissions limits to be set thereafter based on performance testing. Specifically, the final rule requires that each owner or operator of an affected unit submit to the EPA, within one year after the effective date of the final rule, a work plan that identifies the low-NO_X burner or alternative low-NO_X technology selected, the phased construction timeframe by which the owner or operator will design, install, and consistently operate the control device, an emissions limit reflecting the required 40 percent reduction in NO_X emission levels, and, where applicable, performance test results obtained no more than five years before the effective date of the final rule to be used as baseline emissions testing data providing the basis for the required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing to establish baseline emissions data.

Comment: One commenter stated that the standard practice for setting NO_X limits for iron and steel sources often requires consideration of site or unit-specific issues. Similarly, another commenter stated that a single limit would not provide an adequate basis for establishing NO_X emissions limits that will universally apply to multiple, unique facilities. The same commenter stated that NO_X reduction in certain furnaces is routinely achievable by combustion controls or measures other than SCR.

Response: The EPA acknowledges the difficulty in crafting one emissions limit for multiple iron and steel facilities and units of varying size, age, and design, in light of the unique issues associated with varying unit types in this particular industry. We also acknowledge that in some cases, reheat furnaces are equipped with recently installed, high-efficiency low-NO_X burners. Many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

The EPA is finalizing requirements for reheat furnaces to install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by 40 percent by volume, and to perform pre- and post-installation performance testing at exhaust outlets to determine rate-based emissions limits for reheat furnaces in lb/hour, lb/mmBtu, or lb/ton on a rolling 30-operating day average. Owners and operators of affected units must also monitor NO_X emissions from reheat furnaces using CEMS or annual performance testing and recordkeeping and operate low-NO_X burners in accordance with work practice standards set forth in the regulatory text. Due to the many types of emissions units within the Iron and Steel Mills and Ferroalloy Manufacturing industry, and the limited information available at this time regarding NO_X control options that are achievable for these units, the EPA is finalizing requirements only for reheat furnaces at this time.

Comment: Commenters expressed concern that the proposed emissions limits identified both a 3-hour and a 30-day averaging time for the same limits and requested that the EPA clarify the averaging time in the final rule. Commenters requested that the EPA finalize limits with a 30-day averaging time consistent with the requirements for other non-EGU industries.

Response: In determining the appropriateness of 30-day rolling averaging times, the 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. The EPA also reviewed

[388] Specifically, through a review of title V permits, the EPA identified reheat furnaces with low-NO_X burners installed at Steel Dynamics in Columbia City, Indiana (two furnaces), Steel Dynamics in Butler, Indiana (one furnace), Cleveland Cliffs in Burns Harbor, Indiana (four furnaces), Cleveland Cliffs in East Chicago, Indiana (one furnace), and Cleveland Cliffs in Cleveland, Ohio (one furnace). For a further discussion of the limits and information on these facilities, see the Final Non-EGU Sectors TSD.

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 and the information provided by public commenters, the EPA is requiring a 30-operating day rolling average period as the averaging timeframe for reheat furnaces. 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 providing the flexibility needed to address fluctuations in operations and production.

Compliance Assurance Requirements

The EPA is finalizing requirements for each owner or operator of an affected unit in the Iron and Steel Mills and Ferroalloy Manufacturing industry to use CEMS or annual performance tests and continuous parametric monitoring to determine compliance with the 30-day rolling average emissions limit during the ozone season. Facilities choosing to use CEMS must perform an initial RATA per CEMS and maintain and operate the CEMS according to the applicable performance specifications in 40 CFR part 60, appendix B. Facilities choosing to use testing and continuous parametric monitoring for compliance purposes must use the test methods and procedures in 40 CFR part 60, appendix A–4, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures.

Comment: Several commenters raised concerns with the requirement to install and operate CEMS to monitor NO_X emissions. Commenters cited the high relative costs of installing CEMS, especially for smaller units with lower actual emissions, and the complexities with installing CEMS on mobile reheat furnaces. Further, commenters explained that due to the unique configuration of certain facilities, it would be impossible for a CEMS to differentiate emissions from a reheat furnace and other units, like waste heat boilers. As an alternative to CEMS, commenters requested that the EPA finalize similar monitoring and recordkeeping requirements as proposed for the Cement and Concrete Product Manufacturing industry in the proposed rule, which allow for CEMS or performance testing and recordkeeping. Commenters explained that for reheat furnaces that are natural gas-fired, emissions can be tracked by relying on vendor guarantees and emissions factors and natural gas throughput.

Response: The EPA reviewed comments received from the industry regarding their concerns of affected units within the iron and steel mills and ferroalloy manufacturing sector being required to demonstrate compliance through CEMS. The EPA acknowledges the cost associated with the installation and maintenance of CEMS to demonstrate compliance with the finalized emissions standards for reheat furnaces. In this final rule, the EPA is revising the compliance assurance requirements to provide flexibility to owners or operators of affected units. Compliance may be demonstrated through CEMS or annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. For sources relying on annual performance tests and continuous parametric monitoring to assure compliance, the EPA is requiring that sources keep records of production and fuel usage during the ozone season to assure compliance with the emissions limits on a 30-day rolling average basis. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is finalizing regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to furnaces that directly emit or have a PTE of 100 tpy or more of NO_X. For this industry, the EPA is finalizing the proposed applicability provisions without change.

Comment: One commenter requested that the applicability threshold for glass manufacturing furnaces should be based on a unit's design production capacity instead of the proposed applicability criteria (*i.e.,* units that directly emit or have the potential to emit 100 TPY or more of NO_X). The commenter stated that the production capacity for glass manufacturing furnaces is a more relevant basis for applicability and would focus the EPA analysis on cost-effective regulations.

Response: During the EPA's development of the proposed emissions limits, the EPA reviewed the applicability provisions in various state RACT NO_X rules, air permits, consent decrees, and Federal regulations applicable to glass manufacturing furnaces. Most of these applicability provisions were expressed in terms of actual emissions or PTE. Given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA finds that applicability criteria based on emissions or potential to emit are the most appropriate way to capture higher-emitting glass manufacturing furnaces that contribute NO_X emissions to downwind receptors.

Emissions Limitations and Rationale

The EPA is finalizing the proposed NO_X emissions limits for furnaces within the Glass and Glass Product Manufacturing industry, except that for flat glass manufacturing furnaces the EPA is finalizing an emissions limit slightly lower than the limit we had proposed, based on a correction to a factual error in our proposal. For further discussion of the basis for the form and level of the final emissions limits, see the proposed rule, 87 FR 20036, 20146 (April 6, 2022) (discussing EPA review of state RACT rules, NSPS, and other regulations applicable to the Glass and Glass Product Manufacturing industry). Several comments supported the EPA's effort to regulate sources within the Glass and Glass Product Manufacturing industry but also requested that the EPA establish more stringent emissions limits for this industry.

Comment: One commenter stated that NO_X emissions from the Glass and Glass Product Manufacturing industry are not currently subject to any Federal NSPS and that the industry is expected to grow in the coming years. The commenter stated that while the EPA's proposed limits on glass furnaces fell within the ranges of limits required by various states and air districts, they fell at the weakest levels within those ranges. For example, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for container glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1 to 4 lb/ton. Similarly, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for pressed/blown glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1.36 to 4 lb/ton, and that EPA had proposed a 9.2 lb/ton NO_X emissions limit for flat glass manufacturing furnaces, while state NO_X emissions limits for these emissions units range from 5–9.2 lb/ton. The commenter urged the EPA to establish emissions limits lower than those the EPA had proposed.

Response: The EPA is finalizing the emissions limits for affected units in the glass and glass product manufacturing industry as proposed for all but flat glass manufacturing furnaces, for which the EPA is finalizing a slightly lower emissions limit to reflect a correction to a factual error in our proposal. During the EPA's development of the proposed emissions limits, the EPA reviewed the control requirements or recommendations and related analyses in various RACT NO_X rules, air permits, Alternative Control Techniques (ACT) documents, and consent decrees to determine the appropriate NO_X emissions limits for the different types of glass manufacturing furnaces. Based on these reviews and given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA has concluded that it is appropriate to finalize the emissions limits for this industry as proposed, except for the limit proposed for flat glass manufacturing furnaces. For flat glass manufacturing furnaces, the EPA had proposed a NO_X emissions limit of 9.2 pounds (lbs) per ton of glass pulled but is finalizing a limit of 7.0 lbs/ton of glass pulled on a 30-day rolling average basis. This is based on our review of specific state RACT NO_X regulations that contain a 9.2 lbs/ton limit averaged over a single day but contain a 7.0 lbs/ton limit over a 30-day averaging period. This change aligns the final limit for flat glass manufacturing furnaces with the correct averaging time and is consistent with both the state RACT regulations that we reviewed [389] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule.

The EPA acknowledges that NO_X emissions from some glass manufacturing furnaces are subject to control under other regulatory programs, such as those adopted by states to meet CAA RACT requirements, and that some of these programs have implemented more stringent emissions limits than those the EPA is finalizing in these FIPs. However, as noted in the preamble to the proposed rule and related TSD, many OTR states do not establish specific NO_X emissions limits for glass manufacturing sources.[390] *See* 87 FR 20146. In addition to state RACT rules, air permits, ACT documents, and consent decrees applicable to this industry, the EPA reviewed reports and recommendations from the National Association of Clean Air Agencies (NACAA), the European Union Commission, and EPA's Menu of Control Measures (MCM) to identify potentially available control measures for reducing NO_X emissions from the glass manufacturing industry. The EPA also reviewed permit data for existing glass manufacturing furnaces to identify control devices currently in use at these sources. Based on these reviews, we find that the final emissions limits for the Glass and Glass Product Manufacturing industry provided in Table VI.C.3–1 generally reflect a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

TABLE VI.C.3–1—SUMMARY OF FINALIZED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lbs/ton of glass produced, 30 operating-day rolling average)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

Alternative Emissions Standards During Periods of Start-Up, Shutdown, and Idling

Comment: Numerous commenters urged the EPA to provide additional flexibilities, alternative NO_X emissions limits, or exceptions to the NO_X emissions limits for glass manufacturing furnaces during periods of startup, shutdown and idling. Commenters requested that the EPA consider excluding days with low glass pull (*e.g.,* abnormally low production rate), furnace start-up days, furnace maintenance days, and malfunction days from the definition of ''operating day'' to allow for exclusion of these days from the calculation of an emissions unit's 30-operating day rolling average emissions. The commenters argued that because the glass furnace temperature is much lower during these periods than they are during normal operating conditions, it would be technologically infeasible to equip furnaces with NO_X control devices including SCR. Commenters also stated that because control equipment cannot be operated during these periods without damaging the equipment, it would be very difficult or impossible to meet the proposed NO_X limits during these periods.

Response: After review of the comments received and the EPA's assessment of current practices within

[389] For example, Pennsylvania's RACT NO_X emission limits for flat glass furnaces are 7.0 lbs of NO_X per ton of glass produced on 30-day rolling average. *See* Title 25, Part I, Subpart C, Article III, Section 129.304, available at *https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements.*

[390] See Proposed Non-EGU Sectors TSD at 56, EPA–HQ–OAR–2021–0668–0145.

the glass manufacturing industry, the EPA is establishing provisions for alternative work practice standards and emissions limits that may apply in lieu of the emissions limits in § 52.44(c) during periods of start-up, shutdown, and idling. The emissions limits for glass melting furnaces in § 52.44(c) do not apply during periods of start-up, shutdown, and/or idling at affected units that comply instead with the alternative requirements for start-up, shutdown, and/or idling periods specified in § 52.44(d), (e), and/or (f), respectively. The EPA has modeled these alternative requirements that apply during startup, shutdown, and idling to some extent on State RACT requirements identified by commenters.[391] These alternative work practice standards adequately address the seven criteria that the EPA has recommended states consider when establishing appropriate alternative emissions limitations for periods of startup and shutdown.[392] We provide a more detailed evaluation of these provisions in the TSD supporting this final rule.

Specifically, each owner or operator of an affected unit seeking to comply with alternative work practice standards in lieu of emissions limits during startup or shutdown periods must submit specific information to the Administrator no later than 30 days prior to the anticipated date of startup or shutdown. The required information is necessary to ensure that the furnace will be properly operated during the startup or shutdown period, as applicable. The final rule establishes limits on the number of days when the owner or operator may comply with alternative work practice standards in lieu of emissions limits during startup and shutdown, depending on the type of glass furnace. Additionally, the owner or operator must maintain operating records and additional documentation as necessary to demonstrate compliance with the alternative requirements during startup or shutdown periods. For startups, the owner or operator must place the emissions control system in operation as soon as technologically feasible to minimize emissions. For shutdowns, the owner or operator must operate the emissions control system whenever technologically feasible to minimize emissions.

For periods of idling, the owner or operator of an affected unit may comply with an alternative emissions limit calculated in accordance with a specific equation to limit emissions to an amount (in pounds per day) that reflects the furnace's permitted production capacity in tons of glass produced per day. Additionally, the owner or operator must maintain operating records as necessary to demonstrate compliance with the alternative emissions limitations during idling periods. During idling, the owner or operator must operate the emissions control system to minimize emissions whenever technologically feasible.

All-Electric Glass Furnaces

The EPA solicited 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 also requested 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.[393] The EPA received numerous comments from the glass industry regarding their concerns with replacing an existing glass manufacturing furnace with an all-electric melter. The commenters stated that various operational restrictions present within all-electric furnaces prevent these units from being implemented throughout the industry, including limited glass production output, reduced glass furnace life, and increased glass plant operating cost due to high levels of electric current usage. Based on the EPA's review of comments submitted on this issue, the EPA has decided not to establish any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time. We provide in the following paragraphs a summary of the comments and the EPA's responses thereto.

Comment: One commenter stated that the lifetime of an all-electric glass melting furnace is only about three to five years before it must be rebricked, compared to well-maintained natural gas or hybrid furnace that may be operated continuously for as long as fifteen to twenty years between rebricking events. The commenter also states that electric furnaces for manufacture of glass containers are limited to a maximum glass production of about 120 tons per day, which is a stark contrast to large natural gas fired glass melting furnaces, which are capable of producing over 400 tons of glass per day. The commenter also stated that the cullet percentage is greatly reduced in all-electric furnaces which increases energy consumption in the affected facility.

Response: At proposal, the EPA solicited comment on whether it is feasible or appropriate for owners or operators of existing glass manufacturing furnaces to phase out and retire their units and replace them with less emitting units like all-electric furnace installations. As explained in the Final Non-EGU Sectors TSD, over the last few decades the demand for flat, container, and pressed/blown glass has continued to grow annually. Nitrogen oxides remain one of the primary air pollutants emitted during the production and manufacturing of glass products. However, no current Federal CAA regulation controls NO_X emissions from the industry on a category-wide basis.[394] Therefore, the glass manufacturing industry has conducted various pollution prevention and research efforts to help identify preferred techniques for the control of NO_X. Some of these studies revealed recent trends to control NO_X emissions in the glass industry, including the use of all-electric glass furnaces. We understand based on the comments received from the glass manufacturing industry that significant differences exist in the design, configuration, age, and replacement cost of glass furnaces and in the feasibility of controls and raw material compositions. These differences as well as the production limitations present with all-electric furnaces create difficulties in implementing all-electric furnaces across the industry while keeping up with glass product demands. Therefore, the EPA is not mandating any requirement for owners or operators of existing glass manufacturing furnaces to replace their units with all-electric furnaces.

Combustion Modification and Post-Combustion Modification Control Devices

According to the EPA's "Alternative Control Techniques Document—NO_X Emissions from Glass

[391] See Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305–129.307 (effective June 19, 2010), available at *https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/chap129toc.html&d=reduce* and San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces," sections 5.5–5.7 (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf*.

[392] See 80 FR 33840, 33914 (June 12, 2015) (identifying the EPA's recommended criteria for developing and evaluating alternative emissions limitations applicable during startup and shutdown).

[393] *See* definitions in 40 CFR part 60, subpart CC.

[394] See Final Non-EGU Sectors TSD.

Manufacturing,'' [395] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. At proposal, the EPA solicited comments 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 or operate a post-combustion modifications control device like SNCR or SCR to further improve their NO_X removal efficiency. The EPA received numerous comments from the glass industry that detailed the differences present in glass furnace designs, operations and finished product that influenced the type of combustion modification or post-combustion modification control device that is feasible for such unit. Several commenters have requested that the EPA focus on establishing an emissions limit rather than specifying the use of a particular control technology given the significant differences across glass furnaces. As a result of the comments received, the EPA is not specifically requiring affected units to install combustion modification and post-combustion controls to meet the finalized emissions limits. The EPA is finalizing the emissions limits as proposed, which may be met with combustion modifications (*e.g.,* low-NO_X burners, oxy-firing), process modifications (*e.g.,* modified furnace, cullet preheat), and/or post-combustion controls (SNCR or SCR) and thus provide sources some flexibility to choose the control technology that works best for their unique circumstances.

Comment: Multiple commenters responded to EPA's request for comments by stating it is unnecessary and unhelpful for the proposed rule to specify use of particular post-combustion control device. The commenters note that various flat glass furnaces have a variety of combustion and post-combustion control options. Each furnace is different in its design, operations, and finished product produced. The commenters state that it is more appropriate for EPA to establish an emissions limit in the proposed rule than it is for the EPA to specify use of a particular control technology.

Response: In response to these comments, the EPA is not establishing any requirements for affected units to install specific control technologies to meet the emissions limits. The EPA is finalizing the limits as proposed to offer sources some flexibility to choose the control technology that works best for their unique circumstances.

Compliance Assurance Requirements

The EPA proposed to require owners or operators of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces to install, calibrate, maintain and operate a CEMS for the measurement of NO_X emissions discharged. The EPA also solicited comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. The EPA received numerous comments from the glass industry expressing concern with any requirement to use CEMS at affected units. After review of the comments received and EPA's assessment of practices conducted within the glass manufacturing industry, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnaces to demonstrate compliance through annual testing or use CEMS, or similar alternative monitoring system data in lieu of a performance test. The EPA is also establishing recordkeeping provisions that require owners or operators of affected units to conduct parametric monitoring of fuel use and glass production during performance testing to assure continuous compliance on a 30-operating day rolling average.

Comment: Commenters representing the glass industry stated that a requirement to install and operate CEMS would present significant costs and technical complexities in a situation where emissions can be effectively monitored using stack testing rather than continuous monitoring. Commenters also objected to the EPA's proposal to require CEMS together with semi-annual stack testing. Commenters stated that a requirement to both operate CEMS and conduct semi-annual testing would be unnecessary and excessive and would not provide commensurate benefit unless a facility's emissions are near or above the proposed emissions limit. Commenters requested that owners or operators of affected units be allowed to use alternative monitoring systems, *e.g.,* parametric emissions monitoring. The commenters stated that parametric monitoring requires less initial and ongoing manpower requirements, has lower capital and operating costs than CEMS, does not require spare parts, and is accurate over a mapped range.

Response: The EPA is establishing compliance assurance requirements that provide flexibility to owners or operators of affected units. Compliance with the emissions limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season.

5. Boilers at Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Iron and Steel and Ferroalloys Manufacturing, and Metal Ore Mining facilities

Applicability

The EPA is finalizing regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing industry, Basic Chemical Manufacturing industry, Petroleum and Coal Products Manufacturing industry, Pulp, Paper, and Paperboard Mills industry, and the Metal Ore Mining industry that apply to boilers that have a design capacity of 100 mmBtu/hr or greater. The Non-EGU Screening Assessment memorandum developed in support of Step 3 of our proposal identified emissions from large boilers in certain industries (*i.e.,* those projected to emit more than 100 tpy of NO_X in 2026) as having adverse impacts on downwind receptors. As discussed in the proposed rule, we developed applicability criteria for boilers based on design capacity (*i.e.,* heat input), rather than on potential emissions, because use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. In this final rule, we are establishing the heat input-based applicability criteria described in our proposal, with some adjustments as explained further in this section. Additionally, we have determined that boilers meeting these applicability

[395] EPA, Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing, EPA–453/R–94–037, June 1994.

criteria exist within the following five industries: Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and Iron and Steel Mills and Ferroalloy Manufacturing.

As we explained in the proposed rule, the potential emissions from industrial boilers with a design capacity of 100 mmBtu/hr or greater burning coal, residual or distillate oil, or natural gas can equal or exceed the 100 tpy threshold that we used to identify impactful boilers within the Non-EGU Screening Assessment memorandum. We are finalizing NO_X emissions limits that apply to boilers with design capacities of 100 mmBTU/hr or greater located at any of the five identified industries in any of the 20 covered states with non-EGU emissions reduction obligations. In response to comments on our proposed rule, however, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year and provisions for EPA approval of alternative emissions limits on a case-by-case basis, where specific criteria are met. Additionally, only boilers that combust, on a BTU basis, 90 percent or more of coal, residual or distillate oil, natural gas, or combinations of these fuels are subject to the requirements of these final FIPs.

The EPA has determined that boilers meeting the applicability criteria of this section exist within the five industrial sectors identified in Table VI.C.5–1:

TABLE VI.C.5—1: NON-EGU 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
Iron and Steel and Ferroalloys Manufacturing	3311xx
Metal Ore Mining	2122xx

Comment: Several commenters requested that the EPA establish PTE-based applicability criteria for boilers as it had proposed to do for other non-EGU sectors and stated that using heat input as the basis for determining applicability would result in low-emitting boilers being subject to the final rule's control requirements. Commenters stated that the EPA should provide a low-use exemption for infrequently run units because these units produce a lower amount of emissions.

Response: The EPA is finalizing applicability criteria for boilers based on boiler design capacity for a number of reasons. First, Federal emissions standards applicable to boilers[396] and all of the state RACT rules that we reviewed contain applicability criteria based on boiler design capacity. Second, as explained in the Final Non-EGU Sectors TSD, most boilers with design capacities of 100 mmBTU/hr or greater that are fueled by coal, oil, or gas have the potential to emit 100 tpy or more of NO_X. Thus, use of a boiler design capacity of 100 mmBtu/hr for applicability purposes reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. Finally, use of a boiler's design capacity for applicability purposes facilitates applicability determinations given that a boiler's design capacity is, in most cases, clearly indicated by the manufacture on the unit's nameplate.

In response to the comments expressing concern that infrequently-operated boilers would be captured by the EPA's proposed applicability criteria, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. Such boilers will be exempt from the emissions limits in these FIPs provided they operate less than 10 percent per year, on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years, but will have recordkeeping obligations. The EPA finds it appropriate to exempt such low-use boilers from the emissions limits in this final rule because the amount of air pollution emitted from a boiler is directly related to its operational hours, and installation of controls on infrequently operated units results in reduced air quality benefits.

Comment: Commenters asked whether the EPA's proposed emissions limits for boilers would apply to emissions units that burn fuels other than coal, residual or distillate oil, or natural gas. For example, one commenter stated that some biomass boilers start up by co-firing oil or gas and that some NO_X controls such as low-NO_X burners (LNB) cannot be used on biomass boilers. The commenter requested clarification on whether boilers burning biomass would be covered by the EPA's proposed requirements. Other commenters noted that some industrial boilers burn natural gas in conjunction with other gaseous fuels, such as hydrogen/methane off-gas and vent gas from various on-site processes, and may not be able to meet the EPA's proposed 0.08 lb/mmBtu NO_X emissions limit for boilers burning natural gas. One commenter stated that it operated a boiler that burns hazardous waste and is subject to 40 CFR part 63, subpart EEE, National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors, and that this boiler uses natural gas for start-up and at other times to stabilize operations but also combusts other fuels such as liquid waste. The commenter asserted that such boilers should not be covered by the final rule.

Response: In recognition and consideration of comments received on our proposal, the EPA is finalizing requirements for boilers that apply only to boilers burning 90 percent or more coal, residual or distillate oil, or natural gas or combinations of these fuels on a heat-input basis. Public commenters presented information indicating that the burning of fuels other than coal, residual or distillate oil, or natural gas at levels exceeding 10 percent may interfere with the functions of the control technologies that may be necessary to the meet the final rule, like SCR. The EPA does not have sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost. Therefore, boilers that burn greater than 10 percent fuels other than coal, residual or distillate oil,

[396] *See, e.g.,* 40 CFR 60.44b (subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements of this final rule.

Comment: Some commenters claimed that the EPA cannot include emissions limits for boilers that burn combinations of coal, residual or distillate oil, and natural gas, because the EPA did not propose limits for such boilers. Other commenters suggested it would be appropriate to establish emissions limits for such boilers as long as the EPA provides criteria for establishing such emissions limits.

Response: The EPA disagrees with the claim that boilers burning combinations of coal, residual or distillate oil, or natural gas cannot be covered by the final FIP because the EPA did not propose specific emissions limits for these boilers and agrees with commenters who stated that the EPA's proposed emissions limits can be extended to such boilers provided the EPA provides criteria for doing so. The applicability criteria in the final rule cover boilers burning combinations of coal, residual or distillate oil, or natural gas and include a methodology for determining the emissions limits for such units based on a simple formula that correlates the amount of heat input expended while burning each fuel with the corresponding emissions limit for that particular fuel. For example, a boiler with a heat input of 85 percent natural gas and 15 percent distillate oil would be subject to an emissions limit derived by multiplying the natural gas emissions limit by 0.85 and adding to that the distillate oil emissions limit multiplied by 0.15. Thus calculated, the NO_X emissions limits for boilers burning combinations of coal, residual or distillate oil, or natural gas are consistent with the NO_X emissions limits identified in our proposed rule for each of these individual fuels.

Emissions Limitations and Rationale

The EPA is finalizing all of the proposed NO_X emissions limits for industrial boilers and adding a formula for calculating emissions limits for multi-fueled units as shown in Table VI.C.5–2. The emissions limits apply to boilers with design capacities of 100 mmBtu/hr or greater located at any of the five industries identified in Table II.A–1 within any of the 20 states covered by the non-EGU requirements of this final rule.

TABLE VI.C.5–2—NO_X EMISSIONS LIMITS FOR BOILERS >100 mmBtu/hr

[Based on a 30-day rolling average]

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20.
Residual oil	0.20.
Distillate oil	0.12.
Natural gas	0.08.
Multi-fueled unit	Limit derived by formula based on heat input contribution from each fuel.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided in the Final Non-EGU Sectors TSD.

Comment: Some commenters noted that many boilers are already subject to other state and Federal controls, and that programs such as RACT, NSR, BACT, NSPS, and maximum achievable control technology (MACT) are all achieving emissions reductions from boilers.

Response: The EPA acknowledges that some affected units may already be meeting the emissions limits established in this rule as a result of controls installed to comply with other regulatory programs, such as the CAA's RACT requirements. However, emissions from the universe of boilers subject to the applicability requirements of this final rule are not being uniformly reduced by these programs to the same extent that the limits we are adopting will require, nor for the same reason, which is to mitigate the impact of emissions from upwind sources on downwind locations that are experiencing air quality problems. The EPA has determined that the limits we are finalizing in this action are readily achievable and are already required in practice in many parts of the country.

Regarding RACT controls, some of the sources covered by the final rule are not subject to RACT requirements because RACT is only applicable to sources located in ozone nonattainment areas and in the OTR, and many sources covered by the final rule are not located within such jurisdictions. Regarding sources that are subject to RACT, we note that unlike RACT requirements applicable to sources of VOCs, where a majority of such sources are covered by state RACT rules adopted to conform with uniform ''presumptive'' limits contained within the EPA's Control Technique Guidelines (CTGs), in most cases presumptive NO_X emissions limits have not been established for industrial sources of this pollutant. In light of this, NO_X RACT requirements are primarily determined on a state-by-state basis and exhibit a range of stringencies as determined by each state. Additionally, RACT requirements tend to become more stringent with the passage of time as existing control options are improved, and new options become available. Thus, older RACT determinations may not be as stringent as more recent determinations made for similar equipment types. As noted in our proposal, we based our NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired industrial boilers on RACT limits that are already in place in many areas of the country.

Regarding NSR control requirements, we note that the NSR program was created by the 1977 amendments to the CAA and applies only to new or modified stationary sources. Many of the boilers covered by the applicability requirement of this final rule were initially installed or last modified prior to 1977 and have not undergone NSR analysis, such as a BACT analysis for sources located within an attainment area or a LAER analysis for sources located within nonattainment areas. Additionally, BACT and LAER determinations made many years ago are not likely to be as stringent as more recent determinations.

Regarding NSPS requirements, 40 CFR part 60, subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, contains NO_X emissions limits for boilers with capacities of 100 mmBTU/hr or greater that were constructed or modified after June 19, 1984, and so boilers constructed or modified prior to that date are not subject to its requirements. Additionally, the limits for coal, residual or distillate oil, and gas-fired units are not as stringent as more recent limits adopted by states pursuant to RACT control obligations.

Lastly, MACT controls are primarily designed to reduce emissions of hazardous air pollutants, not to reduce NO_X emissions. We anticipate the MACT program's boiler tune-up requirement should reduce NO_X emissions to some extent, but not to the extent that compliance with the limits adopted within this final rule will achieve.

Comment: One commenter noted that a 2017 OTC survey found that boilers, including those used in the paper products, chemical, and petroleum industries, are already required to achieve more stringent limits, and pointed to limits for distillate oil that are lower than what the EPA considered in developing the proposal. The commenter also noted that California's South Coast Air Quality Management District has adopted a facility-wide NO_X emissions limit of 0.03 lb/mmBtu at petroleum refineries. The commenter noted that CEMs data shows a residual oil-fired boiler at the Ravenswood Steam Plant in New York achieves an average NO_X emissions rate of 0.0716 lb NO_X/MMBtu and that CEMS data shows that a gas-fired boiler in Johnsonville, Tennessee, achieves an average NO_X emissions rate of 0.0058 lb NO_X/mmBTU. Regarding coal-fired boilers, the commenter stated that a coal boiler at the Ingredion Incorporated Argo Plant in Illinois achieves an average NO_X emissions rate of 0.1153 lb NO_X/MMBtu with selective non-catalytic control technology, and the Axiall Corporation facility in West Virginia achieves a 0.1162 lb/mmBtu using low-NO_X burner technology with overfire air. The commenter also noted that more than half of the gas-fired boilers included in the air markets program database already emit NO_X at rates below the EPA's proposed emissions rate, and that the RACT/BACT/LAER Clearinghouse (RBLC) shows more stringent limits for gas boilers than the limits the EPA proposed, with many facilities being required to meet a NO_X limit of less than 0.0400 lb/mmBtu.

Response: The EPA's intent was not to set the NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired boilers to match the lowest levels required elsewhere by state or local authorities, but rather to establish limits that are commensurate with broadly applicable RACT limits currently in place in a number of states as noted within our proposal. The limits we selected were not the most stringent of the state RACT rules we reviewed but were relatively close to that value. We did not select the most stringent limits because such limits may reflect case-specific technological and economic feasibility considerations that do not apply more broadly across the industry. Furthermore, although the EPA acknowledges that some industrial boilers powered by coal, residual or distillate oil, natural gas, or combinations of these fuels can meet very low NO_X emissions limits as noted by the commenter, it is unlikely that all such units could meet these limits given case-specific considerations such as boiler design and operation, some of which limit the types of control technology that may be available to a particular unit.

a. Coal-Fired Industrial Boilers

As we proposed, coal-fired industrial boilers subject to the applicability requirements of this section are required to meet a NO_X emissions limit of 0.2 lb/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 retrofit with equipment to meet this emissions limit. As we explained in our proposal, many states containing ozone nonattainment areas or located within the OTR have already adopted RACT emissions limits similar to or more stringent than the limits in this final rule, and most of those RACT limits apply statewide and extend to boilers located at commercial and institutional facilities, not just to boilers located in the industrial sector.

Comment: One commenter noted that the coal-fired boilers it operates already use combustion controls to reduce NO_X emissions and contended that the effectiveness of SNCR on these boilers is unknown but would likely be on the low end of the control effectiveness range because they experience variable loads, which would compromise the proper functioning of an SNCR control system. The commenter stated that the only way their coal-fired boilers would be able to comply with the EPA's proposed NO_X limit would be to install SCR. The commenter added that for coal-fired industrial boilers with a heat input rating of 100 MMBtu/hr or more, a review of the available RBLC records indicates that out of the 23 RBLC entries identified, nine units (less than half) were subject to an emissions limit at or below 0.2 lb/mmBtu, and eight of these nine units were equipped with SNCR. The commenter stated that based on a review of the available data in the RBLC and given the technical difficulties and low control efficiencies when applying SNCR to swing boilers, the EPA's proposed limit for coal firing does not appear achievable for industrial coal-fired boilers that experience load swings unless SCR is installed. Other commenters stated that while there have been recent advancements in SNCR technology, such as the setting up of multiple injection grids and the addition of sophisticated CEMs-based feedback loops, implementing SNCR on industrial load-following boilers continues to pose several technical challenges, including lack of achievement of optimal temperature range for the reduction reactions to successfully complete, and inadequate reagent dispersion in the injection region due to boiler design which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.,* large ammonia slip). The commenter noted that at least one pulp mill boiler had to abandon its SNCR system due to problems caused by poor dispersion of the reagent within the boiler, and that SNCR has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads.

Response: To the extent the commenter's concerns pertain primarily to SNCR control technology, we note that the final rule does not mandate the use of any particular type of control technology and that other types of control equipment such as SCR should be examined as a means for meeting the final emissions limits. The EPA acknowledges that some coal-fired industrial boilers subject to this section of the final rule may need to install SCR to meet the NO_X emissions limits. This is reflected in our evaluation of costs for the non-EGU sector contained within the Non-EGU Screening Assessment memorandum and the cost calculations for the final rule discussed in section V and the *Memo to Docket—Non-EGU Applicability Requirements and Estimate Emissions Reductions and Costs.* We note that although the RBLC contains information on emissions limits and control technology for some units, it only provides information on a relatively small number of units subject to NO_X emissions limits and operating NO_X controls. Additionally, our final rule provides an exemption for units that operate infrequently (*i.e.,* ''low-use boilers''), and also allows a facility owner or operator to submit a request for a case-by-case alternative emissions limit in cases where compliance with the emissions limit in this final rule is technically impossible or would result in extreme economic hardship. We note that non-EGU boilers share many similarities with EGU boilers, many of which already operate SCR to control NO_X emissions or will be required to install and operate SCR systems under the requirements for EGUs contained in this final rule. Lastly, we note that information collected during the development of updates to the EPA's MACT requirements for industrial, commercial, and institutional (ICI) boilers indicates that over 150 ICI boilers have installed SCR control systems to reduce their NO_X emissions. This information is available in the docket for this final rule.

All affected units must install and operate NO_X control equipment as necessary to meet the applicable emissions limits in the final rule, except that if the owner or operator requests, and the EPA approves, a case-by-case emissions limit based on a showing of technical impossibility or extreme economic hardship, the affected unit would be required to comply with the EPA-approved case-by-case emissions limit instead.

b. Residual or Distillate Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. We proposed a NO_X emissions limit of 0.2 lb/mmBtu [397] for residual oil-fired boilers and proposed a NO_X emissions limit of 0.12 lb/mmBtu for distillate oil-fired boilers. We are finalizing both limits as proposed, based on 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 generally enable facilities meeting the applicability criteria of this section to meet these emissions limits, and the Final Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits in this final rule. There are relatively few boilers fueled by residual or distillate oil within the industries affected by this final rule that meet the applicability criteria of this section, and we received relatively few comments regarding our proposed emissions limits for them.

c. Natural Gas-Fired Industrial Boilers

We proposed a NO_X emissions limit of 0.08 lb/mmBtu based on a 30-day rolling average for natural gas-fired boilers meeting the applicability criteria of this section, and we are finalizing this emissions limit and averaging time as proposed. As explained in our proposal, numerous combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet this emissions limit. Additionally, many states have already adopted emissions limits similar to the emissions limit in this final rule, and some natural gas-fired industrial boilers may be able to meet the 0.08 lb/mmBtu emissions limit by modifying existing NO_X control equipment installed to meet the requirements in 40 CFR 60.44b (subpart Db of 40 CFR part 60, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), which already requires that natural gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu.

Compliance Assurance Requirements

We proposed compliance provisions for boilers subject to the requirements of this section similar to the emissions monitoring requirements found in 40 CFR 60.45 (subpart D of 40 CFR part 60, Standards of Performance for Fossil-Fuel-Fired Steam Generators). Those requirements include, among other provisions, the performance of an initial compliance test and installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the emissions limit in this final rule. We received a number of comments on this portion of our proposal and provide responses to some of these comments in the following paragraphs. Our full responses to comments are provided in the response to comments document included in the docket for this action.

Comment: A number of commenters stated that CEMS monitoring is too expensive and unnecessary for ensuring compliance with the emissions limits for boilers and requested that alternative monitoring techniques be allowed.

Response: The EPA acknowledges that the installation and operation of CEMs systems is more expensive than other monitoring techniques and may not be necessary for smaller sized boilers that typically produce less emissions than larger ones. In response to these comments, we have modified the monitoring requirements in the final rule such that boilers rated with heat-input capacities less than 250 mmBTU/hr can demonstrate compliance by conducting an annual stack test as an alternative to monitoring using a CEMs system and by complying with the provisions of a monitoring plan meeting specific criteria that enables the facility owner or operator to demonstrate continuous compliance with the emissions limits of this final rule.

Comment: One commenter stated that the proposed reporting obligations require the submittal of excess emissions reports, continuous monitoring, and quarterly emissions reports. The commenter suggested that since the NO_X emissions standards only apply during the ozone season (May 1–September 30), the reporting requirements should only apply during the second and third quarters of the year and should require that only emissions and monitoring data from this time period be included in these reports.

Response: In response to these comments, the EPA is finalizing recordkeeping, monitoring, and reporting requirements that are designed to ensure compliance with the applicable emissions limits only during the ozone season. Additionally, the final rule requires annual reports rather than the proposed quarterly reports as annual reports are adequate to determine compliance with the emissions limits during the ozone season.

Comment: A number of commenters stated that some of their boilers that may potentially be subject to a final FIP already have a NO_X CEMS installed and requested that the EPA clarify whether a 30-day initial compliance test is required in such cases.

Response: The EPA's final rule provides that in instances where a boiler meeting the applicability requirements of this section has already installed a NO_X CEMs that meets the requirements for such equipment located within 40 CFR 60.13 or 40 CFR part 75, Continuous Emissions Monitoring, pursuant to a federally enforceable requirement, a 30-day initial compliance test is not required.

Comment: One commenter stated that § 52.45(d) of the EPA's proposed rule included requirements to complete an initial 30-day compliance test within 90 days of installing pollution control equipment but did not specify whether the test must be complete prior to the May 1, 2026, ozone season or by some later date.

Response: In response to this comment, the EPA is finalizing provisions requiring that initial compliance tests occur prior to the May 1, 2026 compliance date.

6. Municipal Waste Combustors

Applicability

The EPA is finalizing regulatory requirements that apply to municipal solid waste combustors located in a state subject to the non-EGU requirements of this final rule (*i.e.,* the 20 states with linkages that persist in 2026 as identified in section II.B) and

[397] Section 52.45(c) of the regulatory text in our proposed rule identified a proposed emissions limit of 0.15 lb/mmBtu for residual oil-fired boilers, but the emissions limit that we intended to propose for this equipment and discussed both in the preamble to the proposed rule and in the TSD supporting the proposed rule was 0.20 lb/mmBtu.

that combust greater than or equal to 250 tons per day of municipal solid waste (''affected units''). *See* 40 CFR 52.46(d) for guidelines on calculating municipal waste combustor unit capacity. This applicability threshold was supported by commenters and is consistent with the applicability criteria in 40 CFR part 60, subpart Eb, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Large Municipal Waste Combustors. State RACT rules for MWCs and the OTC MWC report similarly define large MWC units as units with a combustion capacity greater than or equal to 250 tons per day.

Across the 20 states subject to the non-EGU requirements, this applicability threshold captures 28 MWC facilities with a total of 80 affected units. The identified affected units include mass burn waterwall units, mass burn rotary waterwall units, refuse derived fuel (RDF) units, and one CLEERGAS™ (''Covanta Low Emissions Energy Recovery Gasification'') modular system.[398] The EPA analyzed actual emissions from the facilities captured by this threshold and found that on average, a unit with a design capacity of 250 tons per day has a PTE of approximately 138 tons per year,[399] which is similar to the PTE threshold applied to other non-EGU sources under this rulemaking.

Emissions Limitations and Rationale

Based on the available information for this industry, including information provided during the public comment period, the OTC MWC Report, a review of State and local RACT rules that apply to MWCs, and active air permits issued to MWCs, the EPA is finalizing the following emissions limits for municipal solid waste combustors.

TABLE VI.C.6–1—NO_X EMISSIONS LIMITS FOR LARGE MUNICIPAL WASTE COMBUSTORS

NO_X Limit (ppmvd) corrected to 7 percent oxygen	Averaging period
110	24-hour.
105	30-day.

At proposal, the EPA noted that the NO_X limits for large MWCs constructed on or before September 20, 1994 under NSPS 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 large MWCs constructed after September 20, 1994 or for which modification or reconstruction is commenced after June 19, 1996 under NSPS subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lb/mmBtu, respectively. In reviewing active air permits for MWCs, the EPA found that most MWCs are meeting emissions limits similar to those reflected in the applicable NSPS.[400]

The EPA also cited the OTC's MWC report that evaluated the emissions reduction potential of large MWCs located in the OTR from two different control levels, one based on a NO_X concentration of 105 to 110 ppm, and another based on a limit of 130 ppm. The OTC MWC report found that a control level of 105 ppmvd on a 30-day rolling average basis and a 110 ppmvd on a 24-hour block 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 OTR MWC Report noted that at the time of publication, eight MWC units were already subject to permit limits of 110 ppm, seven in Virginia, and one in Florida. In consideration of control costs, the report cited multiple studies evaluating MWCs similar in design to the large MWCs in the OTR and found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced.

To further inform the EPA's consideration of emissions limits for MWCs, the EPA requested comment on the emissions limit and averaging time MWCs should be required to meet, and specifically whether the EPA should adopt emissions rates of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Comment: The agency received several comments regarding emissions limits and averaging time for MWCs. Many commenters asserted that the EPA should set a 24-hour emissions limit no higher than 110 ppm, noting that recent studies have shown that there are a variety of technologies that can help a wide range of MWC types achieve this limit at costs that are significantly below the $7,500/ton cost effectiveness threshold that the EPA identified at proposal. Some commenters confirmed the accuracy of the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 while others stated that the cost of controls is well below $7,500. One commenter asserted that the EPA should set a 24-hour NO_X emissions limit of 50 ppmvd for MWCs, which could be achieved by the installation of SCR technology. Alternatively, the commenters stated that the EPA should set a 24-hour emissions limit no higher than 110 ppm based on less effective, though still widely available, control technology. Although some commenters stated that MWCs should not be included in the rulemaking, no commenters specifically identified units or categories of units that could not achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Response: The EPA recognizes that there have been instances where MWCs have installed SCR and achieved emissions rates of 50 ppmvd on a 24-hr averaging basis and 45 ppmvd on a 30-day rolling averaging basis with cost effectiveness estimates around $10,296/ton to $12,779/ton of NO_X reduced. Given uncertainties pertaining to whether SCR can be installed on all types of MWCs, the EPA has decided not to establish emissions limits as low as 50 ppmvd for MWCs using SCR at this time. However, as generally supported by most commenters, the EPA is finalizing emissions limits of 105 ppmvd at 7 percent oxygen (O_2) on a 30-day rolling average and 110 ppmvd at 7 percent O_2 on a 24-hour block average that apply at all times except during periods of startup and shutdown. The EPA recognizes that the final emissions limits for steady-state operations cannot be achieved during periods of startup, shutdown, and malfunction. This is primarily due to the fact that during periods of startup and shutdown, additional ambient air is introduced into the units, resulting in higher oxygen concentrations. Therefore, the EPA is finalizing provisions applicable during periods of startup and shutdown that do not require correction of CEMS data to 7 percent oxygen but do require that such data be measured at stack oxygen content. This approach is consistent with EPA regulations applicable during startup and shutdown periods for other solid-waste incinerators under the NSPS for Commercial and Industrial Solid Waste Incineration Units. *See* 40 CFR part 60, subparts CCCC and DDDD.

[398] *See* the Final Non-EGU Sectors TSD for additional information on this inventory.

[399] *See* the Final Non-EGU Sectors TSD for additional information on the calculation of PTE for large MWCs.

[400] For further discussion of the permits reviewed, see the Final Non-EGU Sectors TSD.

Information received from public commenters generally aligned with the results from studies showing that the emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis can be reached using ASNCR or low NO_X technology in addition to SNCR.[401] The EPA recognizes that not all units can implement low NO_X technology, including those using Aireal grate technology, those operating RFD units, and those with rotary combustor units. Of the 80 affected MWC units that the EPA identified, nine units across two facilities are classified as rotary combustors, four units at a single facility are classified as RDF, and no units captured are classified as using Aireal grate technology. One affected unit is classified as CLEERGAS gasification while the remaining 64 affected units are classified as mass burn waterwall combustors, which have not been explicitly identified as units unable to install low NO_X technology. For those units unable to install low NO_X technology or SNCR, the EPA has identified ASCNR as an alternative control technology that has been shown to enable units to achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis, either as a new retrofit technology or as a significant upgrade to existing SNCR. The EPA finds that the availability of ASNCR or SNCR and low NO_X burners provides sufficient flexibility for MWCs to meet the emissions limits in the final rule, especially considering 74 of the 80 affected units already have SNCR installed. Although there is uncertainty on the cost effectiveness of ASNCR for achieving significant NO_X reductions in small MWCs, small MWCs that combust less than 250 tons per day of municipal solid waste are not included in this rulemaking.

While commenters noted discrepancies across cost effectiveness values for specific types of control technology, no commenters specifically indicated that emissions control technology could not be cost effectively installed on large MWCs to achieve an emissions limit of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis. Studies show that these limits can be achieved through a variety of emissions controls, including ASNCR and the addition of low NO_X technology to existing SNCR.[402] Of the 80 MWC units subject to this rule, 55 units already have SNCR installed, 16 units already have SNCR and low NO_X technology installed, and three units already have ASNCR installed. Applying the cost values provided in the OTC's MWC report to the MWC inventory in section 7 of the Final Non-EGU Sectors TSD, the estimated weighted average cost effectiveness of applying advanced SNCR to units with and without existing SNCR and adding low NO_X technology to eligible units with SNCR was found to be approximately $7,929.02/ton.[403] This value is in line with the control technology costs for other non-EGU sectors and the EGU costs associated with this final rule.

Compliance Assurance Requirements

In this final rule, the EPA is establishing compliance requirements for MWCs similar to the NSPS requirements for large MWCs under 40 CFR part 60, subpart Eb. Those requirements include, among other provisions, the performance of an initial performance test and installation of a CEMS. At proposal, the EPA requested comment on whether it would be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under applicable NSPS or other requirements.

Comment: Some commenters noted that all large MWCs are already required to use CEMS to demonstrate compliance with NO_X limits under the NSPS program. These commenters asserted that the EPA should improve electronic reporting requirements beyond current requirements in the NSPS. The commenters suggested that an owner or operator of an MWC subject to a limit under the final rule should be required to report NO_X CEMS data electronically at least annually to the EPA's CEDRI and any other database that the EPA will utilize when considering revisions to the NSPS for large MWCs. The commenters asserted that MWC operators should be required to report NO_X CEMS data to the EPA's Clean Air Markets database, to allow the public access to MWC CEMS data on a large scale for the first time.

Response: The EPA is finalizing provisions that require MWCs subject to the requirements of 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. This is consistent with NSPS requirements for large MWCs under 40 CFR part 60, subparts Ea and Eb, and state RACT rules that are applicable to MWCs in many of the states covered under this rulemaking.[404] Additionally, each emissions unit will be required to conduct an initial performance test. With regard to electronic reporting, the final rule requires performance tests and reports, including CEMS data, to be submitted to CEDRI, as required for all non-EGU industries covered by this final rule.

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. As discussed in this section, states may opt for one of several alternatives that the EPA has provided to take over all or portions of the FIP. However, as discussed in greater detail further in this section, the EPA also recognizes that states retain the discretion to develop SIPs to replace a FIP under approaches that differ from those the EPA has finalized.

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,

[401] The only demonstrated use of low NO_X technology in addition to SNCR at MWC facilities is at Covanta facilities using Covanta's proprietary low NO_X combustion system (LN™). For the purpose of this rule, EPA is assuming Covanta facilities will take advantage of this technology and others will use ASNCR. However, other iterations of low NO_X technology could become available, or facilities could work with Covanta to apply this technology to their units.

[402] *See* OTC MWC Report at 6–7; Trinity Consultants, *Project Report Covanta Alexandria/Arlington, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Trinity Consultants, *Project Report Covanta Fairfax, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Babcock Power Environmental, *Waste to Energy NO_X* Feasibility Study, Prepared for: Wheelabrator Technologies Baltimore Waste to Energy Facility Baltimore, MD (February 20, 2020); White, M., Goff, S., Deduck, S., Gohlke, O., *New Process for Achieving Very Low NO_X, Proceedings of the 17th Annual North American Waste-to-Energy Conference, NAWTEC17* (May 2009); Letter from the State of New Jersey to Michael Klein, In Rreference to Covanta Energy Group, Inc. Essex County Resource Recovery Facility, Newark Annual Stack Test Program (March 14, 2019).

[403] See Final Non-EGU Sectors TSD for more information on these cost effectiveness estimates were generated.

[404] For examples of RACT provisions applicable to MWCs that require CEMS, see Regulations of Connecticut State Agencies section 22a–174–22e; and Virginia Administrative Code section 5–40–6730, subsection (D).

as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this 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 reasonably severable portions of a tribal implementation plan.

Under the FIPs for the 22 states whose EGUs are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with the modifications finalized in this rule, EPA continues to offer ''abbreviated'' and ''full'' SIP options for states. An ''abbreviated SIP'' allows a state to submit a SIP revision that establishes state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaving the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that 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, states have the option 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).

Comments: Some commenters alleged that by taking this action, EPA is depriving states of the ability to develop SIPs to implement good neighbor obligations for the 2015 ozone NAAQS or from choosing their own compliance strategies. Commenters also claimed that the EPA cannot require states to implement emissions reductions equivalent to the emissions control stringency that the EPA determined at Step 3 if their proposed SIPs are otherwise shown to be adequate to eliminate significant contribution. Other commenters raised concerns that the trading program enhancements for EGUs made it too uncertain what a state could develop as an approvable replacement SIP. At least one commenter argued that the EPA must give states a single, mass-based emissions budget so that they can understand how to replace the FIP with a SIP.

Response: The EPA disagrees that it is depriving States of the opportunity to replace the FIP with a SIP or preventing states from targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP. States have always possessed the authority and the opportunity to revise their SIPs at any point. The EPA has repeatedly emphasized that states are free to develop a SIP revision to replace a transport FIP and submit that to the EPA for approval, and this remains true. *See* 87 FR 20036, 20051 (April 6, 2022); 86 FR 23054, 23062 (April 30, 2021); 81 FR 74504, 74506 (Oct. 26, 2016). In the FIP proposal, as in prior transport actions, the EPA discussed a number of ways in which states could take over or replace a FIP, *see* 87 FR 20036, 20149–51 (section VII.D: ''Submitting A SIP''); *see also id.* at 20040 (noting as one purpose in proposing the FIP that ''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''). The EPA provides further guidance on submitting SIPs in this section. If, and when, the EPA receives a SIP submission that satisfies the requirements of CAA section 110(a)(2)(D)(i)(I) and 110(l), the Agency will take action to approve those SIP submissions and withdraw the FIP.

At the outset, we note that the Agency does not anticipate revisiting its findings at Steps 1 or 2 of the transport framework. Those findings establish that the projected baseline anthropogenic emissions from these states contribute to downwind nonattainment or maintenance receptors in 2023, and, for certain states, that contribution continues through 2026. Those represent critical analytical years for downwind areas as they are the last full ozone season before the Moderate and Serious area attainment dates. Those findings, for those years, establish the basis for an upwind state's linkage, from which we proceed to evaluate emissions control opportunities and their implementation at Steps 3 and 4.

We cannot prejudge now whether state submissions to replace the EPA's FIP will be approvable, but we note a number of statutory and implementation considerations states should be aware of if designing a replacement SIP. We have demonstrated that the EPA's transport FIP is adequate to eliminate significant contribution to downwind air quality problems for purposes of the 2015 ozone NAAQS, and that the FIP does not result in overcontrol. The level of reductions required by the FIP therefore provides an important benchmark for states in evaluating the equivalency of possible replacement SIPs. As discussed in more detail in this section, in order to comply with their obligation under CAA section 110(a)(2)(D)(i)(I), we generally anticipate that states seeking to replace the FIP with a SIP that takes an alternative approach would need to establish, at a minimum, an equivalent level of emissions reduction to what the FIP requires at Step 3, and any such replacement SIP will need to comply with CAA section 110(*l*).

The concept of equivalency is important for the state to consider. Under CAA section 110(l), ''the Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment . . . or any other applicable requirement of this chapter.'' Section 110(l) applies to all CAA requirements, including 110(a)(2)(D) requirements relating to interstate transport. The EPA interprets section 110(l) such that states have two main options to make a noninterference demonstration. First, the state could demonstrate that emissions reductions removed from the SIP are replaced with new control measures that achieve equivalent or greater emissions reductions. Thus, a 110(l) analysis would generally need to show that the SIP revision, or, in this case, a potential SIP submission replacing an existing FIP, will not interfere with any area's ability to continue to attain or maintain the affected NAAQS or other CAA requirements. The EPA further has interpreted section 110(l) as requiring such substitute measures to be quantifiable, permanent, and enforceable, among other considerations. For section 110(l) purposes, ''permanent'' means the state cannot modify or remove the substitute measure without EPA review and approval. Second, the state could conduct air quality modeling or develop an attainment or maintenance demonstration based on the EPA's most recent technical guidance to show that, even without the control measure or with the control measure in its modified form, significant contribution from the state would continue to be prohibited as the Act requires. As discussed further in this section, for purposes of interstate ozone transport, such an analysis entails important questions of consistency and equity among states for resolving air quality problems that the EPA would need to carefully evaluate.[405]

[405] For instance, future circumstances in which the receptor or receptors to which a state is linked come fully into attainment or to which the upwind state's linkage drops below 1 percent of the NAAQS would likely not, solely on those grounds, be sufficient to relax transport requirements established by the FIP or justify approving a less stringent SIP. First, the emissions reductions achieved by the FIP are part of the reason that a receptor may come into attainment or a linkage may drop below 1 percent of the NAAQS. Simply

Continued

In the EPA's experience implementing the CAA criteria pollutant program, reductions arising from the good neighbor provision have been critically important to the improvement of air quality in downwind areas struggling with attainment and maintenance of the NAAQS, and states' reliance on good neighbor FIP reductions will need to be taken into account in any replacement SIP. In order for a nonattainment area to be redesignated to attainment, the CAA requires not only that an area attain the standard, but also the Administrator must determine ''that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions.'' CAA section 107(d)(3)(E)(i) and (iii). Many nonattainment areas across the country that have attained various $PM_{2.5}$ and ozone NAAQS have done so in part due to the imposition of Federal good neighbor emissions control measures, and, per CAA section 107(d)(3)(E)(iii), states have specifically relied on the emissions reductions required by those programs in order to be redesignated to attainment. *See, e.g.,* 84 FR 8422, 8425 (March 8, 2019) (noting that ''[a]t least 140 EPA final actions redesignating areas in 20 states to attainment with an ozone NAAQS or a fine particulate matter ($PM_{2.5}$) NAAQS—because NO_X is a precursor to $PM_{2.5}$ as well as ozone—have relied in part on the NO_X SIP Call's emissions reductions''); *see also Sierra Club* v. *EPA,* 774 F.3d 383, 397–99 (7th Cir. 2014) (upholding EPA's approval of a redesignation, and specifically EPA's determination that reductions from Federal good neighbor transport trading programs could reasonably be considered ''permanent and enforceable'' under the statute); *Sierra Club* v. *EPA,* 793 F.3d 656, 665–68 (6th Cir. 2015) (same). States seeking area redesignations are also required under CAA section 107(d)(3)(E)(iv) to develop revisions to their state implementation plans that provide for maintenance of the NAAQS. In so doing, states develop air quality modeling, in which they project future air quality based on emissions inputs that account for enforceable emissions reductions, or states project emissions in the future relative to emissions in an attainment year, showing that the future emissions (which, again, account for on-the-books, enforceable emissions limits) do not exceed emissions in the baseline attainment year. *See* ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' Memo from John Calcagni to EPA Regions, September 4, 1992, at 9. Reductions required by Federal good neighbor programs may therefore also be relied upon by states seeking area redesignations in the context of how states demonstrate that areas will maintain the NAAQS.

We anticipate that air quality in areas struggling to attain and maintain the 2015 ozone NAAQS will improve due to the emissions reductions required by EPA's FIP. We also anticipate that, consistent with EPA's historical experience implementing the NAAQS and acting on state requests for nonattainment area redesignations, emissions reductions associated with EPA's transport FIP for the 2015 ozone NAAQS are likely to be a critical component in those requests for redesignation. Where states have relied and are relying on the FIP's reductions in order to attain and maintain the NAAQS, EPA will look very critically at any replacement SIP that appears to fall short of equivalent emissions reductions—in terms of the level of reductions or the permanence of those reductions.

Finally, we disagree with commenters that the absence of fixed, mass-based emissions budgets for each state make it impossible to replace the FIP with an equivalent SIP. In the case of the trading program enhancements for EGUs, the EPA recognizes that the dynamic budgeting methodology will generally function to impose a continuous incentive on relevant EGUs to continue to implement the emissions control strategies determined at Step 3. Further, the backstop rate and banking recalibration enhancements also are designed to ensure that EGUs implement emissions controls consistent with Step 3 determinations on a continuous basis throughout each ozone season. As explained in section V.D.4 of this document, these aspects of the trading program do not in themselves introduce an overcontrol concern. Nonetheless, consistent with the more general principles discussed in this section with respect to the potential bases on which states may replace the FIP with SIPs, we reserve judgment at this time on whether some future demonstration could successfully establish that revision of the FIP or its replacement with a SIP could be acceptable even if the way that significant contribution is eliminated is through means that differ from the trading program enhancements included for EGUs in this action. As discussed further in this section, a state may choose to withdraw its EGUs from the trading program and instead subject those EGUs to daily emissions rates commensurate with installation and optimization of state-of-the-art combustion and post-combustion controls as the EPA determined at Step 3. Likewise, states are free to explore an alternative set of emissions controls on non-EGU industrial sources (or other sources in the state), so long as they can demonstrate that an equivalent amount of emissions is eliminated. In any case, we need not resolve these questions here. The EPA, in promulgating a FIP, is not obligated to identify each way a state could replace it with a SIP revision. Several options are discussed further in this section, and, as always, EPA Regional Offices will work closely with states who wish to explore these options or other alternatives.

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA is finalizing the option 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. A state must submit a letter to EPA by August 4, 2023, 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 September 5, 2023. 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

removing emissions control requirements the moment this occurs is illogical, since those reductions are part of the solution by which the attaining air quality was achieved or the linkage was resolved. *See* CAA section 107(d)(3)(E)(iii) (areas cannot be redesignated unless based on permanent and enforceable reductions); *see also Wisconsin,* 938 F.3d at 324–25 (explaining that upwind states are held to a contribution standard, not a but-for causation standard and thus cannot escape good neighbor obligations on the basis that other emissions ''cause'' the NAAQS to be exceeded). There is a risk of inconsistency and inequity in removing any requirements in this manner in that any increase in emissions that could occur in one upwind state would likely need to be reviewed in relation to the obligations other upwind states would continue to meet. Further, any such relaxation in upwind state requirements could then unreasonably shift the burden for maintaining air quality onto the downwind states where receptors are located. These issues may entail complex state- or case-specific analyses that would need to be evaluated at the time such a SIP revision is submitted; these issues are not ripe for resolution in this action.

followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA received no comments 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 and is finalizing the provisions as proposed.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, 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. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

In this final rule, the EPA is removing the previous regulatory text defining specific options for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines. These options for expanding trading program applicability through SIP revisions have been available to states since the start of the CSAPR trading programs for small EGUs and since the CSAPR Update for large non-EGU boilers and combustion turbines, and no state has chosen to use the SIP process for this purpose. Additionally, the EPA did not receive comment supporting these expansion options during the comment period for this rule. The EPA is finalizing a methodology for updating the affected EGU portion of the budget in this rule, and the regulatory text defining the applicability expansion to non-EGUs did not include a mechanism for updating the incremental non-EGU portion of a state's budget based on changes over time of the non-EGU fleet; therefore, continuation of the option to expand applicability to certain non-EGUs subject to the NO_X SIP Call would be inconsistent with the trading program as applied to EGUs in this rule.

However, the EPA recognizes that states may seek to include non-EGUs covered in this action in an emissions trading program, subject to important considerations to ensure equivalency in emissions reductions is maintained. While the EPA is not offering specific regulatory text to implement an option to expand the trading program applicability, a state could submit a SIP to expand the CSAPR NO_X Ozone Season Group 3 Trading Program applicability, which the EPA would evaluate on a case-by-case basis. The SIP revision would need to address critical program elements, and include: (1) high-quality baseline data, (2) ongoing Part 75 monitoring, and (3) provisions to update the non-EGU portion of the budget to appropriately reflect changes to the fleet over time.

For states that want to modify the EPA-determined default allocations, the EPA proposed that a state could submit a SIP revision that makes changes only to that provision 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. 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 the 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 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 deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024. Similarly, a state can 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 EPA recordation of the allocations by July 1, 2025.

The EPA received no comment on the option to replace certain allowance allocation provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, 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 can submit a SIP revision that makes changes only to modify the EPA-determined default allocations and that adopts 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 previously, 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 chooses to replace the 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. Also, for the same reasons discussed with respect to the abbreviated SIP option, the EPA is removing the option for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines.

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 is December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024, and so on.

The EPA received no comment on the 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 and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

4. SIP Revisions That Do Not Use the 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. 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 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 2027 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 background information on considerations for replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU or Industrial Source Control Requirements

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. To replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The state SIP submittal must demonstrate that the emissions reductions required by the SIP would continue to ensure that significant contribution from that state has been eliminated through permanent and enforceable measures. 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.

The most straightforward method for a state to submit a presumptively approvable SIP revision to replace the non-EGU portion of the FIPs 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 VI.C of this document.

Comment: One commenter stated that they believed EPA's assertion in the proposal that any SIP submittal would have to achieve equal or greater reductions for non-EGUs than the FIP was unlawful. The commenter asserted that a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP).

Response: The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP; this is discussed in response to comments earlier in this section. For example, some states may desire to include non-EGUs in a trading program. This may be possible subject to taking into account a number of considerations as discussed earlier in this section to ensure equivalency between the different approaches. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP to be presumptively approvable. The EPA anticipates that such emissions reductions strategies would have to achieve reductions equivalent to or 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 by the 2026 ozone season.

EPA further acknowledges that a demonstration of equivalency using other control strategies is complicated by the fact that the final emissions limits for non-EGU sources are generally unit-specific and expressed in a variety of forms; comparative analysis with alternative control requirements to determine equivalency would need to take this into account. Similarly, we recognize that the emissions trading program for EGUs in this action includes a number of enhancements to ensure that the Step 3 determination of which emissions are ''significant'' and must be eliminated continues to be implemented over time. Although there is not a fixed, mass-based emissions budget established for each state in this action, there are other objective metrics that could guide states in developing replacement SIPs. For example, for non-EGUs, states may choose to conduct an analysis of their industrial stationary sources and present an alternative set of emissions limits applying to specific units that it believes would achieve an equivalent level of emissions reduction. States could apply cost-effectiveness thresholds for emissions control technologies that could be applied to establish that some alternative emissions control strategy results in equivalent or greater improvement at downwind receptors. The EPA anticipates that such a comparison may entail review of both baseline emissions information and growth projections between the different sets of units to ensure that a truly equivalent or greater degree of emissions reduction is achieved; additionality and emissions shifting potential may also need to be considered. We note that the CAMx policy case run for 2026 provides a benchmark for assessing the level of air quality improvement anticipated at receptors with implementation of the FIP. This data may be of use to states as part of a demonstration that a replacement SIP achieves an equivalent or greater level of air quality improvement to the FIP; however, the use of such modeling in such a demonstration would need to be more fully evaluated at the time of such a SIP revision.

In all cases, a SIP submitted by a state to replace the non-EGU components of the FIPs would very likely 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 very likely be insufficient; see discussion in response to comments earlier in this section. 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.

E. Title V Permitting

This final 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.[406] 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 final rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements and already possess a title V operating permit. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the FIPs finalized in this action would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, EGU requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability, and for non-EGUs, the emissions limits and compliance requirements are, to the extent relevant to each source, ''applicable requirements'' that must be addressed in the permits.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the 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)), significant modifications (40 CFR 70.7(e)(4)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[407] 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.

1. Title V Permitting Considerations for EGUs

Title V of the CAA establishes the basic requirements for state title V 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 final 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 those rules would comply with title V and its regulations.[408] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this rule, identical title V compliance provisions will apply with respect to 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 final 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 final rule would also continue to support the means by which a source in the final 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 40 CFR part 75, an excepted monitoring system under appendices D and E to 40 CFR part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of 40 CFR 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 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.[409] 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

[406] Part 70 addresses requirements for state title V programs, and part 71 governs the Federal title V program.

[407] 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).

[408] 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.*

[409] *Id.*

governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, 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.[410] The EPA maintains the same approach for the trading program in this final rule.

2. Title V Permitting Considerations for Industrial Stationary Sources

For non-EGU sources, affected sources will need to work with their local, state, or tribal permitting authority to determine if the new applicable requirements should be incorporated into their existing title V permit under the reopening for cause, significant modification, or permit renewal procedures of the approved permitting program. Title V permits for existing sources will need to be updated to include the applicable requirements of this final rule and any necessary preconstruction permits obtained in order to comply with this final rule.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

Sources in states affected by both the NO_X SIP Call for the 1979 ozone NAAQS and the requirements established in this final rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. With respect to EGUs larger than 25 MW, in this rule the EPA is requiring NO_X ozone season emissions reductions from these sources 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. The emissions reductions required under this rule are therefore sufficient to satisfy the emissions reduction requirements under the NO_X SIP Call for these large EGUs.

With respect to the large non-EGU boilers and combustion turbines that formerly participated in the NO_X Budget Trading Program under the NO_X SIP Call, the EPA provided options under both the CSAPR Update and the Revised CSAPR Update for states to address these sources' ongoing NO_X SIP Call requirements by expanding applicability of the relevant CSAPR trading programs for ozone season NO_X emissions to include the sources, and no state chose to use these options. As discussed in sections VI.D.2 and VI.D.3, in this rule the EPA is removing the previous regulatory text defining specific options for states to expand trading program applicability to include these sources and instead will evaluate any SIP revisions seeking to include these sources in the Group 3 trading program on a case-by-case basis.[411]

2. Acid Rain Program

This rule does not affect any SO_2 and NO_X requirements under the Acid Rain Program, which are established separately under 40 CFR parts 72 through 78 and will continue to apply independently of this rule's provisions. Sources subject to the Acid Rain Program will continue to be required to comply with all requirements of that program, including the requirement to hold sufficient allowances issued under the Acid Rain Program to cover their SO_2 emissions after the end of each control period.

3. Other CSAPR Trading Programs

This rule does 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. Sources subject to any of the CSAPR trading programs will continue to be required to comply with all requirements of all such trading programs to which they are subject, including the requirement to hold sufficient allowances issued under the respective programs to cover emissions after the end of each control period.

The EPA also notes that where a state's good neighbor obligations with respect to the 1997 ozone NAAQS or the 2008 ozone NAAQS have previously been met by participation of the state's large EGUs in the CSAPR NO_X Ozone Season Group 2 Trading Program (or earlier by the CSAPR NO_X Ozone Season Group 1 Trading Program), the EPA will deem those obligations to be satisfied by the participation of the same sources in the CSAPR NO_X Ozone Season Group 3 Trading Program. Specifically, for all states covered by the Group 3 trading program under this rule except Minnesota, Nevada, and Utah, participation of the state's EGUs in the Group 3 trading program will be deemed to satisfy not only the EGU-related portion of the state's good neighbor obligations with respect to the 2015 ozone NAAQS but also the state's good neighbor obligations with respect to the 2008 ozone NAAQS. In addition, for Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Wisconsin, participation of the state's EGUs in the Group 3 trading program will also be deemed to satisfy the state's good neighbor obligations with respect to the 1997 ozone NAAQS.[412]

VII. 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 final 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 X.J of this final rule and analytical results are available in Chapter 7 of the *RIA*. This analysis is being provided for informational purposes only.

A. Introduction

Executive Order 12898 directs EPA 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.[413] Additionally, Executive

[410] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[411] Only one NO_X SIP Call state—Tennessee—continues to participate in the Group 2 trading program, and the EPA has already approved other SIP provisions addressing the ongoing NO_X SIP Call obligations for Tennessee's large non-EGU boilers and combustion turbines. *See* 84 FR 7998 (March 6, 2019); 86 FR 12092 (March 2, 2021).

[412] For the remaining state transitioning from the Group 2 trading program to the Group 3 trading program under this rule—Texas—as well as the remaining states that transitioned from the Group 2 trading program to the Group 3 trading program under the Revised CSAPR Update—Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—participation of the states' EGUs in the Group 3 trading program as required by the CSAPR Update was addressing good neighbor obligations of the states with respect to only the 2008 ozone NAAQS, not the 1997 ozone NAAQS. *See* 81 FR 74523–74526.

[413] 59 FR 7629, February 16, 1994.

Order 13985 is intended to advance racial equity and support underserved communities through Federal Government actions.[414] 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. The 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.''[415] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

B. Analytical Considerations

The EPA's environmental justice (EJ) technical guidance[416] states that:

The analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?

2. Are there potential EJ 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 EJ concerns created or mitigated compared to the baseline?

To address these questions in the 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 final 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.,* residence of historically red lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated.

For the final rule, we employ two types of analytics to respond to the previous 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).[417] 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, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standard (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state level emissions data paired with facility-level baseline emissions, and provided at a resolution of $12km^2$. Additionally, here we focus on air quality changes due to this final rulemaking and infer post-policy exposure burden impacts.

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 information about ozone concentration changes 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); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups (section 7.4). 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 final rule. However, such analyses are less useful here as they do not account for the potential impacts of this final rule on long-range concentration changes. Baseline demographic proximity analysis presented in the *RIA* suggest that larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Relating these results to question 1 from section 7.2 of the *RIA,* we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* NO_2) for certain population groups of concern in the baseline. However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results do not in themselves demonstrate disproportionate impacts of affected facilities in the baseline and should not be interpreted as a direct measure of exposure or impact.

Whereas proximity analyses are limited to evaluating the representativeness of populations residing nearby affected facilities, the ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions. Even though both the proximity and exposure analyses can potentially 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.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden 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 ozone and $PM_{2.5}$ analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less

[414] 86 FR 7009, January 20, 2021.

[415] *https://www.epa.gov/environmentaljustice.*

[416] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

[417] 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).

educated, and children may experience somewhat higher ozone and $PM_{2.5}$ concentrations compared to the national average. Therefore, also in response to question 1, there likely are potential environmental justice concerns associated with ozone and $PM_{2.5}$ 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. In addition, we infer that disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration due to similar modeled concentration reductions across population demographics (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[418]

C. Outreach and Engagement

Prior to proposal, the EPA hosted an outreach webinar with environmental justice stakeholders to share information about the proposed rule and solicit feedback about potential environmental justice considerations. The webinar was attended by representatives of state governments, federally recognized tribes, environmental NGOs, higher education institutions, industry, and the EPA.[419] Participants were invited to comment on pre-proposal environmental justice considerations during the webinar or submit written comments to a pre-proposal non-regulatory docket.

After proposal, the EPA opened a public comment period to invite the public to submit written comments to the regulatory docket for this rulemaking.[420] The EPA also invited the public to participate in a public hearing held on April 21, 2022. A transcript of the public hearing is available in the docket for this rulemaking. Additionally, on March 31, 2022, the EPA hosted an informational webinar with non-governmental groups and environmental justice stakeholders to answer questions and share information about the proposed rule. A record of this webinar, including the informational power point shared at the webinar is available in the docket for this rulemaking.

VIII. Costs, Benefits, and Other Impacts of the Final Rule

In the *RIA* for the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, the EPA estimated the health and climate benefits, compliance costs, and emissions changes that may result from the final rule for the analysis period 2023 to 2042. The estimated health and climate benefits and compliance costs are presented in detail in this *RIA*. The EPA notes that for EGUs the estimated benefits and compliance costs are directly associated with fully operating existing SCRs during ozone season; fully operating existing SNCRs during ozone season; installing state-of-the-art combustion controls; imposing a backstop emissions rate on certain units that lack SCR controls; and installing SCR and SNCR post-combustion controls. The EPA also notes that for non-EGUs the estimated health benefits and compliance costs are directly associated with installing controls to meet the NO_X emissions requirements presented in section I.B of this document.

For EGUs, the EPA analyzed this action's emissions 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. The EPA also analyzed a more and a less stringent alternative. The more and less stringent alternatives differ from the rule in that they set different NO_X ozone season emissions budgets for the affected EGUs and different dates for large, coal-fired EGUs' compliance with the backstop emissions rate.

For non-EGUs, the EPA developed an analytical framework to determine which industries and emissions unit types to include in a proposed Transport FIP for the 2015 ozone NAAQS transport obligations. A February 28, 2022 memorandum, titled "Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026," documents the analytical framework used to identify industries and emissions unit types included in the proposed FIP. To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP. The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. For the non-EGU industries, in the final rule we made some minor changes to the non-EGU emissions units covered, the applicability criteria, as well as provided for facility-wide emissions averaging for engines and for a low-use exemption to eliminate the need to install controls on low-use boilers.

Table VIII–1 provides the projected 2023 through 2027, 2030, 2035, and 2042 EGU NO_X, SO_2, $PM_{2.5}$, and CO_2 emissions 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 VIII–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

	Final rule	Less stringent alternative	More stringent alternative
2023:			
NO_X (ozone season)	10,000	10,000	10,000
NO_X (annual)	15,000	15,000	15,000
SO_2 (annual)	1,000	3,000	1,000
CO_2 (annual, thousand metric tons)	....	....	....

[418] Please note, exposure results should not be extrapolated to other air pollutant. Detailed environmental justice analytical results can be found in Chapter 7 of the RIA.

[419] This does not constitute EPA's tribal consultation under E.O. 13175, which is described in section XI.F of this rule.

[420] Comments and responses regarding environmental justice considerations are available in Section 6 of the *RTC* document for this rulemaking.

TABLE VIII–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

	Final rule	Less stringent alternative	More stringent alternative
$PM_{2.5}$ (annual)			
2024:			
NO_X (ozone season)	21,000	10,000	33,000
NO_X (annual)	25,000	15,000	57,000
SO_2 (annual)	19,000	5,000	59,000
CO_2 (annual, thousand metric tons)	10,000	4,000	20,000
$PM_{2.5}$ (annual)	1,000		1,000
2025:			
NO_X (ozone season)	32,000	10,000	56,000
NO_X (annual)	35,000	15,000	99,000
SO_2 (annual)	38,000	7,000	118,000
CO_2 (annual, thousand metric tons)	21,000	8,000	40,000
$PM_{2.5}$ (annual)	2,000	1,000	2,000
2026:			
NO_X (ozone season)	25,000	8,000	49,000
NO_X (annual)	29,000	12,000	88,000
SO_2 (annual)	29,000	5,000	104,000
CO_2 (annual, thousand metric tons)	16,000	6,000	34,000
$PM_{2.5}$ (annual)	1,000		2,000
2027:			
NO_X (ozone season)	19,000	6,000	43,000
NO_X (annual)	22,000	9,000	78,000
SO_2 (annual)	21,000	4,000	91,000
CO_2 (annual, thousand metric tons)	10,000	3,000	28,000
$PM_{2.5}$ (annual)	1,000		2,000
2030:			
NO_X (ozone season)	34,000	33,000	31,000
NO_X (annual)	62,000	59,000	50,000
SO_2 (annual)	93,000	98,000	51,000
CO_2 (annual, thousand metric tons)	26,000	23,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2035:			
NO_X (ozone season)	29,000	30,000	27,000
NO_X (annual)	46,000	46,000	41,000
SO_2 (annual)	21,000	19,000	15,000
CO_2 (annual, thousand metric tons)	16,000	15,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2042:			
NO_X (ozone season)	22,000	22,000	22,000
NO_X (annual)	23,000	22,000	21,000
SO_2 (annual)	15,000	15,000	7,000
CO_2 (annual, thousand metric tons)	9,000	8,000	4,000
$PM_{2.5}$ (annual).			

Emissions changes for NO_X, SO_2, and $PM_{2.5}$ are in tons.

Table VIII–2 provides a summary of the ozone season NO_X emissions for non-EGUs for the 20 states subject to the non-EGU emissions requirements starting in 2026, along with the estimated ozone season NO_X reductions for 2026 for the 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 VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
AR	8,790	1,546	457	1,690
CA	16,562	1,600	1,432	4,346
IL	15,821	2,311	751	2,991
IN	16,673	1,976	1,352	3,428
KY	10,134	2,665	583	3,120
LA	40,954	7,142	1,869	7,687
MD	2,818	157	147	1,145
MI	20,576	2,985	760	5,087
MO	11,237	2,065	579	4,716
MS	9,763	2,499	507	2,650

TABLE VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES—Continued

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
NJ	2,078	242	242	258
NV [421]	2,544	0	0	0
NY	5,363	958	726	1,447
OH	18,000	3,105	1,031	4,006
OK	26,786	4,388	1,376	5,276
PA	14,919	2,184	1,656	4,550
TX	61,099	4,691	1,880	9,963
UT	4,232	252	52	615
VA	7,757	2,200	978	2,652
WV	6,318	1,649	408	2,100
Totals	302,425	44,616	16,786	67,728

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

For EGUs, the EPA analyzed ozone season NO_X emissions 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 prepared an assessment summarized in the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* and the memorandum includes estimated emissions reductions by state for the rule.[421]

Table VIII–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 requirements for non-EGUs. The costs presented in Table VIII–3 do not include monitoring and reporting costs, which EPA summarizes in section X.B.2 of this document. The monitoring and reporting costs presented in section X.B.2 are $0.35 million per year for EGUs and $3.8 million per year for non-EGUs. For EGUs, compliance costs are negative in 2026. 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.[422] 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 the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* see Chapter 4, sections 4.4 and 4.5.4 of the *RIA.*

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042

	Final rule	Less-stringent alternative	More-stringent alternative
2023:			
EGUs	57	56	49
Non-EGUs	....	....	....
Total	57	56	49
2024:			
EGUs	(5)	(35)	840
Non-EGUs	....	....	....
Total	(5)	(35)	840
2025:			
EGUs	(5)	(35)	840
Non-EGUs	....	....	....
Total	(5)	(35)	840
2026:			

[421] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. See section III.B.1.d.

[422] As a sensitivity, the EPA re-calculated costs assuming annual costs cannot be negative. This resulted in annualized 2023–42 costs under the final rule increasing from $448.6 million to $449.5 million (less than 1%) and did not change the conclusions of the RIA. See Section 4.5.2 of the RIA for more information.

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
EGUs	(5)	(35)	840
Non-EGUs	570	140	1,300
Total	570	110	2,100
2027:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2028:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2029:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2030:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2031:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2032:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2033:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2034:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2035:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2036:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2037:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2038:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2039:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2040:			
EGUs	820	830	600

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2041:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2042:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900

Tables VIII–4 and VIII–5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. In each of these tables, for each discount rate and regulatory control alternative, two 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 VIII–4—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2023

[95 Percent confidence interval; millions of 2016$] [a b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$100 [$27 to $220] [c] *and* $820 [$91 to $2,100] [d].	$100 [$27 to $220] [c] *and* $810 [$91 to $2,100] [d].	$110 [$28 to $230] [c] *and* $840 [$94 to $2,200] [d].
7%	Ozone Benefits	$93 [$17 to 210] [c] *and* $730 [$75 to $1,900] [d].	$93 [$17 to $210] [c] *and* $730 [$75 to $1,900] [d].	$96 [$18 to $210] [c] *and* $750 [$77 to $2,000] [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 ozone benefits for changes in NO_X for the ozone season. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

TABLE VIII–5—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2026

[95% Confidence interval; millions of 2016$] [a b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$1,100 [$280 to $2,400] [c] *and* $9,400 [$1,000 to $25,000] [d].	$420 [$110 to $900] [c] *and* $3,400 [$380 to $8,900] [d].	$1,900 [470 to $4,000] [c] *and* $15,000 [$1,700 to $40,000] [d].
	PM Benefits	$2,000 [$220 to $5,300] *and* $4,400 [$430 to $12,000].	$530 [$57 to $1,400] *and* $1,100 [$110 to $3,100].	$6,400 [$690 to $17,000] *and* $14,000 [$1,300 to $37,000]
	Ozone plus PM Benefits.	$3,200 [$500 to $7,700] [c] *and* $14,000 [$1,500 to $36,000] [d].	$950 [$160 to $2,300] [c] *and* $4,600 [$490 to $12,000] [d].	$8,300 [$1,200 to $21,000] [c] *and* $29,000 [$3,000 to $77,000] [d].
7%	Ozone Benefits	$1,000 [$180 to $2,300] [c] *and* $8,400 [$850 to $22,000] [d].	$380 [$68 to $850] [c] *and* $3,100 [$310 to $8,100] [d].	$1,700 [$300 to $3,800] [c] *and* $14,000 [$1,400 to $36,000] [d].
	PM Benefits	$1,800 [$190 to $4,700] *and* $3,900 [$380 to $11,000].	470 [$50 to $1,200] *and* $1,000 [$100 to $2,800].	$5,800 [$600 to $15,000] *and* $12,000 [$1,200 to $33,000].
	Ozone plus PM Benefits.	$2,800 [$370 to $7,000] [c] *and* $12,000 [$1,200 to $33,000] [d].	$850 [$120 to $2,100] [c] *and* $4,100 [$410 to $11,000] [d].	$7,500 [$910 to $19,000] [c] *and* $26,000 [$2,600 to $69,000] [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 annual changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026.
[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 VIII–6, VIII–7, and VIII–8, the EPA presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2023, 2026, and 2030, respectively. There are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than ozone and $PM_{2.5}$ that are not quantified. Discussion of the non-monetized health, welfare, and water quality benefits is found in Chapter 5 of the *RIA.* In this action, monetized climate benefits are presented for purposes of providing a complete economic impact analysis under E.O. 12866 and other relevant Executive orders. The estimates of GHG emissions changes and the monetized benefits associated with those changes is not part of the record basis for this action, which is taken to implement the good neighbor provision, CAA section 110(a)(2)(D)(i)(I), for the 2015 ozone NAAQS.

TABLE VIII–6—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2023 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$100 and $820	$100 and $810	$110 and $840.
Climate Benefits	$5	$4	$5.
Total Benefits	$100 and $820	$100 and $820	$110 and $840.
Costs [d]	$57	$56	$49.
Net Benefits	$48 and $760	$48 and $760	$66 and $800.

[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] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–7—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2026 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,200 and $14,000	$950 and $4,600	$8,300 and $29,000.
Climate Benefits	$1,100	$420	$2,100.
Total Benefits	$4,300 and $15,000	$1,400 and $5,000	$10,000 and $31,000.
Costs [d]	$570	$110	$2,100.
Net Benefits	$3,700 and $14,000	$1,300 and $4,900	$8,300 and $29,000.

[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] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–8—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2030 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,400 and $15,000	$1,000 and $4,900	$9,000 and $31,000.
Climate Benefits	$1,500	$1,300	$500.
Total Benefits	$4,900 and $16,000	$2,300 and $6,200	$9,500 and $31,000.
Costs [d]	$1,300	$920	$2,100.
Net Benefits	$3,600 and $15,000	$1,400 and $5,300	$7,400 and $29,000.

[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] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

In addition, Table VIII–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 recommended by OMB's Circular A–4 and are presented in 2016 dollars discounted to 2023.

TABLE VIII–9—MONETIZED ESTIMATED HEALTH AND CLIMATE BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES, 2023 THROUGH 2042

[Millions 2016$, discounted to 2023]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Health benefits				
Final Rule	$200,000	$13,000	$130,000	$12,000
Less Stringent Alternative	67,000	4,500	40,000	3,800
More Stringent Alternative	410,000	28,000	240,000	23,000
Climate Benefits [a]				
Final Rule	15,000	970	15,000	970
Less Stringent Alternative	11,000	770	11,000	770
More Stringent Alternative	14,000	920	14,000	920
Compliance Costs				
Final Rule	14,000	910	9,400	770
Less Stringent Alternative	8,700	590	5,300	500
More Stringent Alternative	25,000	1,700	17,000	1,600
Net Benefits				
Final Rule	200,000	13,000	140,000	12,000
Less Stringent Alternative	70,000	4,700	42,000	4,000
More Stringent Alternative	400,000	27,000	240,000	22,000

[a] Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC–CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

As shown in Table VIII–9, the PV of the monetized health benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

In addition to the analysis of costs and benefits as described above, for the final rule, the EPA was able to conduct a full-scale photochemical grid modeling run of the effects of the ''final rule'' emissions control scenario in 2026. This modeling can be used to estimate the impacts on projected 2026 ozone design values that are expected from the combined EGU and non-EGU control emissions reductions in this final rule. These results do not replace the AQAT-generated estimates used for our Step 3 determinations, and the EPA needed to continue to use AQAT for Step 3 determinations in order to characterize various potential control scenarios to inform these regulatory determinations. Nonetheless, though they differ slightly from the AQAT-generated air quality estimates of the final rule control scenario conducted for purposes of our Step 3 analysis (as presented in section V.D of this document), these results using full-scale photochemical grid modeling complement those estimates and confirm in all cases the regulatory conclusions reached applying AQAT.[423] Appendix 3A of the *RIA* presents the full results of the projected impacts of the final rule control scenario on ozone levels using CAMx. To briefly summarize, the largest reductions in ozone design values at identified receptors are predicted to occur in the Houston-Galveston-Brazoria, Texas area. In this area the reductions from the final rule case range from 0.7 to 0.9 ppb. At most of the receptors in both the Dallas/Ft Worth and the New York/Coastal Connecticut areas the reductions in ozone range from 0.4 to 0.5 ppb. At receptors in Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan, ozone is projected to decline by 0.3 to 0.4 ppb, but by as much as 0.5 ppb at the receptor in Muskegon, MI. Reductions of 0.1 ppb are predicted in the urban and near-urban receptors in Chicago. In the West, ozone reductions just under 0.2 ppb are predicted at receptors in Denver with slightly greater reductions, just above 0.2 ppb, at receptors in Salt Lake City. At receptors in Phoenix, California, El Paso/Las Cruces, and southeast New Mexico the reductions in ozone are predicted to be less than 0.1 ppb.

[423] Note that the EPA's ''overcontrol'' analysis relies primarily on a ''Step 3'' control scenario rather than the ''full geography'' scenario. The CAMx modeling described here captures the effects of the rule as a whole and so is more akin to the ''full geography'' scenario, which the EPA does not believe is the appropriate method for conducting overcontrol analysis. Nonetheless, as explained in the Ozone Transport Policy Analysis Final Rule TSD, the results under either scenario establish no overcontrol, and the CAMx results presented here do not call those conclusions into question.

IX. Summary of Changes to the Regulatory Text for the Federal Implementation Plans and Trading Programs for EGUs

This section describes the amendments to the regulatory text that implement the findings and remedy discussed elsewhere in this rule with respect to EGUs. The primary CFR amendments are 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 are being 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 are being amended to identify certain additional types of appealable decisions of the EPA Administrator under the amended trading program. The provisions to address the transition of the EGUs in certain states from the Group 2 trading program to the Group 3 trading program are implemented in part through revisions to the regulations noted previously 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 being made to the regulations for the other CSAPR trading programs in 40 CFR part 97, subparts AAAAA through EEEEE, for conformity with the amended provisions of the Group 3 trading program, as discussed in section VI.B.13. Documents have been included in the docket for this rule showing all of the 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 in this rulemaking the EPA is establishing new or amended FIP requirements not only for the types of EGUs covered by the trading programs but also for certain types of industrial sources, an amendment to § 52.38(b)(1) clarifies that the trading programs constitute the FIP provisions only for the sources meeting the applicability requirements of the trading programs. A parallel clarification is being 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). The amendments to this paragraph expand the applicability of the Group 3 trading program to sources in the ten additional states that the EPA is adding to the Group 3 trading program starting with the 2023 control period and end the applicability of the Group 2 trading program (with the exception of certain provisions) for sources in seven of the ten states after the 2022 control period, as discussed in section VI.B.2.[424] The paragraphs within § 52.38(b)(2) are being 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 the EPA will no longer administer the state trading programs adopted under those SIP revisions after the 2022 control period is being 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. As in effect before this rule, § 52.38(b)(10), (11), and (12) established 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.[425] As discussed in section VI.D, the EPA is retaining these SIP revision options and is making them available for all states covered by the Group 3 trading program after the geographic expansion. The option under § 52.38(b)(10) to replace allowance allocations for a single control period is being 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 IX.B. The options under § 52.38(b)(11) and (12) to adopt abbreviated or full SIP revisions are being 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).[426] The removal of the previous options for states to expand applicability of the trading programs for ozone season NO_X emissions to certain non-EGUs and smaller EGUs, discussed in sections VI.D.2 and VI.D.3, is accomplished by the removal or revision of multiple paragraphs of § 52.38(b), including most notably the removal of § 52.38(b)(4)(i), (b)(5)(i), (b)(8)(i)–(ii), (b)(9)(i)–(ii), (b)(11)(i)–(iii), and (b)(12)(i)–(iii).

The changes with respect to set-asides and the treatment of units in Indian country discussed in section VI.B.9, although implemented largely through amendments to the Group 3 trading program regulations, are also implemented in part through 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 may establish state-determined allowance allocations is being revised to exclude any allowances in a new unit set-aside or Indian country existing unit set-aside. Second, the text in § 52.38(b)(12)(vi) identifying provisions that states may 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) are being revised to include the provisions of the amended Group 3 trading program addressing allocation and recordation of allowances from all types of set-asides. Finally, 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'' are being revised to account for the fact that at least one covered unit is already located in Indian country not subject to a state's CAA planning authority.

The transitional provisions discussed in sections VI.B.12.b and VI.B.12.c to

[424] Like the previous text of § 52.38(b)(2), the final amended text expressly encompasses sources in Indian country within the respective states' borders.

[425] Revisions to the deadlines for states with approved SIP revisions to submit their state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

[426] 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 can be used under the amended provisions.

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, will necessarily be implemented after the end of the 2022 control period. 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 are being added at § 52.38(b)(14)(iii). Cross-references clarifying that the EPA's allocations of the converted Group 3 allowances are not subject to modification through SIP revisions are also being 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 rule as set forth in § 52.38(b)(2) are being replicated in the state-specific subparts of 40 CFR part 52 for each of the ten states that the EPA is adding to the Group 3 trading program.[427] In each such state-specific CFR subpart, provisions are being 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 are also being 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 seven states that the EPA is removing from the Group 2 trading program, the provisions of the state-specific CFR subparts indicating that sources in the state are required to participate in that trading program are being revised to end that requirement with respect to emissions after 2022, and a further provision is being 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.[428] In addition, for the five 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 are being removed.

No amendments with respect to FIP requirements for EGUs are being made to the state-specific CFR subparts for the twelve states whose sources currently participate in the Group 3 trading program[429] except as needed to update cross-references or to implement the changes related to the treatment of Indian country, as discussed in section IX.D.

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 are being established under the new and amended FIPs in this rulemaking, several sections of the Group 3 trading program regulations are being 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 are being made at §§ 97.1006(c)(3)(i), 97.1030(b)(1), and 97.1034(d)(2)(i), respectively. Revisions identifying the new or revised budgets and new unit set-asides for the control periods after 2022 for all covered states are being made at § 97.1010(a)(1) and (c)(2), respectively.

Each of the enhancements to the Group 3 trading program discussed in section VI.B is also implemented primarily through revisions to the trading program regulations. The dynamic budget-setting process discussed in sections VI.B.1.b.i and VI.B.4 is implemented at § 97.1010(a)(2) through (4), and the associated revised process for determining variability limits and assurance levels discussed in section VI.B.5 is implemented at § 97.1010(e). The Group 3 allowance bank recalibration process discussed in sections VI.B.1.b.ii and VI.B.6 is implemented at § 97.1026(d). The backstop daily NO_X emissions rate component of the primary emissions limitation discussed in sections VI.B.1.c.i and VI.B.7 is 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 and 97.1006(c)(6). The secondary emissions limitation for sources found responsible for exceedances of the assurance levels discussed in sections VI.B.1.c.ii and VI.B.8 is 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 changes relating to set-asides, the treatment of Indian country, and unit-level allowance allocations discussed in section VI.B.9 of this document are implemented through revisions to multiple paragraphs of §§ 97.1010, 97.1011, and 97.1012, 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) address the amounts for each control period of the Indian country existing unit set-asides, new unit set-asides, and Indian country new unit set-asides, respectively.[430] Paragraphs (b) and (d) reflect the establishment of Indian country existing unit set-asides starting with the 2023 control period and the discontinuation of Indian country new unit set-asides after the 2022 control period.

A newly added definition at § 97.1002 for ''coal-derived fuel'' (based on the existing definition in 40 CFR 72.2) helps in implementation of both the backstop daily NO_X emissions rate provisions and the unit-level allocation provisions by clarifying that the provisions apply without regard to how any coal combusted by a unit might have been processed before combustion. Another newly added definition at § 97.1002 for ''historical control period'' helps in implementation of the dynamic budget-setting provisions, the secondary emissions limitation provisions, and the

[427] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1240(d) (Minnesota), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1492 (Nevada), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), 52.2356 (Utah), and 52.2587(e) (Wisconsin).

[428] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), and 52.2587(e) (Wisconsin).

[429] *See* §§ 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).

[430] The former § 97.1011(c), which addresses the relationships of set-asides and variability limits to state trading budgets, is being relocated to § 97.1011(f).

unit-level allocation provisions by facilitating references to data reported by a unit for periods before the unit's entry into the Group 3 trading program.

The revisions to § 97.1011 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 formerly in § 97.1011(a)(1) requiring allocations to existing units to be made in the amounts provided in NODAs issued by the EPA is being 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.[431] This split will 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 process for determining default allocations to existing units of allowances from state trading budgets starting with the 2026 control period is set forth in revised § 97.1011(b), while the former provisions of § 97.1011(b), which concern timing and notice procedures for allocations to new units, are being relocated to § 97.1012. The provisions addressing incorrectly allocated allowances at § 97.1011(c) are being streamlined by relocating the portions applicable to new units to § 97.1012(c). In addition, as discussed in section VI.B.9.d, § 97.1011(c)(5) is being 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 will not be reallocated to other units in the state but instead would be transferred to a surrender account.

The revisions to § 97.1012 retain the section's current focus on allocations to ''new'' units, generally combining the former provisions at § 97.1012 with the former provisions at § 97.1011(b) and (c) that address new units. The text of multiple paragraphs in both § 97.1012(a) and (b) is being revised as needed to reflect the change in treatment of Indian country discussed in section VI.B.9.a, under which the new unit set-asides will 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.[432] The timing and notice provisions in § 97.1012(a)(13) and (b)(13) are relocated from former § 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 revision addressing the disposition of recovered allowances, as discussed in section VI.B.9.d.

The amendments to § 97.1021 implement two distinct sets of changes discussed in sections VI.B.9 and VI.D.1. First, revisions to § 97.1021(b) through (e) replace the previous schedule for recording Group 3 allowances for the 2023 and 2024 control periods established in the August 2022 Recordation Rule with an updated recordation schedule tailored to the effective date of this rule. The updated schedule also eliminates the unused former option for states to provide state-determined allowance allocations for the 2022 control period and establishes a substantively equivalent new option for states to provide state-determined allowance allocations for the 2024 control period. Second, revisions to § 97.1021(g) through (j) begin recordation for Indian country existing unit set-asides starting with allocations for the 2023 control period, modify the text to eliminate references to state-determined allocations of allowances from new unit set-asides, and end recordation for Indian country new unit set-asides after allocations for the 2022 control period.

Implementation of the revisions to the Group 3 trading program is also 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 VI.B.10 of this document are 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 the procedures for apportioning NO_X mass emissions monitored at a common stack among the individual units using the common stack are being 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) is being amended to add calculation of the dynamic budgets to the list of administrative decisions under the trading program regulations that will be appealable under those procedures.

C. Transitional Provisions

As discussed in section VI.B.12, the EPA is establishing several transitional provisions for sources entering the Group 3 trading program. The provisions discussed in section VI.B.12.a of this document, concerning the prorating of state emissions budgets, assurance levels, and unit-level allocations for the 2023 control period, are implemented through the Group 3 trading program regulations. Specifically, the state emissions budgets for the 2023 control period will 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, will be computed under § 97.1010(e) from the prorated state emissions budgets. Unit-level allocations to existing units for the 2023 control period will 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 VI.B.9.b, and will be announced in the notice of data availability issued under § 97.1011(a)(1) and (2) for the 2023 through 2025 control periods.

The remaining transitional provisions are being implemented through the Group 2 trading program regulations.

[431] 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, is being relocated to § 97.1011(a)(3). The former § 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 VI.B.9, and is being removed as obsolete.

[432] Revisions are also being made to the text of § 97.1012(a) and (b) for the control periods in 2021 and 2022 consistent with the 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.

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 VI.B.12.b of this document is implemented at § 97.826(e).[433] 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 are 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 are 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 VI.B.12.c of this document is implemented at § 97.811(e).

Decisions of the Administrator related to the allowance bank creation provisions and the allowance recall provisions are 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 VI.B.13 of this document, the EPA is revising 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 distinguish among units based on whether they are or are not covered by a state's CAA implementation planning authority. The revisions are 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 are 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.

Certain other revisions to the regulatory text in the FIP and trading program regulations are minor simplifications and 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 transitioning out of the Group 2 trading program are being modified to indicate that the amounts are applicable under that program only for control periods through 2022.

Second, as noted in sections VI.D.2 and VI.D.3, the existing options for states subject to the NO_X SIP Call to expand applicability of the Group 2 trading program to include certain non-EGUs and smaller EGUs are being eliminated. While the most directly affected provisions are the provisions setting forth the SIP options at § 52.38(b)(4), (5), (8), (9), (12), and (13), as discussed in section IX.A of this document, the changes also render references to ''base'' units and ''base'' sources in the regulations for the Group 2 trading program and the Group 3 trading program obsolete. Removal of the references to ''base'' units and ''base'' sources affects multiple paragraphs of §§ 97.802, 97.806, 97.825, 97.1002, 97.1006, and 97.1025.

Third, to clarify the regulatory text, the EPA is removing the language in the Group 3 trading program regulations that formerly appeared at §§ 97.1002 (definition of ''common designated representative's assurance level''), 97.1006(c)(2)(iii), 97.1010(d), and 97.1011(a)(1) referencing supplemental amounts of allowances issued for the 2021 control period and associated increments to the 2021 assurance levels (each state's assurance level increment was described as 21 percent of the state's supplemental amount of allowances). In place of the removed language, the EPA is restating the amounts of the 2021 state emissions budgets in § 97.1010(a)(1)(i) so as to include the supplemental amounts of allowances and is restating the amounts of the 2021 variability limits in § 97.1010(e)(1) so as to include the associated assurance level increments. The revised language is substantively equivalent to and simpler than the previous language.

Fourth, in 40 CFR part 75, the EPA is removing obsolete text in § 75.73(c) and (f) to clarify the context for other text being added to the section, as discussed in section IX.B of this document.

Fifth, in 40 CFR part 52, the EPA is adding §§ 52.38(a)(7)(iii) and 52.39(k)(3) to clarify in §§ 52.38 and 52.39 that the Allowance Management System housekeeping provisions added by the Revised CSAPR Update at §§ 97.426(c), 97.626(c), and 97.726(c) in the regulations for the CSAPR NO_X Annual, SO_2 Group 1, and SO_2 Group 2 trading programs, respectively, continue to apply after the sources in a given state have been removed from the programs, consistent with the text of the latter provisions.

Finally, the EPA is updating cross-references throughout 40 CFR parts 52 and 97 for consistency with the other amendments being made in this rulemaking.

X. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive orders (''E.O.'') can be found at *https://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 action is a significant regulatory action within the scope of section 3(f)(1) of Executive Order 12866 that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to Executive Order 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452–R–23–001], is available in the docket and is briefly summarized in section VIII of this document.

B. Paperwork Reduction Act (PRA)

1. Information Collection Request for Electric Generating Units

The information collection activities in this 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. The EPA has placed a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The EPA is finalizing an information collection request (ICR), related specifically to electric generating units (EGU), for the Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards. The 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 amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana,

[433] The provision formerly at § 97.826(e)(1) is being relocated to § 97.826(f)(1), and the provision formerly at § 97.826(e)(2) is being removed as no longer necessary.

Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) would remain. Additionally, EGU sources in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, 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 three states not currently covered by any CSAPR NO_X ozone season trading program would join the revised Group 3 trading program: Minnesota, Nevada, and Utah. In total, EGU sources in 22 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 emissions 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 the CSAPR NO_X Ozone Group 2 trading programs, the reporting requirements will remain identical so there will be no incremental burden or cost. Certain sources currently reporting data will be subject to additional emissions reporting requirements under the rule requiring these sources to make a one-time monitoring plan and DAHS update. These sources include those with a common stack configuration and/or those that are large, coal-fired EGUs. Additionally, sources with a common stack configuration have the option to install additional monitoring equipment to measure emissions at each individual unit within the facility, and for purposes of estimating information collection costs and burden, the EPA assumes certain sources will utilize this option. Finally, the assessment of incremental cost and burden are required for those sources in the three 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 Nevada and Utah are already reporting data as part of the Acid Rain Program, thus only requiring a monitoring plan and DAHS update as well. There are a small number of sources in Nevada and Utah that do not report emissions data to the EPA under 40 CFR part 75 and will need to implement a Part 75 monitoring methodology which includes burdens related to installation, certification, and necessary updates.

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: The EPA estimates that there would be 120 industry respondents.

Frequency of response: on occasion, quarterly, and annually.

Total estimated additional burden: 2,289 hours (per year). Burden is defined at 5 CFR 1320.03(b).

Total estimated additional cost: \$356,623 (per year); includes \$182,379 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. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

2. Information Collection Request for Non-Electric Generating Units

The information collection activities in this final 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 2705.02. 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. 2705.02 is a new request and it addresses the burden associated with new regulatory requirements under the final rule. Owners and operators of certain non-Electric Generating Unit (non-EGU) industry stationary sources will potentially modify or install new emissions controls and associated monitoring systems to meet the nitrogen oxides (NO_X) emissions limits of this final rule. The burden in this ICR reflects the new monitoring, calibrating, recordkeeping, reporting and testing activities required of covered industrial sources. This information is being collected to assure compliance with the final 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 the EPA, in accordance with 40 CFR chapter I, part 2, subpart B, shall be maintained appropriately (see 40 CFR part 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 boilers in Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

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 final rule, titled ''Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards.''

Estimated number of respondents: 3,328.

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 Tables 1 through 18. 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 pipeline engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on an annual basis.

Total estimated burden: 11,481 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $3,823,000 (average per year); includes $2,400,000 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. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses, which includes EGUs and non-EGUs and are described in more detail below. In 2026, the EPA identified a total of 29 small entities affected by the rule. Of these, 2 small entities may experience costs of greater than 1 percent of revenues. In 2026 for EGUs, the EPA identified 19 small entities. The EPA's decision to exclude units smaller than 25 MW capacity from the final rule, and exclusion of uncontrolled units smaller than 100 MW from backstop emissions rates 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 ten small entities, and two small entities are estimated to have a cost-to-sales impact between 1.7 and 2.4 percent of their revenues.

The Agency has not determined that a significant number of small entities potentially affected by the rule will have compliance costs greater than 1 percent of annual revenues during the compliance period. The EPA has concluded that there will be no significant economic impact on a substantial number of small entities (No SISNOSE) for this 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 action contains no unfunded Federal mandate for State, local, or Tribal governments as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local, or Tribal government. This action contains a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more in any one year for the private sector. Accordingly, the costs and benefits associated with this action are discussed in section VIII of this preamble and in the *RIA,* which is in the docket for this rule. Additional details are presented in the *RIA.* This action is not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final action has tribal implications. However, it would neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA is finalizing a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The EPA is promulgating FIP requirements to eliminate interstate transport of ozone precursors from these 23 states. Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final 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. The EPA's determinations in this regard are described further in section III.C.2 of this document, *Application of Rule in Indian Country and Necessary or Appropriate Finding.* The EPA finds that all covered 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. To the EPA's knowledge, only one covered 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 final action has tribal implication because of the extension of FIP requirements into Indian country and because, in general, tribes have a vested interest in how this final rule would affect air quality.

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 issued tribal consultation letters addressed to 574 tribes in February 2022 after the proposed rule was signed. The EPA received no further requests to facilitate additional tribal consultation for the final 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 and 6 of the *RIA.* The EPA believes that the ozone-related benefits, $PM_{2.5}$-related benefits, and CO_2- related benefits from this final rule will further improve children's health. Additionally, the ozone and $PM_{2.5}$ EJ exposure analyses in Chapter 7 of the *RIA* suggests that nationally, children (ages 0–17) will experience at least as great a reduction in ozone and $PM_{2.5}$ exposures as adults (ages 18–64) in 2023 and 2026 under all regulatory alternatives of this 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. The EPA has prepared a Statement of Energy Effects for the final regulatory control alternative as follows. The Agency estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in the 2025 run year, a 4 percent reduction (28 GWh) in coal-fired electricity generation, a 2 percent increase (21 GWh) in natural gas-fired electricity generation, and a 1 percent increase (8 GWh) in renewable electricity generation as a result of this final rule. The 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 rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or indigenous peoples) and low-income populations.

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. The documentation for this decision is contained in section VII of this document, *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement,* and in Chapter 7, *Environmental Justice Impacts* of the *RIA,* which is in the public document. Briefly, proximity demographic analyses found larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Considering the known limitations of proximity analyses, including the inability to assess policy-specific impacts, we also performed analysis of baseline EJ ozone and $PM_{2.5}$ exposures. Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indians may also experience disproportionately higher ozone concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples. Specifically, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration as compared to the baseline. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration, due to similar modeled concentration reductions across population demographics. Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in many areas, including in ozone nonattainment areas, and thus mitigate some pre-existing health risks across all populations evaluated.

The EPA additionally identified and addressed environmental justice concerns by providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action through outreach activities conducted by the Agency. The information supporting this Executive order review is contained in section VII of this document.

K. Congressional Review Act

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. Because this action falls within the definition provided by 5 U.S.C. 804(2), the rule's effective date is consistent with 5 U.S.C. 801(a)(3).

L. 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 D.C. Circuit: (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions 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 the EPA complete discretion whether to invoke the exception in (ii).[434]

[434] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Continued

This rulemaking is ''nationally applicable'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is applying a uniform legal interpretation and common, nationwide analytical methods with respect to the requirements of CAA section 110(a)(2)(D)(i)(I) concerning interstate transport of pollution (*i.e.,* ''good neighbor'' requirements) to promulgate FIPs that satisfy these requirements for the 2015 ozone NAAQS. Based on these analyses, the EPA is promulgating FIPs for 23 states located across a wide geographic area in eight of the ten EPA regions and ten Federal judicial circuits. Given that this action addresses implementation of the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I) in a large number of states located across the country, and given the interdependent nature of interstate pollution transport and the common core of knowledge and analysis involved in promulgating these FIPs, this is a ''nationally applicable'' action 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 is exercising 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). In this final action, the EPA is interpreting and applying section 110(a)(2)(d)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental U.S. In particular, the EPA is applying here the same, nationally consistent 4-step framework for assessing good neighbor obligations for the 2015 ozone NAAQS that it has applied in other nationally applicable rulemakings, such as CSAPR, the CSAPR Update, and the Revised CSAPR Update. The EPA is relying on the results from nationwide photochemical grid modeling using a 2016 base year and 2023 projection year as the primary basis for its assessment of air quality conditions and pollution contribution levels at Step 1 and Step 2 of that 4-step framework and applying a nationally uniform approach to the identification of nonattainment and maintenance receptors across the entire geographic area covered by this final rule.[435]

The Administrator finds that this is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to the CAA's mandate concerning interstate transport of ozone pollution constitutes the best use of agency resources. The EPA's responses to comments on the appropriate venue for petitions for review are contained in section 1.10 of the *RTC* document.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by August 4, 2023.

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, promulgates new Federal implementation plans pursuant to the authority of section 110(c). To the extent any portion of this final action is not expressly identified under section 307(d)(1)(B), 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'').

Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[435] 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.

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 emissions monitoring, Electric power plants, 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 S. 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 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 subpart AAAAA, except'';
■ b. In paragraph (a)(3) introductory text:
■ i. Removing ''(a)(2)(i) or (ii)'' and adding in its place ''(a)(2)''; and
■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ c. In paragraph (a)(3)(i), removing ''State and'' and adding in its place

"State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";

■ d. In paragraph (a)(4) introductory text, removing "for the State's sources, and" and adding in its place "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, and";

■ e. Revising table 1 to paragraph (a)(4)(i)(B);

■ f. In paragraph (a)(4)(ii), removing "deadlines for submission of allocations or auction results under paragraphs (a)(4)(i)(B) and (C)" and adding in its place "deadline for submission of allocations or auction results under paragraph (a)(4)(i)(B)";

■ g. 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";

■ h. Revising table 2 to paragraph (a)(5)(i)(B);

■ i. 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";

■ j. 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";

■ k. In paragraph (a)(5)(vi), removing "deadlines for submission of allocations or auction results under paragraphs (a)(5)(i)(B) and (C)" and adding in its place "deadline for submission of allocations or auction results under paragraph (a)(5)(i)(B)";

■ l. Revising paragraphs (a)(6) and (a)(7)(ii);

■ m. Adding paragraph (a)(7)(iii);

■ n. In paragraphs (a)(8)(i) and (ii), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";

■ o. 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:";

■ p. In paragraph (b)(1), removing "year), except" and adding in its place "year) for sources meeting the applicability criteria set forth in subparts BBBBB, EEEEE, and GGGGG, except";

■ q. Redesignating paragraphs (b)(2)(i) and (ii) as paragraphs (b)(2)(i)(A) and (B), respectively, paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and paragraph (b)(2)(v) as paragraph (b)(2)(iii)(A);

■ r. 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, Kansas, and Tennessee.";

■ s. Adding paragraphs (b)(2)(ii)(C) and (b)(2)(iii)(B) and (C);

■ t. In paragraph (b)(3) introductory text:

■ i. Removing "or (ii)"; and

■ ii. Removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";

■ u. In paragraph (b)(3)(i), removing "State and" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";

■ v. Revising paragraph (b)(4) introductory text;

■ w. Removing and reserving paragraph (b)(4)(i);

■ x. Revising table 3 to paragraph (b)(4)(ii)(B) and paragraphs (b)(4)(iii) and (b)(5) introductory text;

■ y. Removing and reserving paragraph (b)(5)(i);

■ z. Revising table 4 to paragraph (b)(5)(ii)(B);

■ aa. 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";

■ bb. 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";

■ cc. Revising paragraphs (b)(5)(vii), (b)(7) introductory text, (b)(7)(i), and (b)(8) introductory text;

■ dd. Removing and reserving paragraphs (b)(8)(i) and (ii);

■ ee. Revising paragraph (b)(8)(iii)(A), table 5 to paragraph (b)(8)(iii)(B), and paragraphs (b)(8)(iv) and (b)(9) introductory text;

■ ff. Removing and reserving paragraphs (b)(9)(i) and (ii);

■ gg. Revising paragraph (b)(9)(iii)(A) and table 6 to paragraph (b)(9)(iii)(B);

■ hh. 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";

■ ii. Revising paragraphs (b)(9)(vii) and (viii), (b)(10) introductory text, (b)(10)(i) and (ii), (b)(10)(v)(A) and (B), and (b)(11) introductory text;

■ jj. Removing and reserving paragraphs (b)(11)(i) and (ii);

■ kk. In paragraph (b)(11)(iii) introductory text, removing "§§ 97.1011(a) and (b)(1) and 97.1012(a)" and adding in its place "§ 97.1011(a)(1)";

■ ll. Revising paragraph (b)(11)(iii)(A);

mm. In paragraph (b)(11)(iii)(B):

■ i. Removing "§ 97.1011(a)" and adding in its place "§ 97.1011(a)(1)"; and

■ ii. Adding "and" after the semicolon;

■ nn. Removing and reserving paragraph (b)(11)(iii)(C);

■ oo. Revising paragraphs (b)(11)(iii)(D), (b)(11)(iv), and (b)(12) introductory text;

■ pp. Removing and reserving paragraphs (b)(12)(i) and (ii);

■ qq. In paragraph (b)(12)(iii) introductory text, removing "§§ 97.1011(a) and (b)(1) and 97.1012(a)" and adding in its place "§ 97.1011(a)(1)";

■ rr. Revising paragraph (b)(12)(iii)(A);

■ ss. In paragraph (b)(12)(iii)(B):

■ i. Removing "§ 97.1011(a)" and adding in its place "§ 97.1011(a)(1)"; and

■ ii. Adding "and" after the semicolon;

■ tt. Removing and reserving paragraph (b)(12)(iii)(C);

■ uu. Revising paragraphs (b)(12)(iii)(D), (b)(12)(vi) through (viii), (b)(13) introductory text, and (b)(13)(i);

■ vv. In paragraph (b)(13)(ii), removing "regulations, including any sources made subject to such regulations pursuant to paragraph (b)(9)(ii) or (b)(12)(ii) of this section, the" and adding in its place "regulations the";

■ ww. 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)";

■ xx. In paragraph (b)(14)(i)(G), removing "§ 97.826(e)" and adding in its place "§ 97.826(f)";

■ yy. Revising paragraphs (b)(14)(ii) and (iii);

■ zz. In paragraph (b)(15)(i), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";

■ aaa. Revising paragraph (b)(15)(ii);

■ bbb. 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:";

■ ccc. In paragraph (b)(16)(i)(A), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";

■ ddd. Revising paragraphs (b)(16)(i)(B) and (C);

■ eee. Redesignating paragraph (b)(16)(ii) as paragraph (b)(16)(ii)(A), and, in newly redesignated paragraph (b)(16)(ii)(A), removing "(b)(2)(iv)" and adding in its place "(b)(2)(ii)(B)";

■ fff. Adding paragraph (b)(16)(ii)(B); and

■ ggg. 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or 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 subject to the State's SIP authority, 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 subpart AAAAA 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 pursuant to paragraph (a)(2)(ii) or (a)(6) of this section of the applicability of subpart AAAAA 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, the following provisions shall continue to apply with regard to all CSAPR NO_X Annual allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of § 97.426(c) of this chapter (concerning the transfer of CSAPR NO_X Annual allowances between certain Allowance Management System accounts under common control).

(B) [Reserved]

* * * * *

(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, 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, 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 August 4, 2023, and in each subsequent year: Minnesota, Nevada, and Utah.

* * * * *

(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 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, 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(4)(ii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(4)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(4)(ii) of this section.

(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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(5)(ii) through (v) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(5)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(5)(ii) of this section.

* * * * *

(7) *State-determined allocations of CSAPR NO_X Ozone Season Group 2 allowances for 2018.* 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 CSAPR NO_X Ozone Season Group 2 allowance allocation provisions replacing the provisions in § 97.811(a) of this chapter 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 for the control period in 2018, a list of CSAPR NO_X Ozone Season Group 2 units and the amount of CSAPR NO_X Ozone Season Group 2 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, 2015;

* * * * *

(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 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, 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
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(8)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(8)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(8)(iii) of this section.

(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
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or 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 §§ 97.802, 97.806(c)(2), and 97.825 and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(9)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(9)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(9)(iii) of this section.

(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 sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for 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 Indian country existing unit set-aside and the new unit set-aside;

* * * * *

(v) * * *

(A) By August 4, 2023, 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 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, 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 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 Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(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; and

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(11)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(11)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(11)(iii) of this section.

(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) * * *

(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 Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(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 any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if before the Administrator's approval of the SIP revision 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 ''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 §§ 97.1002, 97.1006(c)(2), and 97.1025, and further provided that, if and when after the Administrator's approval of the SIP revision 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 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

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(12)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(12)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(12)(iii) of this section.

(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 pursuant to paragraph (b)(2)(i)(B), (b)(2)(ii)(B) or (C), or (b)(13)(i) of this section 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, 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 areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of §§ 97.526(c) and 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances between certain Allowance Management System accounts under common control);

(B) The provisions of §§ 97.526(d) and 97.826(d) and (e) of this chapter (concerning the conversion of unused CSAPR NO_X Ozone Season Group 1 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances and the conversion of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 3 allowances); and

(C) The provisions of § 97.811(d) and (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 specified control periods and recorded in specified Allowance Management System accounts).

(15) * * *

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(4) of this section as replacing the CSAPR NO_X Ozone Season Group 1 allowance allocation provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter 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 for the control period in 2017 or any subsequent year: [none].

* * * * *

(16) * * *

(i) * * *

(B) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(8) of this section as replacing the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter 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 for the control period in 2019 or any subsequent year: New York.

(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 sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for 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 allowance allocation provisions in § 97.1011(a)(1) of this chapter 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 for 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 subparts CCCCC and DDDDD, except";
■ b. In paragraph (d) introductory text, removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ c. In paragraph (d)(1), removing "State and" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";
■ d. In paragraph (e) introductory text, removing "for the State's sources, and" and adding in its place "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, and";
■ e. Revising table 1 to paragraph (e)(1)(ii);
■ f. In paragraph (e)(2), removing "deadlines for submission of allocations or auction results under paragraphs (e)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (e)(1)(ii)";
■ g. 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";
■ h. Revising table 2 to paragraph (f)(1)(ii);
■ i. 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";
■ j. 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";
■ k. In paragraph (f)(6), removing "deadlines for submission of allocations or auction results under paragraphs (f)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (f)(1)(ii)";
■ l. In paragraph (g) introductory text:
■ i. Removing "(c)(1) or (2)" and adding in its place "(c)"; and
■ ii. Removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ m. In paragraph (g)(1), removing "State and" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";
■ n. In paragraph (h) introductory text, removing "for the State's sources, and" and adding in its place "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, and";
■ o. Revising table 3 to paragraph (h)(1)(ii);
■ p. In paragraph (h)(2), removing "deadlines for submission of allocations or auction results under paragraphs (h)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (h)(1)(ii)";
■ q. 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";
■ r. Revising table 4 to paragraph (i)(1)(ii);
■ s. 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";
■ t. 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";
■ u. In paragraph (i)(6), removing "deadlines for submission of allocations or auction results under paragraphs (i)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (i)(1)(ii)";
■ v. Revising paragraphs (j) and (k)(2);
■ w. Adding paragraph (k)(3);
■ x. In paragraphs (l)(1) and (2), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ y. In paragraph (l)(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:".
■ z. In paragraphs (m)(1) and (2), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for"; and
■ aa. In paragraph (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 and addition 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(f) * * *

(1) * * *

(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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or 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
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or 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 subject to the State's SIP authority, 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.

(3) Notwithstanding any discontinuation pursuant to paragraph

(c)(2) or (j) of this section of the applicability of subpart CCCCC or DDDDD 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, the following provisions shall continue to apply with regard to all CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(i) The provisions of §§ 97.626(c) and 97.726(c) of this chapter (concerning the transfer of CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances between certain Allowance Management System accounts under common control).

(ii) [Reserved]

* * * * *

■ 4. Add §§ 52.40 through 52.46 to subpart A to read as follows:

Sec.

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§ 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) *Purpose.* 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) *Definitions.* The terms used in this section and §§ 52.41 through § 52.46 are defined as follows:

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Existing affected unit means any affected unit for which construction commenced before August 4, 2023.

New affected unit means any affected unit for which construction commenced on or after August 4, 2023.

Operator means any person who operates, controls, or supervises an affected unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such affected unit.

Owner means any holder of any portion of the legal or equitable title in an affected unit.

Potential to emit means the maximum capacity of a unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the unit to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a unit.

Rolling average means the weighted average of all data, meeting quality assurance and quality control (QA/QC) requirements in this part 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.

(c) *General requirements.* (1) The NO_X emissions limitations or emissions control requirements 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 reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing Industry, 52.44 for furnaces in the Glass and Glass Product Manufacturing Industry, 52.45 for boilers in the Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries, and 52.46 for Municipal Waste Combustors.

(2) The provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 apply to affected units 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, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

(3) The testing, monitoring, recordkeeping, and reporting requirements of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 only apply during the ozone season, except as otherwise specified in these sections. Additionally, if an owner or operator of an affected unit chooses to conduct a performance or compliance test outside of the ozone season, all recordkeeping, reporting, and notification requirements associated

with that test shall apply, without regard to whether they occur during the ozone season.

(d) *Requests for extension of compliance.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections by May 1, 2026, due to circumstances entirely beyond the owner or operator's control, may request an initial compliance extension to a date certain no later than May 1, 2027. The extension request must contain a demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(2) If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the extended compliance date due to circumstances entirely beyond the owner or operator's control, the owner or operator may apply for a second compliance extension to a date certain no later than May 1, 2029. The extension request must contain an updated demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(3) Each request for a compliance extension shall demonstrate that the owner or operator has taken all steps possible to install the controls necessary for compliance with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the applicable compliance date and shall:

(i) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46;

(iii) Identify the circumstances entirely beyond the owner or operator's control that necessitate additional time to install the identified controls;

(iv) Identify the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated;

(v) Identify the owner or operator's proposed compliance date. A request for an initial compliance extension under paragraph (d)(1) of this section must specify a proposed compliance date no later than May 1, 2027, and state whether the owner or operator anticipates a need to request a second compliance extension. A request for a second compliance extension under paragraph (d)(2) of this section must specify a proposed compliance date no later than May 1, 2029, and identify additional actions taken by the owner or operator to ensure that the affected unit(s) will be in compliance with the applicable requirements in this section by that proposed compliance date;

(vi) Include all information obtained from control technology vendors demonstrating that the identified controls cannot be installed by the applicable compliance date;

(vii) Include any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(viii) Include any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permitting authority identifying its anticipated timeframe for issuance of such permit(s).

(4) Each request for a compliance extension shall be submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) or analogous electronic submission system provided by the EPA no later than 180 days prior to the applicable compliance date. Until an extension has been granted by the Administrator under this section, the owner or operator of an affected unit shall comply with all applicable requirements of this section and shall remain subject to the May 1, 2026 compliance date or the initial extended compliance date, as applicable. A denial will be effective as of the date of denial.

(5) The owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(5) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the conditions of the extension of compliance. The conditions of a compliance extension granted under this paragraph (d)(5) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(6) Based on the information provided in any request made under paragraph (d) of this section or other information, the Administrator may grant an extension of time to comply with applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 consistent with the provisions of paragraph (d)(1) or (2) of this section. The decision to grant an extension will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will identify each affected unit covered by the extension; specify the termination date of the extension; and specify any additional conditions that the Administrator deems necessary to ensure timely installation of the necessary controls (*e.g.,* the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated).

(7) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(7) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(8) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to grant or intention to deny a request for a compliance extension within 60 calendar days after providing written notification pursuant to paragraph (d)(7) of this section that the submitted request is complete.

(9) Before denying any request for an extension of compliance, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(10) The Administrator's final decision to deny any request for an extension will be provided via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information

or argument (if the request is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(9)(ii) of this section, if no such submission is made.

(11) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the Clean Air Act (CAA or the Act).

(e) *Requests for case-by-case emissions limits.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections due to technical impossibility or extreme economic hardship may submit to the Administrator, by August 5, 2024, a request for approval of a case-by-case emissions limit. The request shall contain information sufficient for the Administrator to confirm that the affected unit is unable to comply with the applicable emissions limit, due to technical impossibility or extreme economic hardship, and to establish an appropriate alternative case-by-case emissions limit for the affected unit. Until a case-by-case emissions limit has been approved by the Administrator under this section, the owner or operator shall remain subject to all applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. A denial will be effective as of the date of denial.

(2) Each request for a case-by-case emissions limit shall include, but not be limited to, the following:

(i) A demonstration that the affected unit cannot achieve the applicable emissions limit with available control technology due to technical impossibility or extreme economic hardship.

(A) A demonstration of technical impossibility shall include:

(*1*) Uncontrolled NO_X emissions for the affected unit established with a CEMS, or stack tests obtained during steady state operation in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii)(2), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking; and

(*2*) A demonstration that the affected unit cannot meet the applicable emissions limit even with available control technology, including:

(*i*) Stack test data or other emissions data for the affected unit; or

(*ii*) A third-party engineering assessment demonstrating that the affected unit cannot meet the applicable emissions limit with available control technology.

(B) A demonstration of extreme economic hardship shall include at least three vendor estimates of the costs of installing control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of complying with the applicable emissions limit would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry.

(ii) An analysis of available control technology options and a proposed case-by-case emissions limit that represents the lowest emissions limitation technically achievable by the affected unit without causing extreme economic hardship relative to the costs borne by other comparable sources in the industry. The owner or operator may propose additional measures to reduce NO_X emissions, such as operational standards or work practice standards.

(iii) Calculations of the NO_X emissions reduction to be achieved through implementation of the proposed case-by-case emissions limit and any additional proposed measures, the difference between this NO_X emissions reduction level and the NO_X emissions reductions that would have occurred if the affected unit complied with the applicable emissions limitations in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, and a description of the methodology used for these calculations.

(3) The owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(3) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the case-by-case emissions limit. Any case-by-case emissions limit approved under this paragraph (e)(3) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(4) Based on the information provided in any request made under this paragraph (e)(4) or other information, the Administrator may approve a case-by-case emissions limit that will apply to an affected unit in lieu of the applicable emissions limit in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. The decision to approve a case-by-case emissions limit will be provided via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section and publicly available, and will identify each affected unit covered by the case-by-case emissions limit.

(5) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section to the owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(5) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(6) The Administrator will provide notification via the CEDRI or analogous electronic submission system described by the EPA in paragraph (d) of this section, which shall be publicly available, to the owner or operator of a decision to approve or intention to deny the request within 60 calendar days after providing notification pursuant to paragraph (e)(5) of this section that the submitted request is complete.

(7) Before denying any request for a case-by-case emissions limit, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(8) The Administrator's final decision to deny any request for a case-by-case emissions limit will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPAand publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the request is complete), or within 60 calendar days after the deadline for the

submission of additional information or argument under paragraph (e)(7)(ii) of this section, if no such submission is made.

(9) The approval of a case-by-case emissions limit under this section shall not abrogate the Administrator's authority under section 114 of the Act.

(f) *Recordkeeping requirements.* (1) The owner or operator of an affected unit subject to the provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 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 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.

(2) Any records required to be maintained by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 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.

(g) *CEDRI reporting requirements.* (1) You shall submit the results of the performance test following the procedures specified in paragraphs (g)(1)(i) through (iii) of this section:

(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 § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, 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)(A) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (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) or (2) of this section, you should submit a complete file, including information claimed to be CBI, to the EPA.

(B) 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.

(C) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(D) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address *oaqpscbi@epa.gov*, and as described in this paragraph (g), should include clear CBI markings and be flagged to the attention of Lead of 2015 Ozone Transport FIP. 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.

(E) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Lead of 2015 Ozone Transport FIP. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(F) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. 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.

(G) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in paragraphs (g)(1) and (2) of this section.

(2) Annual reports must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46.

(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 (g)(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 (g)(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 unit, its contractors, or any entity controlled by the affected unit 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 unit (*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.

§ 52.41 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 in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an engine meeting the applicability criteria of this section.

Cap means the total amount of NO_X emissions, in tons per day on a 30-day rolling average basis, that is collectively allowed from all of the affected units covered by a Facility-Wide Averaging Plan and is calculated as the sum each affected unit's NO_X emissions at the emissions limit applicable to such unit under paragraph (c) of this section, converted to tons per day in accordance with paragraph (d)(3) of this section.

Emergency engine means any stationary reciprocating internal combustion engine (RICE) that meets all of the criteria in paragraphs (i) and (ii) of this definition. All emergency stationary RICE must comply with the requirements specified in paragraph (b)(1) of this section in order to be considered emergency engines. If the engine does not comply with the requirements specified in paragraph (b)(1), it is not considered an emergency engine under this section.

(i) The stationary engine is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(ii) The stationary RICE is operated under limited circumstances for purposes other than those identified in paragraph (i) of this definition, as specified in paragraph (b)(1) of this section.

Facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same first two digit code as described in the Standard Industrial Classification Manual, 1987). For purposes of this section, a facility may not extend beyond the 20 states identified in § 52.40(b)(2).

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.

Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, but not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are within a single state that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems. LDCs do not include pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

Local Distribution Company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Nameplate rating means the manufacturer's maximum design 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.

Natural gas processing plant means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas production facility means all equipment at a single stationary source directly associated with one or more natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the engine.

Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, including the compressor and pipeline network used to transport the natural gas from processing plants over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and prior to delivery to a "local distribution company custody transfer station" (as defined in this section) of an LDC that provides the natural gas to end-users. *Pipeline transportation of natural gas* does not include natural gas production facilities, natural gas processing plants, or the portion of a compressor and pipeline network that is upstream of a natural gas processing plant.

Reciprocating internal combustion engine (RICE) 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 emissions control technology for nitrogen oxides (NO_X) (such as pre-combustion chambers) will be considered lean burn engines. Existing affected unit 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, other than an emergency 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(c)(2), including Indian country located within the borders of any such State(s).

(1) For purposes of this section, the owner or operator of an emergency stationary RICE must operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii) of this section to be treated as an emergency stationary RICE. In order for stationary RICE to be treated as an emergency RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for up to 50 hours per year, as described in paragraphs (b)(1)(i) through (iii), is prohibited. If you do not operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii), the RICE will not be considered an emergency engine under this section and must meet all requirements for affected units in this section.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The owner or operator may operate your emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by a Federal, state, or local government agency, the manufacturer, the vendor, or the insurance company associated with the engine. Any operation for non-emergency situations as allowed by paragraph (b)(1)(iii) of this section counts as part of the 100 hours per calendar year allowed by paragraph (b)(1)(ii) of this section. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records confirming that Federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any approval of a petition for additional hours granted by the Administrator under 40 CFR part 63, subpart ZZZZ, shall constitute approval by the Administrator of the same petition under this paragraph (b)(1)(ii).

(iii) Emergency stationary RICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (b)(1)(ii) of this section.

(2) If you own or operate a natural gas-fired two stroke lean burn spark ignition engine manufactured after July 1, 2007 that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(3) If you own or operate a natural gas-fired four stroke lean or rich burn spark ignition engine manufactured after July 1, 2010, that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Natural gas-fired four stroke rich burn spark ignition engine: 1.0 grams per hp-hour (g/hp-hr);

(2) Natural gas-fired four stroke lean burn spark ignition engine: 1.5 g/hp-hr; and

(3) Natural gas-fired two stroke lean burn spark ignition engine: 3.0 g/hp-hr.

(d) *Facility-Wide Averaging Plan.* If you are the owner or operator of a facility containing more than one affected unit, you may submit a request via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator for approval of a proposed Facility-Wide Averaging Plan as an alternative means of compliance with the applicable emissions limits in paragraph (c) of this section. Any such request shall be submitted to the Administrator on or before October 1st of the year prior to each emissions averaging year. The Administrator will approve a proposed Facility-Wide Averaging Plan submitted under this paragraph (d) if the Administrator determines that the proposed Facility-Wide Averaging Plan meets the requirements of this paragraph (d), will provide total emissions reductions equivalent to or greater than those achieved by the applicable emissions limits in paragraph (c), and identifies satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, recordkeeping, and reporting requirements. You may only include affected units (*i.e.,* engines meeting the applicability criteria in paragraph (b) of this section) in a Facility-Wide Averaging Plan. Upon EPA approval of a proposed Facility-Wide Averaging Plan, you cannot withdraw any affected unit listed in such plan, and the terms of the plan may not be changed unless approved in writing by the Administrator.

(1) Each request for approval of a proposed Facility-Wide Averaging Plan shall include, but not be limited to:

(i) The address of the facility;

(ii) A list of all affected units at the facility that will be covered by the plan, identified by unit identification number, the engine manufacturer's name, and model;

(iii) For each affected unit, a description of any existing NO_X emissions control technology and the date of installation, and a description of any NO_X emissions control technology to be installed and the projected date of installation;

(iv) Identification of the emissions cap, calculated in accordance with paragraph (d)(3) of this section, that all affected units covered by the proposed Facility-Wide Averaging Plan will be subject to during the ozone season, together with all assumptions included in such calculation; and

(iv) Adequate provisions for testing, monitoring, recordkeeping, and reporting for each affected unit.

(2) Upon the Administrator's approval of a proposed Facility-Wide Averaging Plan, the owner or operator of the affected units covered by the Facility-Wide Averaging Plan shall comply with the cap identified in the plan in lieu of the emissions limits in paragraph (c) of this section. You will be in compliance with the cap if the sum of NO_X emissions from all units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, is less than or equal to the cap.

(3) The owner or operator will calculate the cap according to equation 1 to this paragraph (d)(3). You will monitor and record daily hours of engine operation for use in calculating the cap on a 30-day rolling average basis. You will base the hours of operation on hour readings from a non-resettable hour meter or an equivalent monitoring device.

Equation 1 to Paragraph (d)(3)

$$Cap\ (tons\ per\ day) = 907{,}184.74\ x \sum_{i=1}^{N} (R_{li}\ x\ DC\ x\ H_i)$$

Where:

H_i = the average daily operating hours based on the highest consecutive 30-day period during the ozone season of the two most recent years preceding the emissions averaging year (hours).

i = each affected unit included in the Cap.

N = number of affected units.

DC = the engine manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions.

R_{li} = the emissions limit for each affected unit from paragraph (c) of this section (grams/hp-hr).

(i) Any affected unit for which less than two years of operating data are available shall not be included in the Facility-Wide Averaging Plan unless the owner or operator extrapolates the available operating data for the affected unit to two years of operating data, for use in calculating the emissions cap in accordance with paragraph (d)(3) of this section.

(ii) [Reserved]

(4) The owner or operator of an affected units covered by an EPA-approved Facility-Wide Averaging Plan will be in violation of the cap if the sum of NO_X emissions from all such units, in tons per day on a 30-day rolling average basis, exceeds the cap. Each day of noncompliance by each affected unit covered by the Facility-Wide Averaging Plan shall be a violation of the cap until corrective action is taken to achieve compliance.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit subject to a NO_X emissions limit under paragraph (c) 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) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) 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).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions 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.

(3)(i) If you are the owner or operator of a new affected unit, you must conduct an initial performance test within six months of engine startup and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(ii) If you are the owner or operator of an existing affected unit, you must conduct an initial performance test within six months of becoming subject to an emissions limit under paragraph (c) of this section and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(iii) If you are the owner or operator of a new or existing affected unit that is only operated during peak demand periods outside of the ozone season and the engine's hours of operation during the ozone season are 50 hours or less, the affected unit is not subject to the testing and monitoring requirements of this paragraph (e)(3)(iii) as long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(iv) If you are the owner or operator of an affected unit, you must conduct all performance tests consistent with the requirements of 40 CFR 60.4244 in accordance with the applicable reference test methods identified in table 2 to subpart JJJJ of 40 CFR part 60, any alternative test method approved by the EPA as of June 5, 2023, 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 the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. To determine compliance with the NO_X emissions limit in paragraph (c) of this section, the emissions rate shall be calculated in accordance with the requirements of 40 CFR 60.4244(d).

(4) If you are the owner or operator of an affected unit that has a non-selective catalytic reduction (NSCR) control device to reduce emissions, you must:

(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; and

(ii) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop across the catalyst changes by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the most recent performance test.

(5) If you are the owner of operator of an affected unit not using an NSCR control device to reduce emissions, you are required to conduct continuous parametric monitoring to assure compliance with the applicable emissions limits according to the requirements in paragraphs (e)(5)(i) through (vi) of this section.

(i) You must prepare a site-specific monitoring plan that includes all of the following monitoring system design, data collection, and quality assurance and quality control elements:

(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 (e)(1) of this section.

(E) Ongoing recordkeeping and reporting procedures in accordance with the requirements of paragraphs (f) and (g) of this section.

(ii) You must continuously monitor the selected operating parameters according to the procedures in your site-specific monitoring plan.

(iii) You must collect parametric monitoring data at least once every 15 minutes.

(iv) When 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 performance evaluations, 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 parametric monitoring device in accordance with your site-specific monitoring plan.

(6) If you are the owner or operator of an affected unit that is only operated during peak periods outside of the ozone season and your hours of operation during the ozone season are 0, you are not subject to the testing and monitoring requirements of this paragraph (e)(6) so long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you must keep records of:

(1) Performance tests conducted pursuant to paragraph (e)(2) of this section, including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

(2) Catalyst monitoring required by paragraph (e)(3) of this section, 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.

(3) Parameters monitored pursuant to the facility's site-specific parametric monitoring plan.

(4) Hours of operation on a daily basis.

(5) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).

(6) For any Facility-Wide Averaging Plan approved by the Administrator under paragraph (d) of this section, daily calculations of total NO_X emissions to demonstrate compliance with the cap during the ozone season. You must use the equation in this paragraph (f)(6) to calculate total NO_X emissions from all affected units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, for purposes of determining compliance with the cap during the ozone season. A new 30-day rolling average emissions rate in tpd is calculated for each operating day during the ozone season, using the 30-day rolling average daily operating hours for the preceding 30 operating days.

Equation 2 to Paragraph (f)(6)

$$\sum_{i=1}^{N}(R_{ai}\ x\ DC\ x\ H_{ai}) \leq Cap\ (tons\ per\ day)$$

Where:

H_{ai} = the consecutive 30-day rolling average daily operating hours for the preceding 30 operating days during ozone season (hours).
i = each affected unit.
N = number of affected units.
DC = the engine manufacturer's maximum design capacity in horsepower (hp) at the installation site conditions.
R_{ai} = the actual emissions rate for each affected unit based on the most recent performance test results, (grams/hp-hr).

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions 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 following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you must submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in paragraph (g) of 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 emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section;

(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 paragraph (e) of this section;

(viii) Any records required by paragraph (f) of this section, including records of parametric monitoring data, to demonstrate compliance with the applicable emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section, if applicable;

(ix) If applicable, a statement documenting any change in the operating characteristics of the subject engine; and

(x) A statement certifying that the information included in the annual report is complete and accurate.

§ 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 in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a cement kiln meeting the applicability criteria of this section.

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.

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.

Operating day means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time.

(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 on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing cement kiln with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Long wet kilns: 4.0 lb/ton of clinker;

(2) Long dry kilns: 3.0 lb/ton of clinker;

(3) Preheater kilns: 3.8 lb/ton of clinker;

(4) Precalciner kilns: 2.3 lb/ton of clinker; and

(5) Preheater/Precalciner kilns: 2.8 lb/ton of clinker.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, 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 the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. You must calculate and record the 30-operating day rolling average emissions 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 1 to this paragraph (d)(1):

Equation 1 to Paragraph (d)(1)

$$E_{30D} = k\left(\frac{\sum_{i=1}^{N} Ci\ Qi}{P}\right)$$

Where:

E_{30D} = 30 kiln operating day average emissions 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, $1.194 \times ^{10-7}$ for NO_X, in lb/scf/ppm.

n = Number of kiln operating hours over 30 kiln operating days.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) 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).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of clinker and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions 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.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (d)(3)(i) through (v) of this section.

(i) You must monitor and record kiln stack exhaust gas flow rate, hourly clinker production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must determine hourly clinker production by one of two methods:

(A) Install, calibrate, maintain, and operate a permanent weigh scale system to record weight rates of the amount of clinker produced in tons of mass per hour. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy; or

(B) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production rates determined for accounting purposes and recorded feed rates. This ratio should be updated monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(C) For each kiln operating hour for which you do not have data on clinker production or the amount of feed to the kiln, use the value from the most recent previous hour for which valid data are available.

(D) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the daily kiln feed and clinker production rates.

(iii) You must use the kiln stack exhaust gas flow rate, hourly kiln production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests as indicators of NO_X operating parameters to demonstrate continuous compliance and establish site-specific indicator ranges for these operating parameters.

(iv) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(v) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (e) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(e) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) 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;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) 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 to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season;

(9) Each fuel type, usage, and heat content; and

(10) Clinker production rates.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraph (c) of this section. Excess emissions 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 following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (d) of this section, including record of CEMS data or operating parameters required by paragraph (d) to demonstrate continuous compliance the applicable emissions limits under paragraph (c) of this section.

(g) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (g) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 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 in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means any reheat furnace meeting the applicability criteria of this section.

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.

Low NO_X burner means a burner designed to reduce flame turbulence by the mixing of fuel and air and by establishing fuel-rich zones for initial combustion, thereby reducing the formation of NO_X.

Low-NO_X technology means any post-combustion NO_X control technology capable of reducing NO_X emissions by 40% from baseline emission levels as measured during pre-installation testing.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the reheat furnace.

Reheat furnace means a furnace used to heat steel product—including metal ingots, billets, slabs, beams, blooms and other similar products—for the purpose of deformation and rolling.

(b) *Applicability.* The requirements of this section apply to each new or existing reheat furnace 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 on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing reheat furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions control requirements.* If you are the owner or operator of an affected unit without low-NO_X burners already installed, you must install and operate low-NO_X burners or equivalent alternative low-NO_X technology designed to achieve at least a 40% reduction from baseline NO_X emissions in accordance with the work plan established pursuant to paragraph (d) of this section. You must meet the emissions limit established under paragraph (d) on a 30-day rolling average basis.

(d) *Work plan requirements.* (1) The owner or operator of each affected unit must submit a work plan for each affected unit by August 5, 2024. The work plan must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g). Each work plan must include a description of the affected unit and rated production and energy capacities, identification of the low-NO_X burner or alternative low NO_X technology selected, and the phased construction timeframe by which you will design, install, and consistently operate the device. Each work plan shall also include, where applicable, performance test results obtained no more than five years before August 4, 2023, to be used as baseline emissions testing data providing the basis for required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing as described in paragraph (e)(3) of this section.

(2) The owner or operator of an affected unit shall design each low-NO_X burner or alternative low-NO_X technology identified in the work plan to achieve NO_X emission reductions by a minimum of 40% from baseline emission levels measured during performance testing that meets the criteria set forth in paragraph (e)(1) of this section, or during pre-installation testing as described in paragraph (e)(3) of this section. Each low-NO_X burner or alternative low-NO_X technology shall be continuously operated during all production periods according to paragraph (c) of this section.

(3) The owner or operator of an affected unit shall establish an emissions limit in the work plan that the affected unit must comply with in accordance with paragraph (c) of this section.

(4) The EPA's action on work plans:

(i) The Administrator will provide via the CEDRI or analogous electronic submission system provided by the EPA notification to the owner or operator of an affected unit if the submitted work plan is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original work plan and within 60 calendar days after receipt of any supplementary information.

(ii) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to approve or intention to disapprove the work plan within 60 calendar days after providing written notification pursuant to paragraph (d)(4)(i) of this section that the submitted work plan is complete.

(iii) Before disapproving a work plan, the Administrator will notify the owner or operator via the CEDRI or analogous electronic submission system provided by the EPA of the Administrator's intention to issue the disapproval, together with:

(A) Notice of the information and findings on which the intended disapproval is based; and

(B) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended disapproval, additional information or arguments to the Administrator before further action on the work plan.

(iv) The Administrator's final decision to disapprove a work plan will be via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the disapproval is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the submitted work plan is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(5)(iii)(B) of this section, if no such submission is made.

(v) If the Administrator disapproves the submitted work plan for failure to satisfy the requirements of paragraphs (c) and (d)(1) through (3) of this section, or if the owner or operator of an affected unit fails to submit a work plan by August 5, 2024, the owner or operator will be in violation of this section. Each day that the affected unit operates following such disapproval or failure to submit shall constitute a violation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, 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 the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) 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).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in form of the emissions limit established in the work plan and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits established in the work plan.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions 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.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (e)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to establish a site-specific indicator for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (f) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) 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;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) 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 to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season; and

(9) Each fuel type, usage, and heat content.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit a final report via the CEDRI or analogous electronic submission system provided by the EPA, by no later than March 30, 2026, certifying that installation of each selected control device has been completed. You shall include in the report the dates of final construction and relevant performance testing, where applicable, demonstrating compliance with the selected emission limits pursuant to paragraphs (c) and (d) of this section.

(2) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(3) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraphs (c) and (d) of this section. Excess emissions 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 following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraphs (e) and (f) of this section, including record of CEMS data or operating parameters required by paragraph (e) to demonstrate compliance the applicable emissions limits established under paragraphs (c) and (d) of this section.

(h) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (h) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or more of NO_X as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 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 in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected units means a glass manufacturing furnace meeting the applicability criteria of this section.

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 (SIC) 3221 (SIC 3221).

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.

Idling means the operation of a glass melting furnace at less than 25% of the permitted production capacity or fuel use capacity as stated in the operating permit.

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.

Operating day means a 24-hr period beginning at 12:00 midnight during which the furnace combusts fuel at any time but excludes any period of startup, shutdown, or idling during which the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

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.

Shutdown means the period of time during which a glass melting furnace is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to a cold or ambient temperature as the fuel supply is turned off.

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.

Startup means the period of time, after initial construction or a furnace rebuild, during which a glass melting furnace is heated to operating temperatures by the primary furnace combustion system, and systems and instrumentation are brought to stabilization.

Textile fiberglass means fibrous glass in the form of continuous strands having uniform thickness.

Wool fiberglass means fibrous glass of random texture, including accoustical board and tile (mineral wool), fiberglass insulation, glass wool, insulation (rock wool, fiberglass, slag, and silicia minerals), and mineral wool roofing mats.

(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 on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing glass manufacturing furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the emissions limitations in paragraphs (c)(1) and (2) of this section on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter. For the 2026 ozone season, the emissions limitations in paragraphs (c)(1) and (2) do not apply during shutdown and idling if the affected unit complies with the requirements in paragraphs (e) and (f) of this section, as applicable. For the 2027 and subsequent ozone seasons, the emissions limitations in paragraphs (c)(1) and (2) do not apply during startup, shutdown, and idling, if the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

(1) Container glass, pressed/blown glass, or fiberglass manufacturing furnace: 4.0 lb/ton of glass; and

(2) Flat glass manufacturing furnace: 7.0 lb/ton of glass.

(d) *Startup requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA, no later than 30 days prior to the anticipated date of startup, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during startup and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the startup period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during startup periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The length of startup following activation of the primary furnace combustion system may not exceed:

(i) Seventy days for a container, pressed or blown glass furnace;

(ii) Forty days for a fiberglass furnace; and

(iii) One hundred and four days for a flat glass furnace and for all other glass melting furnaces not covered under paragraphs (d)(2)(i) and (ii) of this section.

(3) During the startup period, the owner or operator of an affected unit shall maintain the stoichiometric ratio of the primary furnace combustion system so as not to exceed 5 percent excess oxygen, as calculated from the actual fuel and oxidant flow measurements for combustion in the affected unit.

(4) The owner or operator of an affected unit shall place the emissions control system in operation as soon as technologically feasible during startup to minimize emissions.

(e) *Shutdown requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator, no later than 30 days prior to the anticipated date of shutdown, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during shutdown and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the shutdown period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during shutdown periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The duration of a shutdown, as measured from the time the furnace operations drop below 25% of the permitted production capacity or fuel use capacity to when all emissions from the furnace cease, may not exceed 20 days.

(3) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during shutdown to minimize emissions.

(f) *Idling requirements.* (1) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during idling to minimize emissions.

(2) If you are the owner or operator of an affected unit, your NO_X emissions during idling may not exceed the amount calculated using the following equation: Pounds per day emissions limit of NO_X = (Applicable NO_X emissions limit specified in paragraph (c) of this section expressed in pounds per ton of glass produced) × (Furnace permitted production capacity in tons of glass produced per day).

(3) To demonstrate compliance with the alternative daily NO_X emissions limit identified in paragraph (f)(2) of this section during periods of idling, the owners or operators of an affected unit shall maintain records consistent with paragraph (h)(3) of this section.

(g) *Testing and monitoring requirements.* (1) If you own or operate an affected unit subject to the NO_X emissions limits under paragraph (c) of this section you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, 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 the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. Owners or operators of affected units must calculate and record the 30-day rolling average emissions rate of NO_X as the total of all hourly emissions data for an affected unit in the preceding 30 days, divided by the total tons of glass produced in that affected unit during the same 30-day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass produced during the performance test.

The rate of glass produced is defined as the weight of glass pulled from the affected unit during the performance test divided by the number of hours taken to perform the performance test.

(2) If you are the owner or operator of an affected unit subject to the NO_X emissions limits under paragraph (c)(1) of this section and are operating a NO_X CEMS that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) 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).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of glass and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions 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.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (g)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests as NO_X CEMS indicators to demonstrate continuous compliance and establish a site-specific indicator ranges for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (h) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(4) If you are the owner or operator of an affected unit seeking to comply with the requirements for startup under paragraph (d) of this section or shutdown under paragraph (e) of this section in lieu of the applicable emissions limit under paragraph (c) of this section, you must monitor material process flow rates, fuel throughput, oxidant flow rate, and the selected system operating parameters in accordance with paragraphs (d)(1)(ii) and (e)(1)(ii) of this section.

(h) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit 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 emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(vii) If a CEMS is used to verify compliance:

(A) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(B) 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 to 40 CFR part 60; and

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(D) Operating parameters required under paragraph (g) to demonstrate compliance during the ozone season;

(viii) Each fuel type, usage, and heat content; and

(ix) Glass production rate.

(2) If you are the owner or operator of an affected unit, you shall maintain all records necessary to demonstrate compliance with the startup and shutdown requirements in paragraphs (d) and (e) of this section, including but not limited to records of material process flow rates, system operating parameters, the duration of each startup and shutdown period, fuel throughput, oxidant flow rate, and any additional records necessary to determine whether the stoichiometric ratio of the primary furnace combustion system exceeded 5 percent excess oxygen during startup.

(3) If you are the owner or operator of an affected unit, you shall maintain records of daily NO_X emissions in pounds per day for purposes of determining compliance with the applicable emissions limit for idling periods under paragraph (f)(2) of this section. Each owner or operator shall also record the duration of each idling period.

(i) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions 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 following the procedures specified in § 52.40(g).

(3) If you own or operate an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (g) of this section, including record of CEMS data or operating parameters to demonstrate continuous compliance the applicable emissions limits under paragraphs (c) of this section.

(j) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (j) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit greater than 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than June 23, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 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, the Pulp, Paper, and Paperboard Mills Industries, Metal Ore Mining, and the Iron and Steel and Ferroalloy Manufacturing Industries?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to 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.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled.

Coal means ''coal'' as defined in 40 CFR 60.41b.

Distillate oil means ''distillate oil'' as defined in 40 CFR 60.41b.

Maximum heat input capacity means means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means ''natural gas'' as defined in 40 CFR 60.41.

Operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Residual oil means ''residual oil'' as defined in 40 CFR 60.41c.

(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 that receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels in the previous ozone season, is located at sources that are within the Basic Chemical Manufacturing industry, the Petroleum and Coal Products Manufacturing industry, the Pulp, Paper, and Paperboard industry, the Metal Ore Mining industry, and the Iron and Steel and Ferroalloys Manufacturing industry and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). The requirements of this section do not apply to an emissions unit that meets the requirements for a low-use exemption as provided in paragraph (b)(2) of this section.

(2) If you are the owner or operator of a boiler meeting the applicability criteria of paragraph (b)(1) of this section that operates less than 10% per year on an hourly basis, based on the three most recent years of use and no more than 20% in any one of the three years, you are exempt from meeting the emissions limits of this section and are only subject to the recordkeeping and reporting requirements of paragraph (f)(2) of this section.

(i) If you are the owner or operator of an affected unit that exceeds the 10% per year hour of operation over three years or the 20% hours of operation per year criteria, you can no longer comply via the low-use exemption provisions and must meet the applicable emissions limits and other applicable provisions as soon as possible but not later than one year from the date eligibility as a low-use boiler was negated by exceedance of the low-use boiler criteria.

(ii) [Reserved]

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Coal-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(2) Residual oil-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO_X/mmBtu;

(4) Natural gas-fired industrial boilers: 0.08 lbs NO_X/mmBtu; and

(5) Boilers using combinations of fuels listed in paragraphs (c)(1) through (4) of this section: such units shall comply with a NO_X emissions limit derived by summing the products of each fuel's heat input and respective emissions limit and dividing by the sum of the heat input contributed by each fuel.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, 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 of 40 CFR part 60, appendix A–4, to determine compliance with the emissions limits for NO_X identified in paragraph (c) of this section. In lieu of the timing of the compliance test described in 40 CFR 60.8(a), you shall conduct the test within 90 days from the installation of the pollution control equipment used to comply with the NO_X emissions limits in paragraph (c) of this section and no later than May 1, 2026.

(i) For the initial compliance test, you shall monitor NO_X emissions from the affected unit for 30 successive operating days and the 30-day average emissions rate will be used to determine compliance with the NO_X emissions limits in paragraph (c) of this section. You shall calculate the 30-day average emission rate as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(ii) You are not required to conduct an initial compliance test if the affected unit is subject to a pre-existing, federally enforceable requirement to monitor its NO_X emissions using a

CEMS in accordance with 40 CFR 60.13 or 40 CFR part 75.

(2) If you are the owner or operator of an affected unit with a heat input capacity of 250 mmBTU/hr or greater, you are subject to the following monitoring requirements:

(i) 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 you to use an alternative monitoring technique under paragraph (d)(2)(vii) of this section. If you have previously installed a NO_X emissions rate CEMS to meet the requirements of 40 CFR 60.13 or 40 CFR part 75 and continue to meet the ongoing requirements of 40 CFR 60.13 or 40 CFR part 75, that CEMS may be used to meet the monitoring requirements of this section.

(ii) You shall operate the CEMS and record data during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. You shall record data during calibration checks and zero and span adjustments.

(iii) You shall express the 1-hour average NO_X emissions rates measured by the CEMS in terms of lbs/mmBtu heat input and shall be used to calculate the average emissions rates under paragraph (c) of this section.

(iv) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO_X emissions limit in paragraph (c) of this section during the ozone season on a continuous basis using a 30-day rolling average emissions rate unless you monitor emissions by means of an alternative monitoring procedure approved pursuant to paragraph (d)(2)(vii) of this section. You shall calculate a new 30-day rolling average emissions rate for each operating day as the average of all the hourly NO_X emissions data for the preceding 30 operating days.

(v) You shall follow the procedures under 40 CFR 60.13 for installation, evaluation, and operation of the continuous monitoring systems. Additionally, you shall use a span value of 1000 ppm NO_X for affected units combusting coal and span value of 500 ppm NO_X for units combusting oil or gas. As an alternative to meeting these span values, 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.

(vi) When you are unable to obtain NO_X emissions data because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, you will obtain emissions data by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions 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.

(vii) You may delay installing a CEMS for NO_X 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 emissions limit in paragraph (c) of this section, you are not required to install a CEMS for measuring NO_X. If you demonstrate your affected unit emits less than 70 percent of the applicable emissions 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 emissions limit(s) in paragraph (c) of this section. The Administrator may 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.

(3) If you are the owner or operator of an affected unit with a heat input capacity less than 250 mmBTU/hr, you must monitor NO_X emission via the requirements of paragraph (e)(1) of this section or you must monitor NO_X emissions by conducting an annual test in conjunction with the implementation of a monitoring plan meeting the following requirements:

(i) You must conduct an initial performance test over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods.

(ii) You must conduct annual performance tests once per calendar year to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods. The annual performance test must be conducted before the affected units operates more than 400 hours in a given year.

(iii) You must develop and comply with a monitoring plan that relates the operational parameters to emissions of the affected unit. The owner or operator of each affected unit shall develop a monitoring plan that identifies the operating conditions of the affected unit to be monitored and the records to be maintained in order to reliably predict NO_X emissions and determine compliance with the applicable emissions limits of this section on a continuous basis. You shall include the following information in the plan:

(A) You shall identify the specific operating parameters to be monitored and the relationship between these operating parameters and the applicable NO_X emission rates. Operating parameters of the affected unit include, but are not limited to, the degree of staged combustion (*i.e.,* the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.,* flue gas O_2 level).

(B) You shall include the data and information used to identify the relationship between NO_X emission rates and these operating conditions.

(C) *You shall identify:* how these operating parameters, including steam generating unit load, will be monitored on an hourly basis during periods of operation of the affected unit; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating parameters will be representative and accurate; and the type and format of the records of these operating parameters, including steam generating unit load, that you will maintain.

(4) You shall submit the monitoring plan to the EPA via the CEDRI reporting system, and request that the relevant permitting agency incorporate the monitoring plan into the facility's title V permit.

(e) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, which is not a low-use boiler, you shall maintain records of the following information for each day the affected unit operates during the ozone season:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates (expressed as lbs NO_2/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day rolling average NO_X emissions rates are in excess of the applicable NO_X emissions 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 emissions data have been excluded from the calculation of average emissions 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 to 40 CFR part 60;

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F; and

(xi) The type and amounts of each fuel combusted.

(2) If you are the owner or operator of an affected unit complying as a low-use boiler, you must maintain the following records consistent with the requirements of § 52.40(g):

(i) Identification and location of the boiler;

(ii) Nameplate capacity;

(iii) The fuel or fuels used by the boiler;

(iv) For each operating day, the type and amount of fuel combusted, and the date and total number of hours of operation; and

(v) the annual hours of operation for each of the prior 3 years, and the 3-year average hours or operation.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate, as determined under paragraph (e)(1)(iii) of this section, that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions 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 following the procedures specified in § 52.40(g).

(3) If you are the owner or operator 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) of this section as described in paragraph (e)(1) of this section. You shall submit compliance reports for continuous monitoring in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g).

§ 52.46 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from Municipal Waste Combustors?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a municipal waste combustor meeting the applicability criteria of this section.

Chief facility operator means the person in direct charge and control of the operation of a municipal waste combustor and who is responsible for daily onsite supervision, technical direction, management, and overall performance of the facility.

Mass burn refractory municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a refractory wall furnace. Unless otherwise specified, this includes combustors with a cylindrical rotary refractory wall furnace.

Mass burn rotary waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a cylindrical rotary waterwall furnace or on a tumbling-tile grate.

Mass burn waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a waterwall furnace.

Municipal waste combustor, MWC, or *municipal waste combustor unit* means:

(i) Means any setting or equipment that combusts solid, liquid, or gasified MSW including, but not limited to, field-erected incinerators (with or without heat recovery), modular incinerators (starved-air or excess-air), boilers (*i.e.,* steam-generating units), furnaces (whether suspension-fired, grate-fired, mass-fired, air curtain incinerators, or fluidized bed-fired), and pyrolysis/combustion units. Municipal waste combustors do not include pyrolysis/combustion units located at plastics/rubber recycling units. Municipal waste combustors do not include internal combustion engines, gas turbines, or other combustion devices that combust landfill gases collected by landfill gas collection systems.

(ii) The boundaries of a MWC are defined as follows. The MWC unit includes, but is not limited to, the MSW fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The MWC boundary starts at the MSW pit or hopper and extends through:

(A) The combustor flue gas system, which ends immediately following the heat recovery equipment or, if there is no heat recovery equipment, immediately following the combustion chamber;

(B) The combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system; and

(C) The combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater.

(iii) The MWC unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine generator set.

Municipal waste combustor unit capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under paragraph (e)(4) of this section.

Shift supervisor means the person who is in direct charge and control of the operation of a municipal waste combustor and who is responsible for onsite supervision, technical direction, management, and overall performance of the facility during an assigned shift.

(b) *Applicability.* The requirements of this section apply to each new or existing municipal waste combustor unit with a combustion capacity greater than 250 tons per day (225 megagrams per day) of municipal solid waste and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations at all times, except during startup and shutdown, on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) 110 ppmvd at 7 percent oxygen on a 24-hour block averaging period; and

(2) 105 ppmvd at 7 percent oxygen on a 30-day rolling averaging period.

(d) *Startup and shutdown requirements.* If you are the owner or operator of an affected unit, you must comply with the following requirements during startup and shutdown:

(1) During periods of startup and shutdown, you shall meet the following emissions limits at stack oxygen content:

(i) 110 ppmvd at stack oxygen content on a 24-hour block averaging period; and

(ii) 105 ppmvd at stack oxygen content on a 30-day rolling averaging period.

(2) Duration of startup and shutdown, periods are limited to 3 hours per occurrence.

(3) The startup period commences when the affected unit begins the continuous burning of municipal solid waste and does not include any warmup period when the affected unit is combusting fossil fuel or other nonmunicipal solid waste fuel, and no municipal solid waste is being fed to the combustor.

(4) Continuous burning is the continuous, semicontinuous, or batch feeding of municipal solid waste for purposes of waste disposal, energy production, or providing heat to the combustion system in preparation for waste disposal or energy production. The use of municipal solid waste solely to provide thermal protection of the grate or hearth during the startup period when municipal solid waste is not being fed to the grate is not considered to be continuous burning.

(5) The owner and operator of an affected unit shall minimize NO_X emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)) for such equipment and the unit at all times the unit is in operation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, you shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring the oxygen or carbon dioxide content of the flue gas at each location where NO_X are monitored and record the output of the system. You shall comply with the following test procedures and test methods:

(i) You shall use a span value of 25 percent oxygen for the oxygen monitor or 20 percent carbon dioxide for the carbon dioxide monitor;

(ii) You shall install, evaluate, and operate the CEMS in accordance with 40 CFR 60.13;

(iii) You shall complete the initial performance evaluation no later than 180 days after the date of initial startup of the affected unit, as specified under 40 CFR 60.8;

(iv) You shall operate the monitor in conformance with Performance Specification 3 in 40 CFR part 60, appendix B, except for section 2.3 (relative accuracy requirement);

(v) You shall operate the monitor in accordance with the quality assurance procedures of 40 CFR part 60, appendix F, except for section 5.1.1 (relative accuracy test audit); and

(vi) If you select carbon dioxide for use in diluent corrections, you shall establish the relationship between oxygen and carbon dioxide levels during the initial performance test according to the following procedures and methods:

(A) This relationship may be reestablished during performance compliance tests; and

(B) You shall submit the relationship between carbon dioxide and oxygen concentrations to the EPA as part of the initial performance test report and as part of the annual test report if the relationship is reestablished during the annual performance test.

(2) If you are the owner or operator of an affected unit, you shall use the following procedures and test methods to determine compliance with the NO_X emission limits in paragraph (c) of this section:

(i) If you are not already operating a CEMS in accordance with 40 CFR 60.13, you shall conduct an initial performance test for nitrogen oxides consistent with 40 CFR 60.8.

(ii) You shall install and operate the NO_X CEMS according to Performance Specification 2 in 40 CFR part 60, appendix B, and shall follow the requirements of 40 CFR 60.58b(h)(10).

(iii) Quarterly accuracy determinations and daily calibration drift tests for the CEMS shall be performed in accordance with Procedure 1 in 40 CFR part 60, appendix F.

(iv) When NO_X continuous emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained using other monitoring systems as approved by the EPA or EPA Reference Method 19 in 40 CFR part 60, appendix A–7, to provide, as necessary, valid emissions data for a minimum of 90 percent of the hours per calendar quarter and 95 percent of the hours per calendar year the unit is operated and combusting municipal solid waste.

(v) You shall use EPA Reference Method 19, section 4.1, in 40 CFR part 60, appendix A–7, for determining the daily arithmetic average NO_X emissions concentration.

(A) You may request that compliance with the NO_X emissions limit be determined using carbon dioxide measurements corrected to an equivalent of 7 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected unit shall be established as specified in paragraph (e)(1)(vi) of this section.

(B) [Reserved]

(vi) At a minimum, you shall obtain valid CEMS hourly averages for 90 percent of the operating hours per calendar quarter and for 95 percent of the operating hours per calendar year that the affected unit is combusting municipal solid waste:

(A) At least 2 data points per hour shall be used to calculate each 1-hour arithmetic average.

(B) Each NO_X 1-hour arithmetic average shall be corrected to 7 percent oxygen on an hourly basis using the 1-hour arithmetic average of the oxygen (or carbon dioxide) continuous emissions monitoring system data.

(vii) The 1-hour arithmetic averages section shall be expressed in parts per million by volume (dry basis) and used to calculate the 24-hour daily arithmetic average concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under 40 CFR 60.13(e)(2).

(viii) All valid CEMS data must be used in calculating emissions averages even if the minimum CEMS data requirements of paragraph (e)(2)(iv) of this section are not met.

(ix) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS. The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the municipal waste combustor unit.

(3) If you are the owner or operator of an affected unit, you must determine compliance with the startup and shutdown requirements of paragraph (d) of this section by following the requirements in paragraphs (e)(3)(i) and (ii) of this section:

(i) You can measure CEMS data at stack oxygen content. You can dismiss or exclude CEMS data from compliance calculations, but you shall record and report CEMS data in accordance with the provisions of 40 CFR 60.59b(d)(7).

(ii) You shall determine compliance with the NO_X mass loading emissions limitation for periods of startup and shutdown by calculating the 24-hour average of all hourly average NO_X emissions concentrations from continuous emissions monitoring systems.

(A) You shall perform this calculations using stack flow rates derived from flow monitors, for all the hours during the 3-hour startup or shutdown period and the remaining 21 hours of the 24-hour period.

(B) [Reserved]

(4) If you are the owner or operator of an affected unit, you shall calculate municipal waste combustor unit capacity using the following procedures:

(i) For municipal waste combustor units capable of combusting municipal solid waste continuously for a 24-hour period, municipal waste combustor unit capacity shall be calculated based on 24 hours of operation at the maximum charging rate. The maximum charging rate shall be determined as specified in paragraphs (e)(4)(i)(A) and (B) of this section as applicable.

(A) For combustors that are designed based on heat capacity, the maximum charging rate shall be calculated based on the maximum design heat input capacity of the unit and a heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel.

(B) For combustors that are not designed based on heat capacity, the maximum charging rate shall be the maximum design charging rate.

(ii) For batch feed municipal waste combustor units, municipal waste combustor unit capacity shall be calculated as the maximum design amount of municipal solid waste that can be charged per batch multiplied by the maximum number of batches that could be processed in a 24-hour period. The maximum number of batches that could be processed in a 24-hour period is calculated as 24 hours divided by the design number of hours required to process one batch of municipal solid waste, and may include fractional batches (*e.g.,* if one batch requires 16 hours, then 24/16, or 1.5 batches, could be combusted in a 24-hour period). For batch combustors that are designed based on heat capacity, the design heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel shall be used in calculating the municipal waste combustor unit capacity in megagrams per day of municipal solid waste.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information, as applicable, for each affected unit consistent with the requirements of § 52.40(g).

(1) The calendar date of each record.

(2) The emissions concentrations and parameters measured using continuous monitoring systems.

(i) All 1-hour average NO_X emissions concentrations.

(ii) The average concentrations and percent reductions, as applicable, including all 24-hour daily arithmetic average NO_X emissions concentrations.

(3) Identification of the calendar dates and times (hours) for which valid hourly NO_X emissions, including reasons for not obtaining the data and a description of corrective actions taken.

(4) Identification of each occurrence that NO_X emissions data, or operational data (*i.e.,* unit load) have been excluded from the calculation of average emissions concentrations or parameters, and the reasons for excluding the data.

(5) The results of daily drift tests and quarterly accuracy determinations for CEMS, as required under 40 CFR part 60, appendix F, Procedure 1.

(6) The following records:

(i) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been provisionally certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(a) including the dates of initial and renewal certifications and documentation of current certification;

(ii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been fully certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(b) including the dates of initial and renewal certifications and documentation of current certification;

(iii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have completed the EPA municipal waste combustor operator training course or a State-approved equivalent course as required by 40 CFR 60.54b(d) including documentation of training completion; and

(iv) Records of when a certified operator is temporarily off site. Include two main items:

(A) If the certified chief facility operator and certified shift supervisor are off site for more than 12 hours, but for 2 weeks or less, and no other certified operator is on site, record the dates that the certified chief facility operator and certified shift supervisor were off site.

(B) When all certified chief facility operators and certified shift supervisors are off site for more than 2 weeks and no other certified operator is on site, keep records of four items:

(*1*) Time of day that all certified persons are off site.

(*2*) The conditions that cause those people to be off site.

(*3*) The corrective actions taken by the owner or operator of the affected unit to ensure a certified chief facility operator or certified shift supervisor is on site as soon as practicable.

(*4*) Copies of the reports submitted every 4 weeks that summarize the actions taken by the owner or operator of the affected unit to ensure that a certified chief facility operator or certified shift supervisor will be on site as soon as practicable.

(7) Records showing the names of persons who have completed a review of the operating manual as required by 40 CFR 60.54b(f) including the date of the initial review and subsequent annual reviews.

(8) Records of steps taken to minimize emissions during startup and shutdown as required by paragraph (d)(5) of this section.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include all information required by paragraph (e) of this section, including CEMS data to demonstrate compliance with the applicable emissions limits under paragraph (c) of this section.

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):

■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and

■ ii. 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, § 52.45, or § 52.46 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart O—Illinois

■ 8. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart P—Indiana

■ 9. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart S—Kentucky

■ 10. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart T—Louisiana

■ 11. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart V—Maryland

■ 12. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart X—Michigan

■ 13. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Y—Minnesota

■ 14. Amend § 52.1240 by adding paragraph (d) 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.

Subpart Z—Mississippi

■ 15. Amend § 52.1284 by:
■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
■ b. In newly redesignated paragraph (a)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart AA—Missouri

■ 16. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart DD—Nevada

■ 17. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart FF—New Jersey

■ 18. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart HH—New York

■ 19. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart KK—Ohio

■ 20. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart LL—Oklahoma

■ 21. Amend § 52.1930 by:
■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
■ b. In newly redesignated paragraph (a)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. 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:

§ 52.1930 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart NN—Pennsylvania

■ 22. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart SS—Texas

■ 23. Amend § 52.2283 by:
■ a. In paragraph (d)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart TT—Utah

■ 24. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart VV—Virginia

■ 25. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart XX—West Virginia

■ 26. 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, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart YY—Wisconsin

■ 27. Amend § 52.2587 by:
■ a. In paragraph (e)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ b. Revising paragraph (e)(3); and
■ c. Adding paragraphs (e)(4) and (5).

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.

PART 75—CONTINUOUS EMISSION MONITORING

■ 28. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q and 7651k note.

Subpart H—NO_X Mass Emissions Provisions

■ 29. 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.

* * * * *

■ 30. 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 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 heading to paragraph (f)(2); and

■ i. Revising paragraph (f)(4).

The revisions and additions read 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 (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 that is subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter, that lists coal or a solid coal-derived fuel as a fuel in the unit's monitoring plan under § 75.53 for any portion of the ozone season in the year for which data are being reported, that serves a generator of 100 MW or larger nameplate capacity, and that is not a circulating fluidized bed boiler, provided that through December 31, 2029, the requirements under this paragraph (f)(1)(x) shall apply to a unit in a given calendar year only if the unit also was equipped with selective catalytic reduction controls on or before September 30 of the previous year:

(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;

(E) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season; and

(F) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season by more than 50 tons, calculated as the remainder of the amount calculated under paragraph (f)(1)(x)(E) of this section minus 50, but not less than zero.

(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).

■ 31. 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.

■ 32. 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. Procedures for Heat Input

* * * * *

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

* * * * *

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 to this appendix, 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. Procedures for NO_X Mass Emissions

* * * * *

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 this appendix 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 this appendix 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 to this appendix.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h} t_h$$

(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 to this appendix:

$$E_{(NOX)_i} = E_{(NOX)_{CS}} \left(\frac{t_{CS}}{t_i}\right) \left[\frac{HI_i t_i}{\sum_{i=1}^{n} HI_i t_i}\right]$$

(Eq. F-28)

Where:

$E_{(NOX)i}$ = Apportioned NO_X mass emission rate for the hour for unit ''i'', lb/hr.

$E_{(NOX)CS}$ = NO_X mass emission rate for the hour at the common stack, lb/hr.

HI_i = Heat input rate for the hour for unit ''i'','' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b to this appendix, 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

■ 33. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 34. Amend § 78.1 by:

■ a. In paragraphs (b)(13)(i), (b)(14)(i), (b)(15)(i), (b)(16)(i), and (b)(17)(i), removing ''decision on the'' and adding in its place ''calculation of an'';

■ b. In paragraph (b)(17)(viii), adding ''or (e)'' after ''§ 97.826(d)'';
■ c. In paragraph (b)(17)(ix), adding ''or (e)'' after ''§ 97.811(d)'';
■ d. In paragraph (b)(18)(i), removing ''decision on the'' and adding in its place ''calculation of an''; and
■ e. 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 calculation of a dynamic trading budget under § 97.1010(a)(4) of this chapter.

(ii) The calculation of an 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

■ 35. 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]

■ 36. 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]

■ 37. 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]

■ 38. 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''.

§ 97.426 [Amended]

■ 39. In § 97.426, amend paragraph (c) by:
■ a. Removing ''set forth in'' and adding in its place ''established under''; and
■ b. 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]

■ 40. 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'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. 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]

■ 41. 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]

■ 42. 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''.

■ 43. Amend § 97.526 by:

■ a. In paragraph (c):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. 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 ''§ 52.38(b)(2)(ii) of this chapter (or Indian'' and adding in its place ''§ 52.38(b)(2)(i)(B) of this 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)(ii)(B) 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)(ii)(C) 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]

■ 44. 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''; 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]

■ 45. 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]

■ 46. 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''.

§ 97.626 [Amended]

■ 47. In § 97.626, amend paragraph (c) by:

■ a. Removing ''set forth in'' and adding in its place ''established under''; and

■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 48. 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''.

The addition reads as follows:

§ 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]

■ 49. 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]

■ 50. 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''.

§ 97.726 [Amended]

■ 51. In § 97.726, amend paragraph (c) by:
■ a. Removing ''set forth in'' and adding in its place ''established under''; and
■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

§ 97.734 [Amended]

■ 52. 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

■ 53. 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'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. 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.

* * * * *

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]

■ 54. Amend § 97.806 by:
■ a. In paragraphs (c)(2)(i) introductory text, (c)(2)(i)(B), and (c)(2)(iii) and (iv),

removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ b. In paragraph (c)(3)(i), removing ''paragraph (c)(1)'' and adding in its place ''paragraphs (c)(1) and (2)''; and

■ c. Removing and reserving paragraph (c)(3)(ii).

§ 97.810 [Amended]

■ 55. 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)(20)(i) through (iii), (a)(23)(i) through (iii), and (b)(1), (2), (12), (13), (17), (20), and (23) by removing ''and thereafter'' and adding in its place ''through 2022''.

■ 56. 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 (e)(1) 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 August 4, 2023, 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 August 21, 2023, 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 (e)(4)(ii), 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 (e)(4)(ii) 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]

■ 57. 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''.

§ 97.825 [Amended]

■ 58. 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.

■ 59. 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):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. 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)(A)'';

■ f. 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)(A) of this chapter (and'';

■ g. Redesignating paragraph (e) as paragraph (f) and adding a new paragraph (e); and

■ h. Revising newly redesignated paragraphs (f)(1) and (2).

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.

* * * * *

(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 September 18, 2023, 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—

(A) 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

(B) The product of 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) and (C) of this chapter multiplied by a fraction whose numerator is the number of days from August 4, 2023 through September 30, 2023, inclusive, and whose denominator is 153.

(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 September 18, 2023, 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) 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)(ii)(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 a control period in 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) 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)(ii)(C) 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 a control period in 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.

Subpart FFFFF—Texas SO_2 Trading Program

■ 60. 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.

* * * * *

§ 97.934 [Amended]

■ 61. 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

■ 62. 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. In the definition of "Assurance account", removing "base CSAPR" and adding in its place "CSAPR";

■ e. Adding in alphabetical order a definition for "Backstop daily NO_X emissions rate";

■ f. Removing the definitions for "Base CSAPR NO_X Ozone Season Group 3 source" and "Base CSAPR NO_X Ozone Season Group 3 unit";

■ g. Adding in alphabetical order a definition for "Coal-derived fuel";

■ h. In the definition of "Common designated representative", removing "base CSAPR" and adding in its place "CSAPR";

■ i. Revising the definition of "Common designated representative's assurance level";

■ j. In the definition of "Common designated representative's share", removing "base CSAPR" and adding in its place "CSAPR" each time it appears;

■ k. In the definition of "Compliance account", adding "primary" before "emissions limitation";

■ l. Adding in alphabetical order a definition for "CSAPR NO_X Ozone Season Group 1 Trading Program";

■ m. 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";

■ n. In the definition of "CSAPR NO_X Ozone Season Group 3 allowance":

■ i. Adding "or (e)" after "§ 97.826(d)"; and

■ ii. Adding "or less" after "one ton";

■ o. In the definitions of "CSAPR NO_X Ozone Season Group 3 allowance deduction" and "CSAPR NO_X Ozone Season Group 3 emissions limitation", adding "primary" before "emissions limitation";

■ p. Adding in alphabetical order a definition for "CSAPR NO_X Ozone Season Group 3 secondary emissions limitation";

■ q. 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";

■ r. Adding in alphabetical order a definition for "CSAPR SO_2 Group 2 Trading Program";

■ s. 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".

■ t. In the definition of "Excess emissions", adding "primary" before "emissions limitation";

■ u. Adding in alphabetical order a definition for "Historical control period"; and

■ v. 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 a NO_X emissions rate 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).

* * * * *

Coal-derived fuel means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal.

* * * * *

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.1006(c)(2)(iii):

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 3 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 3 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 3 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 3 units in accordance with the CSAPR NO_X Ozone Season Group 3 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(11) or (12) of this chapter, multiplied by the sum 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) for such control period, and divided by such State NO_X Ozone Season Group 3 trading budget;

(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.

* * * * *

Historical control period means, for a unit as of a given calendar year, the period starting May 1 of a previous calendar year and ending September 30 of that previous calendar year, inclusive, without regard to whether the unit was subject to requirements under the CSAPR NO_X Ozone Season Group 3 Trading Program during such period.

* * * * *

■ 63. Amend § 97.1006 by:

■ a. Revising paragraph (b)(2), paragraph (c)(1) heading, paragraph (c)(1)(i), and paragraph (c)(1)(ii) introductory text;

■ b. Adding paragraphs (c)(1)(iii) and (iv);

■ c. In paragraphs (c)(2)(i) introductory text and (c)(2)(i)(B), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ d. Revising paragraph (c)(2)(iii);

■ e. In paragraph (c)(2)(iv), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ f. Revising paragraph (c)(3); and

■ g. In paragraph (c)(6) introductory text, adding ''or less'' after ''one ton''.

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 excess, if any, over 50 tons of the sum, for all CSAPR NO_X Ozone Season Group 3 units at the source and all calendar days of the control period, of any NO_X emissions from such a unit on any calendar day of the control period exceeding the NO_X emissions that would have occurred on that calendar 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 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 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 CSAPR NO_X Ozone Season Group 3 units at 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) and (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) August 4, 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.

(ii) A 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.

* * * * *

■ 64. 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 through 2025 shall be as indicated in table 1 to this paragraph (a)(1)(i), 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, 2021–2025

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Alabama			13,211	6,379	6,489	6,489
Arkansas			9,210	8,927	8,927	8,927
Illinois	11,223	9,102	8,179	7,474	7,325	7,325
Indiana	17,004	12,582	12,553	12,440	11,413	11,413
Kentucky	17,542	14,051	14,051	13,601	12,999	12,472
Louisiana	16,291	14,818	14,818	9,363	9,363	9,107
Maryland	2,397	1,266	1,266	1,206	1,206	1,206
Michigan	14,384	12,290	9,975	10,727	10,275	10,275
Minnesota				5,504	4,058	4,058
Mississippi			6,315	6,210	5,058	5,037
Missouri			15,780	12,598	11,116	11,116
Nevada				2,368	2,589	2,545
New Jersey	1,565	1,253	1,253	773	773	773
New York	4,079	3,416	3,421	3,912	3,912	3,912
Ohio	13,481	9,773	9,773	9,110	7,929	7,929
Oklahoma			11,641	10,271	9,384	9,376

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD, 2021–2025—Continued

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Pennsylvania	12,071	8,373	8,373	8,138	8,138	8,138
Texas			52,301	40,134	40,134	38,542
Utah				15,755	15,917	15,917
Virginia	6,331	3,897	3,980	3,143	2,756	2,756
West Virginia	15,062	12,884	12,884	13,791	11,958	11,958
Wisconsin			7,915	6,295	6,295	5,988

(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, rounded to the nearest allowance, of the following prorated amounts:

(A) The product of the non-prorated trading budget for the portion of the 2023 control period before August 4, 2023, shown for the State in table 1 to paragraph (a)(1)(i) of this section (or zero if table 1 to paragraph (a)(1)(i) 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 August 4, 2023, inclusive, and whose denominator is 153; plus

(B) The product of the non-prorated trading budget for the portion of the 2023 control period on and after August 4, 2023, 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 August 4, 2023, through September 30, 2023, inclusive, and whose denominator is 153.

(2)(i) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2026 through 2029 shall be the preset trading budget indicated for the State and control period in table 2 to this paragraph (a)(2)(i), except as provided in paragraph (a)(2)(ii) of this section.

TABLE 2 TO PARAGRAPH (a)(2)(i)—PRESET TRADING BUDGETS BY CONTROL PERIOD, 2026–2029

[Tons]

State	2026	2027	2028	2029
Alabama	6,339	6,236	6,236	5,105
Arkansas	6,365	4,031	4,031	3,582
Illinois	5,889	5,363	4,555	4,050
Indiana	8,363	8,135	7,280	5,808
Kentucky	9,697	7,908	7,837	7,392
Louisiana	6,370	3,792	3,792	3,639
Maryland	842	842	842	842
Michigan	6,743	5,691	5,691	4,656
Minnesota	4,058	2,905	2,905	2,578
Mississippi	3,484	2,084	1,752	1,752
Missouri	9,248	7,329	7,329	7,329
Nevada	1,142	1,113	1,113	880
New Jersey	773	773	773	773
New York	3,650	3,388	3,388	3,388
Ohio	7,929	7,929	6,911	6,409
Oklahoma	6,631	3,917	3,917	3,917
Pennsylvania	7,512	7,158	7,158	4,828
Texas	31,123	23,009	21,623	20,635
Utah	6,258	2,593	2,593	2,593
Virginia	2,565	2,373	2,373	1,951
West Virginia	10,818	9,678	9,678	9,678
Wisconsin	4,990	3,416	3,416	3,416

(ii) If the preset trading budget indicated for a given State and control period in table 2 to paragraph (a)(2)(i) of this section is less than the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, then the State NO_X Ozone Season Group 3 trading budget for the State and control period shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(3) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2030 and thereafter shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(4) The Administrator will calculate the dynamic trading budget for each State and each control period in 2026

and thereafter in the year before the year of the control period as follows:

(i) The Administrator will include a unit in a State (and Indian country within the borders of the State) in the calculation of the State's dynamic trading budget for a control period if—

(A) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired, provided that including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit;

(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 for which the dynamic trading budget is being calculated; and

(C) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the dynamic trading budget is being calculated.

(ii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will calculate the heat input amount in mmBtu to be used in the budget calculation as follows:

(A) For each such unit, the Administrator will determine the following unit-level amounts:

(*1*) The total heat input amounts reported in accordance with part 75 of this chapter for the unit for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the dynamic trading budget is being calculated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter; and

(*2*) The average of the three highest unit-level total heat input amounts identified for the unit under paragraph (a)(4)(iv)(A)(*1*) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(B) For the State, the Administrator will determine the following state-level amounts:

(*1*) The sum for all units in the State meeting the criterion under paragraph (a)(4)(i)(A) of this section, without regard to whether such units also meet the criteria under paragraphs (a)(4)(i)(B) and (C) of this section, of the total heat input amounts reported in accordance with part 75 of this chapter for the historical control periods in the years two, three, and four years before the year of the control period for which the dynamic trading budget is being calculated, provided that for the historical control periods in 2022 and 2023, the total reported heat input amounts for Nevada and Utah as otherwise determined under this paragraph (a)(4)(ii)(B)(*1*) shall be increased by 13,489,332 mmBtu for Nevada and by 1,888,174 mmBtu for Utah;

(*2*) The average of the three state-level total heat input amounts calculated for the State under paragraph (a)(4)(ii)(B)(*1*) of this section; and

(*3*) The sum for all units identified for inclusion in the calculation of the State's dynamic trading budget for the control period under paragraph (a)(4)(i) of this section of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(A)(*2*) of this section.

(C) The heat input amount for a unit used in the calculation of the State's dynamic trading budget shall be the product of the unit-level average total heat input amount calculated for the unit under paragraph (a)(4)(ii)(A)(*2*) of this section multiplied by a fraction whose numerator is the state-level average total heat input amount calculated under paragraph (a)(4)(ii)(B)(*2*) of this section and whose denominator is the state-level sum of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(B)(*3*) of this section.

(iii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will identify the NO_X emissions rate in lb/mmBtu to be used in the calculation as follows:

(A) For a unit listed in the document entitled ''Unit-Specific Ozone Season NO_X Emissions Rates for Dynamic Budget Calculations'' posted at *www.regulations.gov* in docket EPA–HQ–OAR–2021–0668, 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 that document.

(B) For a unit not listed in the document referenced in paragraph (a)(4)(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*) 0.011 lb/mmBtu, for a simple cycle combustion turbine or a combined cycle combustion turbine other than an integrated coal gasification combined cycle unit;

(*2*) 0.030 lb/mmBtu, for 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)(4)(iii)(B)(*1*) or (*2*) of this section.

(iv) The Administrator will calculate the State's dynamic trading budget for the control period 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)(4)(i) of this section, of the product for each such unit of the heat input amount in mmBtu calculated for the unit under paragraph (a)(4)(ii) of this section multiplied by the NO_X emissions rate in lb/mmBtu identified for the unit under paragraph (a)(4)(iii) of this section.

(v)(A) By March 1, 2025 and March 1 of each year thereafter, the Administrator will calculate the dynamic trading budget for each State, in accordance with paragraphs (a)(4)(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 (a)(4)(v)(A) 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)(4)(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)(4)(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)(4)(v)(A) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(4)(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)(4)(v)(B) of this section.

(b) *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).

(c) *New unit set-asides.* (1) The new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 3 to this paragraph (c)(1):

TABLE 3 TO PARAGRAPH (c)(1)—NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	265	265
Indiana	262	254
Kentucky	309	283
Louisiana	430	430
Maryland	135	115
Michigan	500	482
New Jersey	27	27
New York	168	168
Ohio	291	290
Pennsylvania	335	339
Virginia	185	161
West Virginia	266	261

(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 2023 and thereafter shall be calculated as the product (rounded to the nearest allowance) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) of this section multiplied by—

(i) 0.09, for Nevada for the control periods in 2023 through 2025;

(ii) 0.06, for Ohio for the control periods in 2023 through 2025;

(iii) 0.05, for each State other than Nevada and Ohio for the control periods in 2023 through 2025; or

(iv) 0.05, for each State for each control period in 2026 and thereafter.

(d) *Indian country new unit set-asides for the control periods in 2021 and 2022.* The 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 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 4 to this paragraph (d):

TABLE 4 TO PARAGRAPH (d)—INDIAN COUNTRY NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	....	....
Indiana	....	....
Kentucky	....	....
Louisiana	15	15
Maryland	....	....
Michigan	13	12
New Jersey	....	....
New York	3	3
Ohio	....	....
Pennsylvania	....	....
Virginia	....	....
West Virginia	....	....

(e) *Variability limits.* (1) The variability limits for the State NO_X Ozone Season Group 3 trading budgets for the control periods in 2021 and 2022 for each State with such trading budgets for such control periods shall be as indicated in table 5 to this paragraph (e)(1).

TABLE 5 TO PARAGRAPH (e)(1)—VARIABILITY LIMITS BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	2,356	1,911
Indiana	3,571	2,642
Kentucky	3,684	2,951
Louisiana	3,421	3,112
Maryland	504	266
Michigan	3,021	2,581
New Jersey	329	263
New York	856	717
Ohio	2,831	2,052
Pennsylvania	2,535	1,758
Virginia	1,329	818
West Virginia	3,163	2,706

(2) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period in 2023 and thereafter shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) 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—

(A) The sum for all CSAPR NO_X Ozone Season Group 3 units in the State and Indian country within the borders of the State of the total heat input reported for the control period in mmBtu, provided that, for purposes of this paragraph (e)(2)(ii)(A), the 2023 control period for all States shall be deemed to be the period from May 1, 2023 through September 30, 2023, inclusive; divided by

(B) The state-level total heat input amount used in the calculation of the State NO_X Ozone Season Group 3 trading budget for the State and control period in mmBtu, as identified in accordance with paragraph (e)(3) of this section.

(3) For purposes of paragraph (e)(2)(ii)(B) of this section, the state-level total heat input amount used in the calculation of a State NO_X Ozone Season Group 3 trading budget for a given control period shall be identified as follows:

(i) For a control period in 2023 through 2025, and for a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the preset trading budget set forth for the State and control period in table 2 to paragraph (a)(2)(i) of this section, the state-level total heat input amounts shall be as indicated in table 6 to this paragraph (e)(3)(i).

TABLE 6 TO PARAGRAPH (e)(3)(i)—STATE-LEVEL TOTAL HEAT INPUT USED IN CALCULATIONS OF PRESET TRADING BUDGETS BY CONTROL PERIOD

[2023–2029 (mmBtu)]

State	2023	2024	2025	2026	2027	2028	2029
Alabama	313,037,541	333,030,691	333,030,691	330,396,046	328,650,653	328,650,653	307,987,882
Arkansas	192,843,561	192,843,561	192,843,561	190,921,052	190,921,052	190,921,052	190,921,052
Illinois	274,005,935	286,568,112	286,568,112	253,219,463	253,219,463	214,086,655	193,900,867
Indiana	356,047,916	330,175,944	330,175,944	302,245,332	302,245,332	277,218,546	236,611,101
Kentucky	301,161,750	301,161,750	295,857,697	295,857,697	295,857,697	293,016,485	274,595,978
Louisiana	280,592,592	280,592,592	278,766,253	278,461,807	277,262,840	277,262,840	277,262,840
Maryland	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007
Michigan	313,846,533	299,124,688	299,124,688	258,225,107	258,225,107	258,225,107	222,314,181
Minnesota	128,893,685	107,821,236	107,821,236	107,821,236	93,890,928	93,890,928	85,707,385
Mississippi	192,978,295	189,415,018	189,279,160	189,279,160	189,279,160	176,004,820	176,004,820
Missouri	284,308,851	249,153,661	249,153,661	249,153,661	248,413,545	248,413,545	248,413,545
Nevada	103,489,785	116,979,117	114,729,782	105,018,415	100,193,805	100,193,805	96,378,269
New Jersey	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231
New York	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661
Ohio	412,292,609	386,560,212	386,560,212	386,560,212	386,560,212	358,992,155	342,075,946
Oklahoma	212,903,386	211,187,283	211,165,691	211,145,820	196,160,642	196,160,642	196,160,642
Pennsylvania	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	487,590,728
Texas	1,395,116,925	1,395,116,925	1,389,251,813	1,389,251,813	1,356,192,532	1,320,040,162	1,280,014,875
Utah	164,519,648	166,407,822	166,407,822	127,217,396	127,217,396	127,217,396	127,217,396
Virginia	202,953,791	194,015,719	194,015,719	194,015,719	194,015,719	194,015,719	186,848,587
West Virginia	306,845,495	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957
Wisconsin	220,794,282	220,792,155	213,038,308	185,469,476	151,343,287	151,343,287	151,343,287

(ii) For a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, and for a control period in 2030 and thereafter, the state-level total heat input amount shall be the amount for the State and control period calculated under paragraph (a)(4)(ii)(B)(*2*) 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 an Indian country existing unit set-aside, a new unit set-aside, or an Indian country new unit set-aside but does not include any tons in a variability limit.

■ 65. Amend § 97.1011 by revising the section heading and paragraphs (a), (b), paragraph (c) heading, and paragraphs (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 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(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 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(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 2026 and thereafter.* For each control period in 2026 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 the Administrator will calculate default allocations shall be the remainder of the State NO_X Ozone Season Group 3 trading budget for the control period under § 97.1010(a) minus the new unit set-aside for the control period under § 97.1010(c).

(2) The Administrator will calculate a default allocation of CSAPR NO_X Ozone Season Group 3 allowances for each CSAPR NO_X Ozone Season Group 3 unit in the State and Indian country within the borders of the State meeting the following criteria:

(i) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired;

(ii) 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 for which the allowances are being allocated; and

(iii) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the allowances are being allocated.

(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 calculate an average heat input amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total heat input amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter.

(ii) The average heat input amount used in the allocation calculations shall be the average of the three highest total heat input amounts identified for the unit under paragraph (b)(3)(i) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(4) 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 calculate a tentative maximum allocation amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total NO_X emissions amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated.

(ii) The tentative maximum allocation amount used in the allocation calculations shall be the highest of the total NO_X emissions amounts identified for the unit under paragraph (b)(4)(i) of this section or, if less, any applicable amount calculated under paragraph (b)(4)(iii) of this section.

(iii)(A) The tentative maximum allocation amount under paragraph (b)(4)(ii) of this section for a unit described in paragraph (b)(4)(iii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the highest total heat input amount identified for the unit under paragraph (b)(3)(i) of this section in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For the control period in 2026, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported, that serves a generator with nameplate capacity of 100 MW or more, and that is equipped with selective catalytic reduction controls, except a circulating fluidized bed boiler.

(C) For each control period in 2027 and thereafter, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported and that serves a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

(5) 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)(6) of this section and will recalculate the unrounded default allocations according to the procedures in paragraph (b)(7) or (8) 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.

(6) 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 default allocations, of the units' average heat input amounts 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 amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iii) If the sum of the unrounded default allocations determined under paragraph (b)(6)(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)(7) or (8) of this section, as applicable.

(iv) If the sum of the unrounded default allocations determined under paragraph (b)(6)(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)(9) and (10) of this section.

(7) 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 tentative maximum allocation amount determined under paragraph (b)(4)(ii) 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 default allocations.

(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' tentative maximum allocation amounts determined under paragraph (b)(4)(ii) of this section, of the units' average heat input amounts 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 procedure was less than the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unit's unrounded default allocation 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)(7)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(7)(ii) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iv) Except as provided in paragraph (b)(7)(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)(7)(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)(7) of this section or follow the procedures in paragraph (b)(8) of this section, as applicable.

(vi) If the sum of the unrounded default allocations determined under paragraphs (b)(7)(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)(9) and (10) of this section.

(8) 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 tentative maximum allocation amount determined under paragraph (b)(4)(ii) 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 default allocations.

(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)(8)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section.

(9) The Administrator will round the default allocation for each eligible unit determined under paragraph (b)(6), (7), or (8) of this section to the nearest allowance and make any adjustments required under paragraph (b)(10) of this section.

(10) If the sum of the default allocations after rounding under paragraph (b)(9) 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)(9) 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.

(11)(i) By March 1, 2025 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 (10) 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 (b)(11)(i) 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)(11)(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)(11)(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)(11)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(11)(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)(11)(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 CSAPR NO_X Ozone Season Group 3 allowances were allocated to the recipient for such control period 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.

* * * * *

(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.

■ 66. 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 paragraph (a)(4)(i);

■ h. Redesignating paragraph (a)(4)(ii) as paragraph (a)(4)(iii) and adding a new paragraph (a)(4)(ii);

■ i. Revising paragraphs (a)(5) and (10):

■ j. 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'';

■ k. Adding paragraph (a)(13);

■ l. Revising paragraphs (b) introductory text and (b)(1) and (2);

■ m. 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'';

■ n. Revising paragraph (b)(10);

■ o. 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

■ p. 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(c) 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.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 3 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the control period or, if less, any applicable amount calculated under paragraph (a)(4)(ii) of this section.

(ii)(A) The allocation under paragraph (a)(4)(i) of this section to a unit described in paragraph (a)(4)(ii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the unit's total heat input during the control period in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For a control period in 2024 through 2026, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(C) For a control period in 2027 and thereafter, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

(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 (a)(13)(i) 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 referenced in § 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(d) 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 (b)(13)(i) 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.

■ 67. 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. Adding paragraphs (d) and (e);
■ e. In paragraph (f), removing "§ 97.1011(a), or" and adding in its place "§ 97.1011(a)(1), or";
■ f. Redesignating paragraphs (g) and (h) as paragraphs (i) and (j), respectively, and adding new paragraphs (g) and (h);
■ g. Revising newly redesignated paragraph (i);
■ h. In newly redesignated paragraph (j), removing "and May 1 of each year thereafter, the" and adding in its place ", and May 1, 2023, the"; 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 September 5, 2023, 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 September 5, 2023, 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 August 4, 2023, 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.

* * * * *

(g) By September 5, 2023, 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.

(h) 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 (h).

(i) 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).

* * * * *

■ 68. 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; backstop daily NO_X emissions rate.

* * * * *

(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 excess, if any, over 50 tons of the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all calendar days in the control period and all CSAPR NO_X Ozone Season Group 3 units at the source to which the backstop daily NO_X emissions rate applies 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 calendar day in pounds exceed the product in pounds of the unit's total heat input in mmBtu for that calendar day multiplied by 0.14 lb/mmBtu; or

* * * * *

(3) The backstop daily NO_X emissions rate of 0.14 lb/mmBtu applies as follows:

(i) For each control period in 2024 through 2029, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(ii) For each control in 2030 and thereafter, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

■ 69. Amend § 97.1025 by:
■ a. Revising the section heading;
■ b. In 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), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears; and
■ c. Adding paragraph (c).

The revision and addition 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 CSAPR NO_X Ozone Season Group 3 unit equipped with selective catalytic reduction controls or selective non-catalytic reduction controls 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 (c)(1) shall apply to a unit for a control period only if:

(i) The unit is included for the control period in a group of CSAPR NO_X Ozone Season Group 3 units at 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 historical 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 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 historical 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 historical control period shall be calculated from such reported data as the quotient (converted to lb/mmBtu at a conversion factor of 2,000 lb/ton, and rounded to the nearest 0.0001 lb/mmBtu) of the unit's total NO_X emissions in tons for the historical control period divided by the unit's total heat input in mmBtu for the historical control period.

■ 70. Amend § 97.1026 by:

■ a. Revising the section heading and paragraph (b);
■ b. In paragraph (c):
■ i. Removing ''set forth in'' and adding in its place ''established under''; and
■ ii. 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; bank recalibration.

* * * * *

(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 and thereafter, 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 year thereafter, 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 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.

(ii) 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 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 multiplied by—

(A) 0.210, for a control period in 2024 through 2029; or

(B) 0.105, for a control period in 2030 and thereafter.

(3) If the total amount of CSAPR NO_X Ozone Season Group 3 allowances determined under paragraph (d)(2)(i) of this section exceeds the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target 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)(ii) 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)(i) 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.

■ 71. 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)'' each time it appears.

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) August 4, 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, 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) January 31, 2024, 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.

* * * * *

■ 72. 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 August 4, 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)(C) of this chapter;

* * * * *

[FR Doc. 2023–05744 Filed 6–2–23; 8:45 am]

BILLING CODE 6560–50–P

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

EPA-88FR36654

Filed On: September 25, 2023

State of Utah, by and through its Governor, Spencer J. Cox, and its Attorney General, Sean D. Reyes,

Petitioner

v.

Environmental Protection Agency and Michael S. Regan, Administrator, U.S. EPA,

Respondents

City of New York, et al.,
Intervenors

Consolidated with 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1207, 23-1208, 23-1209, 23-1211

BEFORE: Pillard, Walker*, and Childs, Circuit Judges

O R D E R

Upon consideration of the motions for stay in Nos. 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1202, and 23-1205, the oppositions thereto, the replies, and the amicus briefs, it is

ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending court review. See Nken v. Holder, 556

* Judge Walker would stay the federal implementation plan in question.

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

U.S. 418, 434 (2009); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2021).

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Tatiana Magruder
Deputy Clerk

Technical Support Document (TSD)
for the Final Rule
Docket ID No. EPA-HQ-OAR-2021-0668

Final Non-EGU Sectors TSD

U.S. Environmental Protection Agency
Office of Air and Radiation
March 2023

This revised document replaces the version posted to EPA's website the morning of March 15, 2023. Revisions in this TSD include a revised title, date and slight changes to references supporting emissions limits/requirements for the Cement and Concrete Product Manufacturing industry. These revisions do not change any requirements in the final rulemaking.

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Table of Contents

1 Introduction/Purpose

The purpose of this Technical Support Document (TSD) is to discuss the basis for the final emissions limits and monitoring, recordkeeping, and reporting requirements for the following emissions unit types in non-EGU industries: engines in the Pipeline Transportation of Natural Gas industry; kilns in the Cement and Cement Product Manufacturing industry; boilers and reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing industry; furnaces in the Glass and Glass Product Manufacturing industry; high-emitting equipment and large boilers in the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Metal Ore Mining, and Pulp, Paper, and Paperboard Mills industries, and incinerators in the Municipal Waste Combustor industry. This TSD provides additional information to supplement the discussion in the preamble to the final rule on the basis for EPA's final emissions limits for each non-EGU unit and industry. All non-EGU emission limits identified in the final rule are set at a level that can be met through the installation of the control strategies identified in the preamble and further discussed in this TSD.

2 Pipeline Transportation of Natural Gas

Based on available information in the National Emissions Inventory (NEI), EPA has determined that reciprocating engines are the largest collective sources of nitrogen oxides (NO_X) emissions from the Natural Gas Transportation Industry in the states covered by this final FIP. As explained in the Non-EGU Screening Assessment memorandum, the largest potential NO_X emission reductions are from natural gas-fired spark ignition engines. Based on the NEI data, EPA has not identified a potential for significant emission reductions from turbines and compression ignition engines in this industry in the states covered by the final FIP. The process descriptions, background on each engine type, and summaries of applicable "reasonably available control technology" (RACT) emission limits and permit conditions, as well as a discussion of available NO_X controls, are summarized in an analysis developed by the Ozone Transport Commission entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions* (October 17, 2012) ("OTC Engine Study"). The three types of engines for which EPA is finalizing emission limits in this final FIP are: 1) two stroke lean burn spark ignition engines, which are covered on pages 17-28 of the OTC Engine Study; four stroke lean burn spark ignition engines, which are covered on pages 30-42 of the OTC Engine Study; and four stroke rich burn spark ignition engines, which are covered on pages 44-52 of the OTC Engine Study.

EPA is finalizing an applicability threshold for spark ignition engines of 1000 horsepower (hp) or more. Based on the Non-EGU Screening Assessment memorandum, engines with a potential to emit of 100 tpy or greater had the most significant potential for NO_X emissions reductions. EPA reviewed available information in the NEI and determined that many engines above 1000 hp reported emissions above 100 tpy, while engines smaller than 1000 hp generally reported emissions below 100 tpy.[1] Specifically, EPA only noted two engines below 1000 hp that emitted more than 100 tpy, while over 200 engines over 1000 hp emitted greater than 100 tpy. In addition to the NEI data, EPA observed that uncontrolled emissions from engines can be as high as 16.8 grams per horsepower per hour (g/hp-hr).[2] In addition, operating hours can be as high as 7000 hours in a given year.[3] With these assumptions, EPA could justify regulating engines around 800 hp or more. While the available data indicate that average operating hours are below 7000 hours per year,[4] in light of the potential variability in operating hours and the clear potential for these sources to emit in excess of 100 tons per year, EPA is

[1] *See* 2017 NEI Engines Emissions.xlsx, available in the docket for this rulemaking.
[2] *U.S. Environmental Protection Agency*, Stationary Reciprocating Internal Combustion Engines: Technical Support Document for NOx SIP Call (October 2003); *U.S. Environmental Protection Agency*, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD, 5-8 (August 2016); *Illinois Environmental Protection Agency*, Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines, 41 (March 19, 2007).
[3] *Illinois Environmental Protection Agency*, Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines, 41 (March 19, 2007).
[4] OTC Engine Study, 88 (October 17, 2012) (explaining that the average operating hours was around 35% or around 3066 hours a year); *Illinois Environmental Protection Agency*, Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines, 41 (March 19, 2007) (assuming operating hours for engines at 7000 hours a year); *U.S. Environmental Protection Agency*, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD, 5-6 through 5-9 (August 2016) (assuming operating hours of 2000 hours a year).

finalizing an applicability threshold of 1000 hp that is appropriately tailored to the scope of the screening assessment and should capture the majority of potential emission reductions.

Federal Rules Affecting Engines

Natural gas-fired spark ignition engines are subject to the New Source Performance Standards (NSPS) for Stationary Spark Ignition Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (40 CFR part 63, subpart ZZZZ).

Four Stroke Lean Burn Spark Ignition Engines

For four stroke lean burn spark ignition engines, EPA is finalizing an emissions limit of 1.5 g/hp-hr. EPA believes that installation of a selective catalytic reduction (SCR) system or a combination of other control technologies should be available for these engines to meet this emission limit. As explained in the OTC Engine Study, most of the four stroke lean burn spark ignition engines should be able to achieve 60 to 90% emission reductions with the installation of layered combustion controls, such as the installation of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc.[5] With reduction in this range, these engines should be able to achieve an emissions limit of 1.5 g/hp-hr or less. For some engines that can only achieve a 60% reduction from layered combustion controls, information suggests that those engines should be able to install SCR to lower emissions to 1.5 g/hp-hr.6 Further information about control measures to reduce NOx emissions from four stroke lean burn engines is shown below in the table excerpted from EPA's Menu of Control Measures for NAAQS Implementation.[7]

Many states containing ozone nonattainment areas or located within the Ozone Transport Region (OTR) have already adopted emission limits similar to or even significantly more stringent than the final emissions limit of 1.5 g/hp-hr. While some states have required limits equivalent to or even lower than 0.5 g/hp-hr,[8] most states have adopted emission limits at or close to 1.5 g/hp-hr.[9] Additional examples of state RACT rules and permitted emission limits can be found in the "NOx Permit Limits and RACT Tool spreadsheet" available in the docket. Many of these example RACT rules contain emission limits based on engine manufacture dates and set higher emissions limits between 1.5 and 3.0 g/hp-hr for older engines.

In addition to RACT limits, some four stroke lean burn spark ignition engines may have installed equipment to meet the emission limits contained within EPA's NSPS located at 40 CFR 60, subpart JJJJ, which requires that these engines meet a NOx emissions limit of 1.0 g/hp-hr if manufactured on or after July 1, 2010 and a NOx emissions limit of 2.0 g/hp-hr if manufactured

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[5] OTC Engine Study, 43.
[6] Id.
[7] EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022).
[8] See, e.g., South Coast Air Quality Management District Rule 1110.2, establishing a NO_X emissions limit of 36 ppmvd, which is equivalent to about 0.5 g/hp-hr.
[9] For example, see Colorado Air Quality Control Commission Regulation 7, Part E, Section I, Table 1 and Table 2 (establishing emissions limits at 0.7 to 2.0 g/hp-hr depending on engine construction dates).

on or after July 1, 2007 but before July 1, 2010.[10] Given that many of the newer engines subject to this FIP are already required to meet the more stringent NSPS limits of 1.0 to 2.0 g/hp-hr, EPA's final FIP is targeting an emission limit that older engines not subject to the NSPS could still meet.

Based on the example RACT rules, applicability of the NSPS to newer engines, and the feasibility of NO_X reductions analyzed in the OTC Engine Study, EPA believes an emissions limit of 1.5 g/hp-hr is achievable by the vast majority of four stroke lean burn spark ignition engines and will achieve the necessary NO_X reductions for engines that are not subject to equivalent RACT requirements or the NSPS at 40 CFR 60, subpart JJJJ.

Four Stroke Rich Burn Spark Ignition Engines

For four stroke rich burn spark ignition engines, EPA is finalizing an emissions limit of 1.0 g/hp-hr. EPA believes that installation of non-selective catalytic reduction (NSCR) or a combination of other control technologies should be available for these engines to meet this emission limit. As explained in the OTC Engine Study, most of the four stroke rich burn spark ignition engines should be able to achieve 90 to 99% emission reductions with the installation of NSCR.[11] A 90 to 99% emission reduction should result in an emissions level of 1.0 g/hp-hr or less. Further information about control measures to reduce NOx emissions from four stroke rich burn engines is shown below in the table excerpted from EPA's Menu of Control Measures for NAAQS Implementation.

Many states containing ozone nonattainment areas or located within the Ozone Transport Region (OTR) have already adopted emission limits similar to the final emissions limit of 1.0 g/hp-hr. While some states have required limits equivalent to or even lower than 0.2 g/hp-hr,[12] most states have adopted emission limits at or close to 1.0 g/hp-hr.[13] Additional examples of state RACT rules and permitted emission limits can be found in the "NO_X Permit Limits and RACT Tool spreadsheet" available in the docket. Many of these example RACT rules contain emission limits based on engine manufacture dates and set higher emissions limits at or close to 1.0 g/hp-hr for older engines.

In addition to RACT limits, some four stroke rich burn spark ignition engines may have installed equipment to meet the emission limits contained within EPA's NSPS located at 40 CFR 60, subpart JJJJ, which requires that these engines meet a NOx emissions limit of 1.0 g/hp-hr if manufactured on or after July 1, 2010 and a NOx emissions limit of 2.0 g/hp-hr if manufactured on or after July 1, 2007 but before July 1, 2010. *See* 40 CFR part 60, subpart JJJJ, Table 1. Further, some of these same units will have already installed NSCR to comply with EPA's NESHAP for Stationary Reciprocating Internal Combustion Engines at 40 CFR Part 63 subpart ZZZZ. Even though the NESHAP at subpart ZZZZ does not regulate NO_X emissions, the

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[10] *See* 40 CFR part 60, Subpart JJJJ, Table 1.
[11] OTC Engine Study at 45-46.
[12] *See* Pennsylvania General Permit 5 for Natural Gas Production and Processing Facilities, establishing NO_X emissions limits for four stroke rich burn engines as low as 0.2 g/hp-hr.
[13] For example, see Colorado Air Quality Control Commission Regulation 7, Part E, Section I, Table 1 and Table 2 (establishing emissions limits at 0.5 to 2.0 g/hp-hr depending on engine construction dates).

installation of NSCR on these units should already provide the co-benefit of reducing NO_X emissions to the levels necessary to comply with the final FIP.

Based on the example RACT rules, applicability of the NSPS to newer engines, and the feasibility of NO_X reductions analyzed in the OTC Engine Study, EPA believes an emissions limit of 1.0 g/hp-hr is achievable by the vast majority of four stroke lean burn spark ignition engines and will achieve the necessary reductions.

Two Stroke Lean Burn Spark Ignition Engines

For two stroke lean burn spark ignition engines, EPA is finalizing an emissions limit of 3.0 g/hp-hr. EPA believes that installation of layered combustion controls or a combination of other control technologies should be available for these engines to meet this emission limit. As explained in the OTC Engine Study, most of the two stroke lean burn spark ignition engines should be able to achieve 60 to 90% emission reductions with the installation of layered combustion controls, such as the installation of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, and air/fuel ratio control. [14] Available information suggests that some engines that can only achieve a 60% reduction from layered combustion controls will only be able to meet an emission limit of 3.0 g/hp-hr or greater. While some of these engines could install SCR to achieve greater reductions, EPA does not have information indicating that manufacturers and models of two stroke learn burn spark ignition engines generally can install the necessary combination of layered combustion controls and SCR to achieve a more stringent limit.[15] Further information about control measures to reduce NOx emissions from four stroke lean burn engines is shown below in the table excerpted from EPA's Menu of Control Measures for NAAQS Implementation.

Many states containing ozone nonattainment areas or located within the OTR have already adopted emission limits similar to the final emissions limit of 3.0 g/hp-hr. While some states have adopted limits equivalent to or even lower than 0.5 g/hp-hr,[16] most states have adopted emission limits between 1.0 g/hp-hr and 3.0 g/hp-hr.[17] Additional examples of state RACT rules and permitted emission limits can be found in the "NO_X Permit Limits and RACT Tool spreadsheet" available in the docket. Many of these example RACT rules contain emission limits based on engine manufacture dates and set higher emissions limits closer to 3.0 g/hp-hr for older engines.

In addition to RACT limits, some two stroke lean burn spark ignition engines may have installed equipment to comply with EPA's NSPS at 40 CFR part 60, subpart JJJJ, which requires that these engines meet a NOx emissions limit of 1.0 g/hp-hr if manufactured on or after July 1, 2010 and a NOx emissions limit of 2.0 g/hp-hr if manufactured on or after July 1, 2007 but before July 1, 2010. *See* 40 CFR part 60, subpart JJJJ, Table 1. Given that many of the newer

[14] OTC Engine Study at 45-46.
[15] OTC Engine Study at 45-46.
[16] See South Coast Air Quality Management District Rule 1110.2, establishing a NO_X emissions limit of 36 ppmvd or about 0.5 g/hp-hr.
[17] For example, see Colorado Air Quality Control Commission Regulation 7, Part E, Section I, Table 1 and Table 2 (establishing emissions limits at 1.0 to 3.0 g/hp-hr depending on engine construction dates).

engines subject to this final FIP are already required to meet the more stringent NSPS limits of 1.0 to 2.0 g/hp-hr, EPA's final FIP is targeting an emission limit that older engines not subject to the NSPS could still meet.

Based on the example RACT rules, applicability of the NSPS to newer engines, and the feasibility of NO_X reductions analyzed in the OTC Engine Study, EPA believes an emissions limit of 3.0 g/hp-hr is achievable by the vast majority of four stroke lean burn spark ignition engines and will achieve the necessary reductions for engines that are not subject to equivalent RACT requirements or the NSPS at 40 CFR part 60, subpart JJJJ.

Additional Information on NOx Controls

EPA's Menu of Control Measures (MCM) provides state, local and tribal air agencies with information on existing criteria pollutant emission reduction measures as well as relevant information concerning the efficiency and cost effectiveness of the measures.[18] State, local, and tribal agencies may use this information in developing emission reduction strategies, plans and programs to assure they attain and maintain the NAAQS. The information from the MCM can also be found in the Control Measures Database (CMDB), a major input to the Control Strategy Tool (CoST), which EPA used in the NOx control strategy analysis included in the Non-EGU Screening Assessment memorandum.[19] Information about control measures to reduce NOx emissions from stationary internal combustion engines in service of the pipeline transportation of natural gas is tabulated below.

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[18] EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022).
[19] EPA, Control Measures Database (CMDB) for Stationary Sources, available at https://www.epa.gov/system/files/other-files/2021-09/cmdb_2021-09-02_0.zip (URL dated Janu ary 13, 2023).

Table 2.A: NO_X Controls Available for Natural Gas Fired Spark Ignition Engines

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Lean Burn ICE - NG	Air to Fuel Ratio Controller	20	This control is the use of air/fuel ratio adjustment to reduce NOx emissions. This control applies to gasoline powered internal combustion engines with uncontrolled NOx emissions greater than 10 tons per year.	CARB 2001, EPA 2018, RTI 2014
Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio	20	This control is the use of air/fuel ratio adjustment to reduce NOx emissions. This control applies to natural gas-fired internal combustion engines with uncontrolled NOx emissions greater than 10 tons per year. Capital and annual cost information was obtained from model engine data in the Alternative Control Techniques (ACT) Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA 1993c).	EPA 1993c, Pechan 1998a, Pechan 2006
Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio and Ignition Retard	30	This control is the use of air/fuel and ignition retard to reduce NOx emissions. This control applies to natural gas-fired internal combustion engines with uncontrolled NOx emissions greater than 10 tons per year. Capital and annual cost information was obtained from model engine data in the Alternative Control Techniques (ACT) Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA 1993c).	EPA 1993c, Pechan 2006
Internal Combustion Engines - Gas	Ignition Retard	20	This control is the use of ignition retard technologies to reduce NOx emissions. This applies to small (<4,000 HP) natural gas-fired IC engines with uncontrolled NOx emissions greater than 10 tons per year. Capital and annual cost information was obtained from model engine data in the Alternative Control Techniques (ACT) Document -- NOx Emissions from Stationary Reciprocating Internal Combustion Engines (EPA 1993c).	EPA 1993c, Pechan 1998a

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Lean Burn ICE - NG	Layered Combustion	97	Layered combustion - for Large Bore, 2 stroke, Lean Burn, Slow Speed (High Pressure Fuel Injection achieves 90% reduction; Turbocharging achieves 75% reduction; Precombustion chambers achieves 90% reduction; Cylinder Head Modifications). All retrofit combustion- related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).	OTC 2012, RTI 2014
Lean Burn ICE - NG	Layered Combustion	97	Layered combustion - 2 stroke, Lean Burn, NG (Air Supply; Fuel Supply; Ignition; Electronic Controls; Engine Monitoring). Evaluation for 3 most representative made/models of 2 stroke LB compressor engines. All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).	OTC 2012, RTI 2014
Lean Burn ICE - NG	Low Emission Combustion	80	Low Emission Combustion includes Precombustion chamber head and related equipment on a Lean Burn engine.	RTI 2014, SJVAPCD 2003, EPA 2018
Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Adjust Air Fuel Ratio and Ignition Retard	39	This control measure is for natural gas fired internal combustion engines where the firing technology is not specified as to Rich Burn or Lean Burn. Existing control measures are applied based on the estimated percentage of lean-burn engines (85%) and rich-burn engines (15%). Adjust Air to Fuel Ratio and Ignition Retard (NAFRIICGS) is used for lean-burn engines and NSCR (NNSCRINGI4) is used for rich-burn engines.	Pechan 2006, EPA 2007b, INGAA 2014, CSRA 2016

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Industrial NG ICE, 4cycle (rich)	Non-Selective Catalytic Reduction	90	NSCR is achieved by placing a catalyst in the exhaust stream of the engine. The exhaust passes over the catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20 (NJDEP 2003). Typical exhaust temperatures for effective removal of NOx are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness.	EPA 2007b, NJDEP 2003
Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Layered Combustion	95.95	This control measure is for natural gas fired internal combustion engines where the firing technology is not specified as to Rich Burn or Lean Burn. Existing control measures are applied based on the estimated percentage of lean-burn engines (85%) and rich-burn engines (15%). Layered combustion (NLCICE2SNG) is used for lean-burn engines and NSCR (NNSCRINGI4) is used for rich-burn engines.	EPA 2007b, OTC 2012, INGAA 2014, CSRA 2016
Industrial NG ICE, SCCs with technology not specified	Non-Selective Catalytic Reduction or Low Emission Combustion	87.45	This control measure is for natural gas fired internal combustion engines where the firing technology is not specified as to Rich Burn or Lean Burn. Existing control measures are applied based on the estimated percentage of lean-burn engines (85%) and rich-burn engines (15%). Low emission combustion (NLECICEGAS) is used for lean-burn engines and NSCR (NNSCRINGI4) is used for rich-burn engines.	EPA 2007b, CARB 2001, INGAA 2014, CSRA 2016
Lean Burn ICE - NG	Selective Catalytic Reduction	90	SCR can be used on Lean Burn, NG engines. Assumed SCR can meet NOx emissions of 0.89 g/bh-hr. This is a known technology, however there is indication that applicability is engine/unit specific.	OTC 2012, SJVAPCD 2003, CARB 2001, EPA 2018, RTI 2014

Reproduced from EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 13, 2023).

Applicability Requirements

EPA received comments requesting a clarification of the meaning of "pipeline transportation of natural gas." EPA is clarifying and narrowing the definition of "pipeline transportation of natural gas" to mean the transport or storage of natural gas prior to delivery to a local distribution company custody transfer station or to a final end-user (if there is no local distribution company custody transfer station). The revised definition of this term in § 52.41(a) is consistent with EPA's regulatory definition of "natural gas transmission and storage segment" in 40 CFR 60.5430(a) (Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015).

EPA is adding definitions of the terms "local distribution company" and "local distribution company custody transfer station" that are consistent with the definitions found in 40 CFR 98.400 (Subpart NN, Suppliers of Natural Gas and Natural Gas Liquids) and 40 CFR 60.5430(a) (Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015), respectively.

Commenters stated that emergency generators are currently exempt from requirements applicable to non-emergency RICE covered by both the relevant NSPS rule (Subpart JJJJ), as well as the relevant NESHAP rule (Subpart ZZZZ), and that although the NSPS and NESHAP standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the "potential to emit" in issuing air permits for emergency RICE. Following a review of comments, EPA is finalizing an exemption for emergency engines. "Emergency engine" is defined to mean any stationary reciprocating internal combustion engine that is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc. Under the provisions of this rule, facilities may operate their emergency stationary RICE for limited non-emergency purposes for a maximum of 100 hours per calendar year.

Emission Limits and Compliance Requirements

In setting the emission limits for the Pipeline Transportation of Natural Gas, EPA reviewed state and local air agency rules, RACT NOx rules, NSPS rules applicable to newer engines, active air permits issues to sources with similar engines and the feasibility of NOx reductions analyzed in the OTC Engine Study. While some permits and rules reviewed express engine emissions limits in parts per million by volume (ppmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). Based on the available information for this industry, EPA is finalizing the following emissions limits expressed in terms of g/hp-hr for stationary SI engines in the covered states. Beginning in the 2026 ozone season and in each ozone season thereafter, the NOx emissions limits shown in the following table apply, based on a 30-day rolling average emissions rate during the ozone season:

Table 2.B: Final NOX Emissions Limits

Engine Type and Fuel	Final 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

Generally, the emission limits in Table 2.B can be met through installation and operation of the following controls: 1) NSCR on four stroke rich burn engines; 2) SCR on four stroke lean burn engines; and 3) layered combustion on two stroke lean burn engines.

In response to industry concern about the number of units captured by the proposed applicability criteria, EPA has made several changes to the applicability criteria as noted above in the *Applicability Requirements* subsection and to the emissions limits requirements in the final rule to focus the control requirements on impactful non-EGU units. Based upon EPA's 2019 NEI emissions inventory data, EPA estimates that a total of 3,005 stationary SI engines are subject to the final rule. EPA recognizes that many low-use engines are captured by the 1,000 hp design capacity applicability threshold.

Several commenters raised concerns about the proposed rule and asserted that compliance flexibility should be allowed where the installation of NOx controls is infeasible or cost-ineffective. Commenters recommended that EPA promulgate emissions averaging provisions as a remedy, as it promulgated in the 2004 NOX SIP Call Phase 2 rule, in which EPA evaluated and supported reliance on emissions averaging for RICE in the Pipeline Transportation of Natural Gas industry sector.

EPA reviewed past EPA guidance and rulemaking in which averaging plans were considered or recommended. In 1998, EPA issued the NOx SIP Call requiring certain states to reduce their NOx emissions as a means to reduce interstate ozone pollution. In 2002, EPA issued a memorandum providing guidance to the States that chose to adopt rules covering stationary RICE as part of their response to the 1998 NOx SIP Call.[20] This memo encouraged flexibility for RICE owners/operators in terms of their choices of control technology and the size of engines to be controlled, so long as each state's total budget was met. While EPA did not promulgate averaging provisions in the 2004 NOx SIP Call Phase 2 rule, we referred back to the 2002 Wegman memorandum and again noted that states that chose to regulate IC engines were encouraged to consider such flexibilities, so long as it could be demonstrated that the control measures in the SIP are collectively adequate to comply with the state's NO_X budget. *See* 69 FR

[20] Memorandum: "State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NOx) –Stationary Reciprocating Internal Combustion Engines", L. Wegman, US EPA OAQPS, August 22, 2002.

at 21621. The 2002 memorandum and the 2004 NOx SIP Call Phase 2 rule provide a backdrop for existing state rules allowing facility-wide averaging of NOx emissions.

EPA conducted research into several states' air quality rules containing emissions averaging plan provisions to review potential models using existing regulatory frameworks and methodologies. EPA considered relevant regulations in Colorado, Illinois, Michigan, New Jersey, New Mexico, Oklahoma, Pennsylvania, Tennessee, and Wisconsin.

The table below summarizes state provisions that allow for NOx emissions averaging. As indicated in the second column, nearly all of these provisions address emissions averaging across all RICE addressed by that State's regulations. The exception is for Texas, which allows for averaging required NOx reductions for grandfathered RICE in natural gas gathering and transmission. In the table, the "Facility Definition(s)" column summarizes key differences among the states in how a "facility" is represented in the averaging plan. Key differences in state rules include:

- Whether units allowed to be averaged are within a single facility or whether multiple facilities can be averaged (e.g., a "system-wide averaging plan");
- If multiple facilities can be addressed with a single plan:
    - Geographic limitations: for example, only units at facilities within the same ozone nonattainment area (NAA) can be included in the same plan
    - Control over operation of emissions units: most states require that all emission units be under common operational control;
- Emissions units for inclusion in a state plan: most state plans did not specify whether only affected (e.g., State RACT) units were to be included in the plan or if non-affected units could also be included. Ohio's approach provides for both affected and non-affected units to be included.
- Most states allow units to be excluded from the averaging plan, if they are otherwise compliant with the applicable defined RACT limit for that source.

The fifth column of Table 1 summarizes the specifications for NOx emissions averaging. This includes whether ozone season limitations are involved, or if annual limits are also required. For ozone season emissions, we also evaluated whether these are measured on a total seasonal basis (e.g. tons per ozone season) or on an average ozone season daily basis (e.g., on a rolling 30-day average).

The final column of the table shows exemptions for certain types of RICE. Note that these are exemptions from State NOx emissions rules, rather than exemptions from averaging plan programs.

Table 2.C. Existing State Regulations Containing Facility Averaging Plan Provisions for RICE NOx Reductions

State	RICE Coverage; Citation[a]	Affected Natural Gas RICE Units	Facility Definition(s)	Form of NOx Cap	Unit Exemptions
IL	All; Ill. Admin. Code title 35, § 217.386-390	• RICE =/>500 bhp	• Units at single "sources" (PTE>100 tpy NOx) or multiple "sources" under common control; Chicago area counties • Specified RICE, mainly pipeline units statewide	• Ozone season tons • Calendar year tons	• Emergency/Standby • Research, landfill gas, agricultural purpose • Nonstationary and <1,500 bhp
LA	All; Title 33, Chapter 22, § 2201	• Baton Rouge NAA: Rich and lean burn =/>150 bhp • NAA region of influence: lean burn =/>1500 bhp; rich burn =/>300 bhp	• Units at single facilities (PTE>25 tpy NOx) in the Baton Rouge NAA or (PTE>/= 50 tpy) in the NAA region of influence • Units located in multiple NAA or region of influence under common control	• OSD daily; 30 day rolling average, or • Ozone season lb/hr cap	• Emergency/Standby • Research, landfill gas, agricultural purpose, performance/ verification testing • Firefighting training • Flood control • Use for powering other engines
MI	All; R 36.1818	• "Large NOx SIP Call Engines": >1 ton per average OSD in 1995	• Units at single facilities or multiple facilities in the MI fine grid zone under common control	• </= total 2007 ozone season NOx	• None specified
NJ	All; N.J.A.C. 7:27-19	• Rich or lean burn >500 bhp • Lean burn >200 and <500 bhp	• No specifications provided for averaging units in separate facilities	• OSD daily actual < allowable • Non-OSD monthly actual < allowable	• None specified

State	RICE Coverage; Citation[a]	Affected Natural Gas RICE Units	Facility Definition(s)	Form of NOx Cap	Unit Exemptions
NY	All; 6 NYCRR § 227-2.5	• RICE >200 bhp inside severe ozone NAA • RICE >400 bhp outside severe ozone NAA	• Referred to as a "system." Multiple emission sources at different facilities in the same ozone NAA can be included in the system averaging plan. • Can include multiple owners/ operators	• Maintain "weighted average permissible emissions rate" from the plan.	• Emergency generators • Research and development or quality assurance testing
OH	All; Ohio Admin. Code 3745-110-03(I)	• RICE >500 bhp	• No specification for operational control • Affected and non-affected sources can be included	• Actual NOx tpy < allowable NOx tpy	• Engine testing operations • Permitted units with permitted restrictions resulting in <25 tpy NOx • Affected units with capacity factors of <10% annually during a 3-yr rolling average
OK	All; OAC Title 252, Chapter 100, Subchapter 11	• All fuel burning equipment >50 MMBtu/hr	• Multiple facilities can be included which are on adjacent properties and affect the same airshed • Multiple facilities must be under control of the same owner or operator	• Actual NOx emissions < allowable NOx, no averaging time specified	• None specified
PA	All; PA Title 25, § 129	• RICE >500 bhp	• Multiple units at a facility can be included or units at multiple facilities for system-wide averaging • Facilities within a system must be within the same NAA • Facilities must be under control of the same owner or operator	• Actual NOx emissions </= allowable NOx, 30-day rolling average	• Units with PTE <1 tpy NOx

State	RICE Coverage; Citation[a]	Affected Natural Gas RICE Units	Facility Definition(s)	Form of NOx Cap	Unit Exemptions
			• Each unit must be subject to a NOx RACT emissions limit		
TX	Natural gas gathering or transmission RICE; 30 TAC §116.779(b)(3)	• All grandfathered RICE	• Specific provisions provided for grandfathered RICE used in natural gas gathering and transmission; allows averaging of required NOx reduction across units (50% east TX region; 20% west TX region • Averaging of reductions across east and west TX regions; but reductions achieved in east region must =/> required reductions	• Actual NOx emissions < allowable NOx, no averaging time specified	• None specified
VA	All: 9VAC5, Chapter 40, §§ 7370 – 7540	• RICE >/=450 bhp	• No specifications for averaging plans are present; but since RACT for RICE NOx limitations are not specified, a case-specific plan is required. Conceivably, that plan could include an averaging approach.	• Actual NOx emissions < allowable NOx, no averaging time specified	• Emergency generators
WI	All; Wis. Adm. Code Chapter NR 428, § 428.25 (1)	• RICE =/>1000 bhp	• Multiple units at one facility can be included as well as averaging across facilities • Multiple owners/operators can be included	• Actual ozone season NOx < Allowable ozone season NOx • Actual annual NOx < Allowable annual NOx	• Units used to restart electricity generating units; Fire emergency water pumps; research & development units; engine testing • Backup generators operating <500 hours/yr or <200 hours during the ozone season

State	RICE Coverage; Citation[a]	Affected Natural Gas RICE Units	Facility Definition(s)	Form of NOx Cap	Unit Exemptions
					• <10% annual capacity factor, 3-yr rolling basis or <20% for utility owned engines

Abbreviations: bhp – brake horse-power; MMBtu/hr – million British thermal units per hour; MW – megawatt; NAA – nonattainment area; OSD – ozone season day; PTE – potential to emit; RICE – reciprocating internal combustion engine; tpy – tons per year

[a]Weblinks to state regulatory text:

IL: https://pcb.illinois.gov/documents/dsweb/Get/Document-11928/ (URL dated February 6, 2023).
LA: https://deq.louisiana.gov/assets/docs/Air/Enforcement/Title33.pdf (URL dated February 6, 2023).
MI: https://www.michigan.gov/-/media/Project/Websites/egle/Documents/Laws-Rules/AQD/apc-part8-2009-05-28-amended.pdf?rev=9194185cf0f7489e83c8c906be6bbea8 (URL dated February 6, 2023).
NJ: https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf (URL dated February 6, 2023).
NY: https://www.dec.ny.gov/regs/2492.html (URL dated February 6, 2023).
OH: https://codes.ohio.gov/ohio-administrative-code/rule-3745-110-03 (URL dated February 6, 2023).
OK: https://www.deq.ok.gov/wp-content/uploads/deqmainresources/100.pdf (URL dated February 6, 2023).
PA: http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/s129.98.html&d=reduce (URL dated February 6, 2023).
TX: https://www.tceq.texas.gov/assets/public/legal/rules/rules/pdflib/116h.pdf (URL dated February 6, 2023).
VA: https://www.deq.virginia.gov/home/showpublisheddocument/4168/637461452622230000 (URL dated February 6, 2023).
WI: https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf (URL dated February 6, 2023).

EPA conducted an analysis to evaluate the anticipated effect of a facility-wide emissions averaging compliance alternative. To estimate the number of facilities that may take advantage of the Facility-Wide Averaging Plan provisions, and the number of affected units that would install controls under such an emissions averaging plan, EPA conducted an analysis on a subset of the estimated 3,005 stationary IC engines subject to the final rule. EPA evaluated the reported actual NO_X emissions data in tpy from a subset of facilities in the covered states using 2019 NEI data for stationary IC engines with design capacities of 1,000 hp or greater. Using this subset of facilities, EPA then identified a number of facilities that have more than one affected engine, calculated each facility's emissions "cap" as the total NO_X emissions (in tons per year (tpy)) allowed facility-wide based on the unit-specific NO_X emissions limits applicable to all affected units at the facility, and identified a number of higher-emitting engines at each facility that were candidates for having controls installed. For engines that EPA identified were likely to install controls, EPA assumed that four stroke rich burn engines, four stroke lean burn engines, and two stroke lean burn engines could achieve a NO_X emissions rate of 0.5 g/hp-hr with the installation of SCR based on data obtained from the Ozone Transport Commission report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012). For the remaining engines identified as uncontrolled, EPA assumed a NO_X emissions rate of 16 g/hp-hr for all engine types. Thus, under the assumed averaging scenarios, engines with controls installed would achieve emissions levels below the emissions limits in the final rule and would offset the higher emissions from the remaining uncontrolled units. EPA then calculated the total facility-wide emissions (in tpy) under various assumed averaging scenarios and compared those totals to each facility's calculated emissions cap (in tpy) to estimate the number of affected units at each facility that would need to install controls to ensure that total facility-wide emissions remained below the emissions cap.

For each facility in the subset, the next step in the analysis was to determine the average of the actual 2019 NEI emissions (tpy) of only engines for which no controls had been applied in the previous cap compliance step. The average actual 2019 emissions (tpy) for facilities in this subset was found to be 21 tpy NOx emissions. The next step in the analysis was to apply the 21 tpy uncontrolled emissions (tpy) threshold to the entire estimated 3,005 stationary IC engines subject to the rule. The application of this threshold to the engines subject to the final rule determined the estimated number of affected engines that would be expected to have controls installed under a facility-wide emissions averaging plan scenario. Based on this analysis, EPA found that emissions averaging should allow most facilities to install controls on approximately one-third of the engines at their sites, on average, while complying with the applicable NO_X emissions cap on a facility-wide basis.

Following a review of public comments and evaluating the results of the analysis conducted, EPA is finalizing a facility-level emissions averaging provision as an alternative means of compliance with the emissions limits established in § 52.41(c). The requirements that we are finalizing for engines in the Pipeline Transportation of Natural Gas industry include provisions allowing source owner/operators to request EPA approval of facility-wide emissions averaging plans, which will enable owners and operators of affected units to take costs, installation timing needs, and other considerations into account in deciding which affected engines to control. Facility-wide emissions averaging plans will allow facility owners and operators to determine how to best achieve the necessary emissions reductions by installing controls on the affected engines with the greatest emissions reduction potential rather than on units with lower actual emissions where the installation of controls would be less cost effective.

An owner or operator of a facility containing more than one affected unit may elect to use an EPA-approved Facility-Wide Averaging Plan as an alternative means of compliance with the NO_X emissions limits in § 52.41(c). An approved Facility-Wide Averaging Plan will allow the owner or operator of the facility to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (i.e., by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control). So long as all of the emissions units covered by the Facility-Wide Averaging Plan collectively emit less than or equal to the total amount that would be emitted if each covered unit individually met the applicable NO_X emissions limitations, the covered units will be in compliance with the final rule. Under this alternative compliance option, facilities have the flexibility to prioritize emissions reductions from larger, dirtier engines.

The owner or operator of such a facility that elects to use a facility-wide emissions averaging plan must submit a request to EPA that, among other things, specifies the affected units that will be covered by the plan, provides facility and unit-level identification information, identifies a facility-wide emissions "cap" (in tpd) that the facility must comply with on a 30-day rolling average basis, and provides the calculation methodology used to demonstrate compliance with the identified emissions cap. The final rule defines "cap" to mean "the total amount of NOx emissions, in tons per day on a 30-day rolling average basis, that is collectively allowed from all of the affected units covered by a Facility-Wide Averaging Plan and is calculated as the sum each affected unit's NOx emissions at the emissions limit applicable to such unit under paragraph (c) of this section, converted to tons per day in accordance with [section 52.41(d)(3)]." The calculation of a facility's emissions "cap" is based in part on each affected unit's average daily operating hours. EPA will approve a request for a Facility-Wide Averaging Plan if EPA determines that the facility-wide emissions total (in tpd), based on a 30-day rolling emissions average basis during the ozone season, is less than the emissions cap (in tpd) and the plan establishes satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, recordkeeping requirements. In calculating the facility-wide emissions total during the ozone season, affected engines covered by the Facility-Wide Averaging Plan must be identified by each engine's nameplate capacity in horsepower, its actual operating hours during the ozone season, and its emissions rates in g/hp-hr from certified engine data or from the most recent performance test results for non-certified engines according to § 52.41(e). For affected engines that meet the certification requirements of § 60.4243(a), the facility-wide emissions calculations may be based on certified engine emissions standards data pursuant to § 60.4243(a), instead of performance tests. An affected unit listed in an EPA-approved Facility-Wide Averaging Plan cannot be withdrawn from such plan, and the terms of an approved Facility-Wide Averaging Plan may not be changed unless approved in writing by the Administrator.

Performance Tests and Monitoring

Affected units subject to this rule that operate NOx CEMS meeting specified requirements may use CEMS data to demonstrate compliance.

With respect to affected units that do not operate CEMS, EPA received comments concerning the proposed semi-annual NOx performance testing to demonstrate continual compliance. As commenters pointed out, the emissions limits in these final FIPs only apply during the ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to demonstrate continuous compliance during the ozone season. The final rule contains provisions requiring owners and operators of affected units that do not operate CEMS to conduct annual NOX performance tests, to monitor and record hours of operation and fuel consumption, and to use continuous parametric monitoring systems to demonstrate ongoing compliance with the applicable NOX emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance tests do not have to be conducted during the ozone season. Owners and operators of affected units must also reassess and adjust the site-specific operating parameters in accordance with the results of each performance test, and report and include ongoing site-specific operating parameter data in the annual reports to EPA and the semi-annual title V monitoring reports to the relevant air permitting authority.

3 Cement and Concrete Product Manufacturing

Process Description[21]

Cement kilns are used by the cement industry in the production of cement. Portland cement, used in almost all construction applications, is the industry's primary product. Essentially all of the NOx emissions associated with cement manufacturing are generated in the kilns because of high process temperatures.

Detailed information describing cement production can be found in Section 3 of the TSD to the proposal and is not repeated here.

Federal Rules Affecting Cement Plants

Cement plants are subject to the Portland Cement NESHAP (40 CFR part 63 subpart LLL) and NSPS (40 CFR part 60, subpart F). Cement kilns that burn hazardous waste are subject to the Hazardous Waste Combustor NESHAP (40 CFR part 63 subpart LLL). Cement kilns that burn non-hazardous solid wastes are subject to the Commercial and Industrial Solid Waste Incinerator Units (CISWI) rule (40 CFR part 60, subparts CCCC and DDDD).

The NSPS implementing Clean Air Act (CAA) section 111(b) for Portland Cement Plants was first promulgated at 40 CFR part 60, subpart F on December 23, 1971 (36 FR 24876). EPA conducted three additional reviews of these standards on June 14, 1974 (39 FR 20793), November 12, 1974 (39 FR 39874) and December 14, 1988 (53 FR 50354). NOx emissions were not regulated under part 60, subpart F at that time.

On June 16, 2008 (73 FR 34072), EPA proposed amendments to the NSPS for Portland Cement Plants. The proposed amendments included revisions to the emission limits for affected facilities which commence construction, modification, or reconstruction after June 16, 2008. Among other things, EPA proposed establishing a NOx emission limit for cement kilns at portland cement plants.[22]

On September 9, 2010 (75 FR 54970) EPA finalized the proposed amendments to the NSPS establishing a NOx emission limit, among other things, for portland cement plants that commence construction, modification, or reconstruction after June 16, 2008. This final rule became effective on November 8, 2010 and is codified at 40 CFR part 60 subpart F.

NOx Controls

The National Association of Clean Air Agencies (NACAA, formerly STAPPA/ALAPCO) has recommended requiring combustion controls and selective non-catalytic reduction (SNCR) to achieve NOx reductions of up to 70 percent on certain processes at

[21] See generally EPA, "AP-42 Compilation of Air Emissions Factors," Chapter 11, Mineral Products Industry, Section 11.6, Portland Cement Manufacturing, Final Section (January 1995).
[22] 73 FR 34072 (proposed NSPS for Portland Cement Plants), Docket IN No. EPA–HQ–OAR–2007–0877.

cement kilns.[23] SNCR is a post combustion control technology used to reduce NOx emissions without the presence of a catalyst. Reagent (Ammonia or Urea) is injected directly into flue gas and reacts with NOx resulting in Nitrogen (N_2) and water (H_2O).

SNCR avoids the problems related to catalyst fouling that occur during use of SCR technology but requires injection of the reagents in the kiln at a temperature between 1600 to 2000°F, which is much higher than the typical temperatures for SCR operation (550-800°F). At these temperatures urea decomposes to produce ammonia which is responsible for NOx reduction. Because of the temperature constraint, SNCR technology is only applicable to preheater and precalciner kilns.[24] Preheater and precalciner kilns require relatively simple SNCR installations. In preheater/precalciner kiln design, the SNCR injection ports can be installed in the combustion zone in the calciner, the oxidation zone of the upper air inlet before the deflection chamber, or in the area after the mixing chamber before the inlet to the bottom. SNCR has been installed and is currently operating on numerous kilns in Europe and the U.S.

SCR is a process that uses ammonia in the presence of a catalyst to selectively reduce NOx emissions from exhaust gases. This technology was at first widely used for NOx abatement in other industries, such as coal-fired power stations and waste incinerators. In SCR, anhydrous ammonia, usually diluted with air or steam, is injected through a grid system into hot flue gases which are then passed through a catalyst bed to carry out NOx reduction reactions. Ammonia is typically injected to produce a NH_3 to NOx molar ratio of 1.05-1.1:1 to achieve a NOx conversion of 80 to 90 percent with an ammonia "slip" of about 10 ppm of unreacted ammonia in the gases leaving the reactor. In the cement industry, basically two SCR systems are being considered: low dust exhaust gas and high dust exhaust gas treatment. Low dust exhaust gas systems require reheating of the exhaust gases after dedusting, resulting in additional cost. High dust systems are considered preferable for technical and economical reasons.[25] While SCR installations are not common at cement kilns in the U.S, EPA is aware of one SCR system that has been installed on a cement kiln in Joppa, Illinois.[26]

The European Union Commission charged with establishing the Best Available Techniques (BAT) to control NOx emissions from the production of cement outlines the following control techniques presented in Table 3.A below.

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[23] STAPPA/ALAPCO, Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options, 72-73 (July 1994).
[24] EPA, NOx Control Technologies for the Cement Industry: Final Report, 6 (September 2000).
[25] Official Journal of European Union Commission, Best Available Techniques (BAT) Conclusions Under Directive 2010/75/EU of the European Parliament and of the Council on Industrial Emissions for the Production of Cement, Lime and Magnesium Oxide, March 26, 2013, at 42.
[26] State of Illinois Clean Air Act Program Permit No. 95090119 (issued September 11, 2018, to Holcim US, Inc. - Joppa Plant, 2500 Portland Road, Grand Chain, IL 62941), Section 4.1 Cement Kilns and Clinker Coolers, Kiln #1. See also Lafarge, North America, Inc., Clean Air Act Settlement (overview of injunctive relief, available at https://www.epa.gov/enforcement/lafarge-north-america-inc-clean-air-act-settlement (URL dated October 12, 2021)).

Table 3.A: European Union Commission NOX BAT Controls

Primary Techniques/Measures	Description
Flame Cooling	The addition of water to the fuel or directly to the flame by using different injection methods, such as injection of one fluid (liquid) or two fluids (liquid and compressed air or solids) or the use of liquid/solid wastes with a high water content reduces the temperature and increases the concentration of hydroxyl radicals. This can have a positive effect on NOx reduction in the burning zone.
Low NOx Burners	Designs of low NOx burners (indirect firing) vary in detail but essentially the fuel and air are injected into the kiln through concentric tubes. The primary air proportion is reduced to some 6 - 10% of that required for stoichiometric combustion (typically 10 - 15% in traditional burners). Axial air is injected at high momentum in the outer channel. The coal may be blown through the center pipe or the middle channel. A third channel is used for swirl air, its swirl being induced by vanes at, or behind, the outlet of the firing pipe. The net effect of this burner design is to produce very early ignition, especially of the volatile compounds in the fuel, in an oxygen-deficient atmosphere, and this will tend to reduce the formation of NOx. The application of low NOx burners is not always followed by a reduction of NOx emissions. The set-up of the burner has to be optimized.
Mid Kiln Firing	In long wet and long dry kilns, the creation of a reducing zone by firing lump fuel can reduce NOx emissions. As long kilns usually have no access to a temperature zone of about 900 -1000°C, mid-kiln firing systems can be installed in order to be able to use waste fuels that cannot pass the main burner (for example tires). The rate of the burning of fuels can be critical. If it is too slow, reducing conditions can occur in the burning zone, which may severely affect product quality. If it is too high, the kiln chain section can be overheated - resulting in the chains being burned out. A temperature range of less than 1100°C excludes the use of hazardous waste with a chlorine content of greater than 1%.
Addition of mineralizers to improve the burnability of the raw meal (mineralized clinker)	The addition of mineralizers, such as fluorine, to the raw material is a technique to adjust the clinker quality and allow the sintering zone temperature to be reduced. By reducing/lowering the burning temperature, NOx formation is also reduced.
Staged combustion (conventional or waste fuels), also in combination	Staged combustion is applied at cement kilns with an especially designed precalciner. The first combustion stage takes place in the rotary kiln under optimum conditions for the clinker burning process. The second combustion stage is a burner at the kiln inlet, which produces a reducing

Primary Techniques/Measures	**Description**
with a precalciner and the use of optimized fuel mix	atmosphere that decomposes a portion of the nitrogen oxides generated in the sintering zone. The high temperature in this zone is particularly favorable for the reaction which reconverts the NOx to elementary nitrogen. In the third combustion stage, the calcining fuel is fed into the calciner with an amount of tertiary air, producing a reducing atmosphere there, too. This system reduces the generation of NOx from the fuel, and also decreases the NOx coming out of the kiln. In the fourth and final combustion stage, the remaining tertiary air is fed into the system as 'top air' for residual combustion.
SNCR	Selective non-catalytic reduction (SNCR) involves injecting ammonia water (up to 25% NH_3), ammonia precursor compounds or urea solution into the combustion gas to reduce NO to N_2. The reaction has an optimum effect in a temperature window of about 830 - 1050°C, and sufficient retention time must be provided for the injected agents to react with NO.
SCR	SCR reduces NO and NO_2 to Nitrogen with the help of NH_3 and a catalyst at a temperature range of 300 - 400°C. This technique was initially started for NOx abatement in other industries (coal fired power stations, waste incinerators) and is now available in the cement manufacturing industry.

Reproduced from Official Journal of European Union Commission, Best Available Techniques (BAT) Conclusions Under Directive 2010/75/EU of the European Parliament and of the Council on Industrial Emissions for the Production of Cement, Lime and Magnesium Oxide, March 26, 2013, Table 1.5.2.

EPA's Menu of Control Measures (MCM) provides state, local and tribal air agencies with information on existing criteria pollutant emission reduction measures as well as relevant information concerning the efficiency and cost effectiveness of the measures.[27] State, local, and tribal agencies may use this information in developing emission reduction strategies, plans and programs to assure they attain and maintain the NAAQS. The information from the MCM can also be found in the Control Measures Database (CMDB), a major input to the Control Strategy Tool (CoST), which EPA used in the NOx control strategy analysis included in the Non-EGU Screening Assessment memorandum.[28] Information about control measures to reduce NOx emissions from cement kiln operations is presented in Table 3.B below.

[27] EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022).
[28] EPA, Control Measures Database (CMDB) for Stationary Sources, available at https://www.epa.gov/system/files/other-files/2021-09/cmdb_2021-09-02_0.zip (URL dated January 6, 2022).

Table 3.B: List of NO_X Controls Available for Cement Kilns

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Cement kilns	Biosolid Injection Technology	23	This control is the use of biosolid injection to reduce NOx emissions. This control applies to cement kilns.	EPA 2006b, EPA 2007c
Cement kilns	Changing feed composition	25-40	This control is changing the cement formulation by adding steel slag to lower the clinkering temperatures and suppress NOx. The patented feed modification technique known as the CemStar Process is a raw feed modification process that can reduce NOx emissions by about 30 percent and increase production by approximately 15 percent. It involves the addition of a small amount of steel slag to the raw kiln feed. Steel slag has a chemical composition similar to clinker and many of the chemical reactions required to convert steel slag to clinker take place in the steel furnace. By substituting steel slag for a portion of the raw materials, facilities can increase thermal efficiency and thereby reduce NOx emissions. This control is applicable to wet- and dry-process kilns, as well as those with preheaters or precalciners.	STAPPA/ALAPCO 2006
Cement Kilns	Process Control Systems	<25	This control is the modification of the cement production process to improve fuel efficiency, increase capacity and kiln operational stability. NOx reductions result from the increase in productivity and reduced energy use. One process control that specifically targets NOx emissions is continuous emissions monitoring systems (CEMS). CEMS allow operators to continuously monitor oxygen and carbon monoxide (CO) emissions in cement kiln exhaust gases. The levels of these gases indicate the amount of	STAPPA/ALAPCO 2006

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			excess air in the combustion zone. At a given excess air level, NOx emissions increase as the temperature increases. Knowing the excess air level allows operators to maintain a lower temperature and thereby minimize NOx creation. Studies indicate that reducing excess air by half can reduce NOx emissions by about 15 percent. This control is applicable to wet- and dry-process kilns, as well as those with preheaters or precalciners.	
Cement Manufacturing - Dry Process	Selective Non-Catalytic Reduction - Ammonia	50	This control is the reduction of NOx emission through ammonia based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). This control applies to dry-process cement manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994h
Cement Manufacturing - Dry Process	Selective Non-Catalytic Reduction – Urea	50	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). This control applies to dry-process cement manufacturing with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 1994h
Cement Manufacturing - Dry Process or Wet Process	Low NOx Burner	25	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of	EPA 2006b, EPA 1998e, EPA 2002a, EPA 1994h, EC/R 2000

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			one combustion zone and reducing the amount of oxygen available in another. This control applies to dry-process or wet-process cement manufacturing operations with indirect-fired kilns with uncontrolled NOx emissions greater than 10 tons per year.	
Cement Manufacturing - Dry Process or Wet Process	Mid-Kiln Firing	30	This control is the use of mid-kiln firing to reduce NOx emissions. Mid-kiln firing is the injection of solid fuel into the calcining zone of a long kiln. This allows for part of the fuel to be burned at a lower temperature, reducing NOx formation. This control applies to wet-process and dry-process cement manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 1994h, EC/R 2000
Cement Manufacturing - Wet Process	Selective Catalytic Reduction	90	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to wet-process cement manufacturing with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2007b

Reproduced from EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022).

State RACT Rules

EPA reviewed information provided in a SIP submission from the Texas Commission on Environmental Quality (TCEQ) concerning NOx control technologies that have been implemented at portland cement plants.[29]

- Texas, Ellis County -Three companies currently operate four kilns in Midlothian, Ellis County. Since 2015, no cement plant is using wet kilns.

- Ash Grove Cement Company (Ash Grove) operated three kilns in Ellis County. However, a 2013 consent decree with EPA required by September 10, 2014 shutdown of two kilns and reconstruction of kiln #3 with SNCR with an emission limit of 1.5 pounds of NOx per ton of clinker and a 12-month rolling tonnage limit for NOx of 975 tpy. The reconstructed kiln is a dry kiln with year-round SNCR operation and is subject to the 1.5 lb NOx/ton of clinker emission standards in the NSPS for Portland Cement Plants. EPA has delegated authority to enforce this NSPS to the TCEQ and the NSPS satisfies RACT for Ash Grove.[30]

- Holcim U.S., Inc. (formerly Holnam) currently has two dry preheater/precalciner (PH/PC) kilns equipped with SNCR. On January 14, 2009, EPA approved the current source cap of 5.3 tons per day (tpd) NOx for Holcim at 30 TAC §117.3123 as satisfying RACT for 1997 8-hours ozone NAAQS.[31]

- Texas Industries, Inc. (TXI) currently operates one dry (PH/PC) kiln #5. The permitted capacity of this kiln is 2,800,000 tons of clinker per year, and it has a permitted emissions factor of 1.95 lb NOx/ton of clinker. Based on these permit limits, this kiln is therefore limited to a maximum of 7.48 tpd NOx, compared to the current 30 TAC §117.3123 source cap of 7.9 tpd NOx. Kiln #5 typically operates well below the source cap, at an average emission factor below 1.5 lb NOx/ton of clinker. EPA approved this limit as RACT on February 22, 2019 (84 FR 5601). The current NOx Source Cap (tpd) for Ellis County cement plants is shown below.

Table 3.D: NOX Source Cap for Ellis County Cement Plant

Cement Plant	NOx Cap - tpd
Ash Grove	4.4
Holcim	5.3
TXI	7.9
Total	17.6

[29] See TCEQ, Appendix F, Reasonably Available Control Technology Analysis, Dallas-Fort Worth Serious Classification Attainment Demonstration SIP Revision, TCEQ Project Number 2019-078-SIP-NR, available at https://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/dfw_ad_sip_2019/DFWAD_19078SIP_Appendix_F_pro.pdf (URL dated October 12, 2021).
[30] Delegation Documents for State of Texas, see https://www.epa.gov/tx/region-6-delegation-documents-state-texas-0.
[31] January 14, 2009 (74 FR 1927).

Emission Limits and Compliance Requirements in the Final Rule

In setting the emission limits for long wet kilns, EPA considered a range of emission limits from 3.88 to 6.0 lb/ton of clinker produced. EPA reviewed a 2008 ozone NAAQS RACT standard of 3.88 limit. *See* 25 Pa. Code 129.97 (h)(1). EPA initially approved a NOx emissions limit of 4.0 lb/ton of clinker (Texas Administrative Code (TAC), title 30, chapter 117, section 117.265), under the 1-hour ozone NAAQS, for long wet kilns in Ellis County, Texas. *See* Table III, entry for long wet kiln in Ellis County, at (69 FR 15685, March 26, 2004). This limit was later reaffirmed by approving 30 TAC section 117.3110(a)(1)(B), . *See* 74 FR 1927 (January 14, 2009). Also, *see* Chapter V of the TSD for the 2009 approval rulemaking action made available in docket. It is evident and has been shown in practice that a NOx emissions limit of 4.0 using is achievable using a post combustion control device like SNCR. The final rule establishes an emissions limit of 4.0 lb/ton clinker for long wet kilns (as we had proposed).

For setting emission limits for long dry kilns, EPA reviewed the consent agreement and final order (CAFO) for Docket No. CAA-01-2013-0053 issued to Dragon Products Company, in Maine; LaFarge Building Materials – Ravena Cement Plant of New York [subject to NSPS, 40 CFR 60.62(a)]; Hercules Cement Company LP/Stockertown in Pennsylvania [subject to 25 Pa Code §129.97(h)(2), 2008 Ozone RACT]; and Holcim US, Inc – Joppa Plan in Illinois [subject to 35 IAC 217.224(a), 2008 Ozone RACT]. These plants are assigned NOx emissions limit of 2.33, 1.5, 3.44, and 5.1 lbs/ton of clinker, respectively, averaging an emissions limit of 3.1. EPA also reviewed a NOX emission limit of 5.1 lbs/ton of clinker (69 FR 15681; March 26, 2004). We also reviewed the EPA-approved Texas SIP limit at 30 TAC 117.3110(a)(2), which is 5.1 lbs/ton of clinker. We note that the LaFarge cement plant in New York, is required to comply with a limit of 1.5 lbs/ton of clinker. For the Joppa Illinois plant, air permit 9509119 – at section 8.2 subpart H identifies a limit of 5.1 lbs/ton of clinker for kiln #2. Kiln #2 (J-47) is not equipped with post-combustion controls such as SNCR. Several data in our review showed 5.1 lbs/ton of clinker to be a typical limit when a source operates without SNCR. The ERG cement study comparing common post combustion NOx abatement technologies for NOx emissions control has shown that SNCR in practice is capable of achieving NOx reduction of 40-71 percent.[32] Taking the largest emission limit of 5.1 lbs/ton of clinker from the above list and applying a conservative (the lower end of the achieved NOx emissions reduction range) control efficiency of 41% reduction through use of SNCR as control device ((5.1-3.0)/(5.1) x 100 = 41) would result in an emission limit of 3.0 lb/ton. The final rule establishes an emissions limit of 3.0 lb/ton clinker for long dry kilns (as we had proposed).

For setting emission limits for pre-calciner kilns, EPA reviewed a 2008 ozone NAAQS RACT standard, Regulation 19, Rule 13, Section 301.1, Bay Area Air Quality Management District (BAAQMD). This rule establishes a limit of 2.3 lbs/ton of clinker. EPA reviewed BAAQMD Lehigh Southwest Cement Company air permit #A0017. Section III, Table II B - Abatement Devices of said permit sets forth a limit of 2.3 lbs/ton of clinker. EPA also reviewed a

[32] ERG, Inc, Final Report, July 14, 2006, (TCEQ Contract No. 582-04-65589 Work Order No.05-06), ASSESSMENT OF NOx EMISSIONS REDUCTION STRATEGIES FOR CEMENT KILNS - ELLIS COUNTY, Table 4-3.1, page 4-47. Also, see https://www.tceq.texas.gov/airquality/stationary-rules/BSA_settle.html (URL dated February 28, 2023).

consent decree in civil action No. 09-cv-0019-MSK-MEH (D. Colo.) entered with Cemex Construction Materials South LLC – Lyons Cement Plant of Colorado. The CD requires a limit of 1.85 to 3.11 lbs/ton of clinker, with SNCR as the control device. *See also* Colorado Department of Public Health Operating Permit 95OPBO082. Based on the range of emissions limit identified in the agreement above, permit #A0017, and BAAQMD Rule 13, Section 301.1, the final rule establishes an emissions limit of 2.3 lb/ton clinker for pre-calciner kilns (as we had proposed).

For setting emission limits for preheaters, EPA based the emission limit of 3.8 lb/ton on EPA-approved Texas and Illinois standards. *See, e.g.*, Appendix F, Reasonably Available Control Technology Analysis, https://www.tceq.texas.gov/assets/public/implementation/air/sip/dfw/dfw_ad_sip_2019/DFWAD_19078SIP_Appendix_F_pro.pdf (URL dated October 12, 2021); Illinois 35 IAC 217.224(a). Also *see* Table III at (69 FR 15681, March 26, 2004). The final rule establishes an emissions limit of 3.8 lb/ton clinker for preheater kilns (as we had proposed).

For setting emission limits for preheater/precalciner kilns, EPA reviewed a 2008 ozone NAAQS RACT standard, Pennsylvania Rule 25 Pa Code §129.97(h)(3). This rule establishes a limit of 2.36 lbs/ton of clinker. EPA reviewed Illinois Rule 35 IAC 217.224(a). This rule establishes a limit of 2.8 lbs/ton of clinker. EPA also reviewed California Rule 1161(C)(2).This rule establishes a limit of 2.8 lbs/ton of clinker. See MDAQMD Federal Operating Permit # 100005 permits for CEMEX Construction Materials Pacific - Victorville and Apple Valley, Permit Number: 11800001 MDAQMD Federal Operating Permit Mitsubishi Cement Corporation. EPA also reviewed January 14, 2009 (74 FR 1927), Docket ID No. EPA-R06-OAR-2007-1147; and January 14, 2009 (74 FR 1903), Docket ID No. EPA-R06-OAR-2007-0524 establishing a limit of 2.8 lbs/ton of clinker. Both dockets are available at www.regulations.gov. See also 30 TAC 117.3110(a)(4). Based on above information, the final rule establishes an emissions limit of 2.8 lb/ton clinker for preheater kilns (as we had proposed).

Generally, the emission limits in the final rule can be met through installation and operation of SNCR on all types of cement kilns covered by the final rule.

Performance Tests and Monitoring

In the final rule, EPA is requiring that performance tests be conducted on annual basis and in accordance with the applicable reference test methods in 40 CFR part 60, any alternative test method approved by EPA as of the effective date of the final rule, or other methods and procedures approved by EPA through notice-and-comment rulemaking.

EPA solicited comment on whether it was feasible or appropriate to require affected units (kilns) to be equipped with continuous emission monitoring systems (CEMS) to measure and monitor the NOx concentration (emissions level) instead of conducting performance tests on a semiannual basis (as we had proposed).

In response to comments received, EPA has established provisions in the final rule allowing affected units in this industry that operate NOx CEMS meeting specified requirements to use CEMS data in lieu of performance tests and parametric monitoring to demonstrate compliance. For affected units that do not operate a NOx CEMS, the final rule requires owners and operators to conduct an initial performance test before the 2026 ozone season to establish appropriate ranges for operating parameters and to subsequently conduct annual NOx performance tests. The final rule also requires owners and operators to monitor and record kiln stack exhaust gas flow rate, hourly clinker production rate or kiln feed rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests, and to continuously monitor and record those parameters to demonstrate continuous compliance with the NOx emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance tests do not have to be conducted during the ozone season.

Owners and operators of affected units must also reassess and adjust the site-specific operating parameters in accordance with the results of each performance test, and report and include ongoing site-specific operating parameter data in the annual reports to EPA and the semi-annual title V monitoring reports to the relevant air permitting authority.

4 Iron and Steel Mills and Ferroalloy Manufacturing+

Background

The steel and iron making processes are iterative processes during which iron is first produced and then further refined to steel. The most common furnace types used for iron and steel production are blast furnaces, basic oxygen process furnaces (BOF), electric arc furnaces (EAF), annealing furnaces, ladle metallurgy furnaces (LMF), and reheat furnaces.

NOx emissions from iron and steel production are most often thermal NOx from the combustion of fossil fuels and other raw materials in furnaces or ancillary processes. The mixture of air and fuel in the furnace react to form NOx. Fuel and prompt NOx are also generated through oxidation of nitrogen compounds within the fossil fuels and the oxidation of hydrogen cyanide (HCN), respectively.

Detailed information describing iron and steel production was included in the TSD supporting the proposal.[33] This information included details related to the iron making process, the steel production process, and the ferroalloy manufacturing process; federal and state regulations that apply to facilities with these processes; and available NOx control technologies. This can be found in Section 4 of the TSD to the proposal and is not repeated here.

Emissions Limits and Compliance Requirements in the Final Rule

Summary of Proposed Requirements

EPA proposed to establish emissions control requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category for emission units that directly emit or have the potential to emit 100 tpy or more of NOx and for facilities containing two or more such units that

[33] See Document ID Number EPA-HQ-OAR-2021-0668-0145.

collectively emit or have the potential to emit 100 tpy or more of NOx. EPA proposed NOx emissions standards based on relevant available information for the source category, 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. A summary of the proposed standards was provided in Table VII.C-3 of the preamble to the proposed rule (87 FR 20145).

Based on the use of low-NOx emissions technology such as SCR, SNCR, flue gas recirculation (FGR), newer generation LNB, or optimization of existing LNB, EPA proposed NOx emissions limits for the following types of units for affected facilities in the iron and steel and ferroalloy manufacturing industry:

- Blast furnaces,
- Basic oxygen furnaces,
- Electric arc furnaces,
- Ladle/tundish preheaters,
- Reheat furnaces,
- Annealing furnaces,
- Vacuum degassers,
- Ladle metallurgy furnaces,
- Taconite production kilns,
- Coke ovens (charging and pushing), and
- Boilers (coal, residual oil, distillate oil, and natural gas).
-

Summary of Final Rule Requirements

EPA received comments from a number of different stakeholders, including trade organizations, industry, and state environmental agencies, who argued that EPA had not provided sufficient information to demonstrate the feasibility of controls on which the proposed NOx emissions limits were based. In response to these comments, EPA conducted additional evaluations, including a re-evaluation of the emissions controls that are feasible for all types of furnaces. The data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NOx controls, including SCR or other NOx control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry. Based on these additional evaluations, EPA has decided not to finalize the proposed emission limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces (EAFs) at this time.

EPA is finalizing emissions control requirements for reheat furnaces that directly emit or have the potential to emit 100 tpy or more of NOx. EPA is also finalizing a revised definition for reheat furnaces to include all furnaces used to heat steel product, including metal ingots, billets, slabs, beams, blooms and other similar products, to temperatures at which it will be suitable for deformation and further processing. There are several types of reheat furnaces, including those that operate with a continuous feed of material and those that operate with batches of feed material. Of the continuous feed type, reheat furnaces can be further classified as pusher, rotary hearth, walking beam, walking hearth, or roller hearth type. Information reviewed post-proposal indicates that LNB are feasible for all types of reheat furnaces. Through review of facility operating permits, EPA found that LNB is required for reheat furnaces producing a variety of steel products including bar, rolled coil, and plate steel. Therefore, for Iron and Steel and Ferroalloy manufacturing, EPA is finalizing requirements for reheat furnaces that will require the use of low-NO_X burners (LNB) or equivalent low-NO_X technology that achieves at least a 40% reduction from baseline NO_X emissions. We provide additional discussion below under the heading *Controls on Reheat Furnaces*.

Controls on Blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

Many comments on the proposed rule stated that EPA did not sufficiently demonstrate that the proposed standards were technologically feasible for iron and steel emission units of these types and that the record is insufficient and does not support establishing NOx emission control requirements. Several commenters urged EPA not to finalize emissions standards for iron and steel emissions units such as blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and EAFs. Commenters explained that the NOx standards as proposed should not be included in the final rule for several reasons, including complications related to the uniqueness of each emissions unit, various design-related challenges, and expected impracticality of implementation of add-on NOx control technology. Furthermore, commenters stated that SCR had not been applied for reasonably available control technology (RACT), best available control technology (BACT), or lowest available emissions rate (LAER) purposes on iron and steel units.

In the preamble to the proposed rule, EPA indicated that it assumed that these source types (excluding taconite kilns) could meet the proposed emission limits through the application of SCR and/or SNCR. Commenters expressed concern about requirements to install SCR control on the units for which EPA proposed emissions limits. According to several commenters, EPA did not conduct a complete technical evaluation to determine that SCR is feasible. The commenters stated that iron and steel units had not installed SCR except in a few rare instances for experimental reasons and that SCR technology was not readily available or known for the iron and steel industry. One industry commenter in particular (United States Steel Corporation (U.S. Steel))[34] noted that SCR is not feasible for the emissions units EPA proposed to regulate. To elaborate on that point, the commenter (U.S. Steel) indicated that installing SCR control on some of the emission units at U.S. Steel's integrated iron and steel facilities would require significant preconditioning and heating of the exhaust gas to make it amenable to SCR. According to the commenter, this process would be difficult to design and operate, and would also require increased use of natural gas, which would result in other impacts and costs not considered by EPA.

Similarly, comments received from the Mississippi Department of Environmental Quality (MDEQ) on the proposed requirements expressed that EPA should not assume NOx control is achievable for all units in the source category. The commenter stated that EPA did not fully evaluate the applicability of NOx control across all sources and only evaluated a handful of Iron and Steel Mills and Ferroalloy Manufacturing emission units. Comments from MDEQ critiqued

[34] See Document ID Number EPA-HQ-OAR-2021-0668-0798.

EPA's use of a limited number of facilities and units modeled for the proposed rule, and the proposed extension of the calculated limits to all units in the source category. In terms of SCR feasibility specifically, MDEQ stated that "[s]ome of the furnaces and heaters are not even equipped with adequate stacks to support add-on controls and stack gas would have to be reheated to route it through an SCR." These comments were echoed by the West Virginia Department of Environmental Protection (WV DEP)[35] who stated that the proposal lacks technical basis.

Comments from owners of two ferroalloy manufacturing plants (Felman Production (Felman) and CC Metals and Alloys (CCMA)) who use EAFs in their production processes stated that EPA had not assessed the viability of controls of EAFs in this industry. Felman and CCMA noted a number of unique concerns regarding the applicability of controls to EAFs in ferroalloy production. The commenters also claim that EPA had not provided evidence in the record supporting controls on any EAFs.[36]

Nucor Corporation (Nucor)[37] also stated that the proposed NOx limits are not technically or economically feasible. Consistent with remarks from other commenters, Nucor stated that EPA had not provided an adequate basis in the record to support the proposed emissions limits for EAFs.

In response to the comments EPA received concerning NOx controls for iron and steel emission units, EPA reviewed multiple permits to determine which, if any NOx controls are being used in the industry. EPA reviewed more than 50 permits across multiple states with varying iron and steel emissions source types. EPA also searched EPA's RACT/BACT/LAER Clearinghouse (RBLC)[38] for additional information on NOx limits and control technologies that may have been applied to sources in this industry as a result of a RACT, BACT, or LAER analysis. These reviews identified three annealing furnaces, two galvanizing furnaces, and one reheat furnace, with combustion or post-combustion controls. These are discussed further in the sections below.

Review of Post-Combustion Controls on Emission Sources Other Than Reheat Furnaces

Annealing Furnaces. Annealing is a heat treatment process used to change the hardness and strength of steel. As shown in Table 4-1, very few of these were found in the RBLC to be employing post-combustion controls. For the U.S. Steel facility, the annealing furnace is part of a continuous galvanizing line where the steel is annealed prior to galvanization (coating with zinc). The PRO TEC facility is part of USS Galvanizing, Inc., and so it is also likely part of a galvanizing process. It is not clear whether annealing furnaces associated with galvanizing processes are inherently different than annealing furnaces serving other types of steel finishing processes (which offer exhaust streams conducive to SCR application). However, based on other

[35] See Document ID Number EPA-HQ-OAR-2021-0668-0359.
[36] See for example Document ID Number EPA-HQ-OAR-2021-0668-0345, page 6.
[37] See Document ID Number EPA-HQ-OAR-2021-0668-0280.
[38] EPA, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse (RBLC), https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.

processes present in the RBLC, the Mount Vernon facility does not appear to conduct galvanizing, and it has SCR installed.

Table 4.A: Annealing Furnace Post-Combustion NOx Controls

Process	Capacity (MMBtu/hr)	Control(s)	NOx Limit	State	Facility
Annealing	N/A	SCR	6.6 lb/hr	MI	US Steel Great Lakes Works
Annealing	120	ULNB, SCR	0.06 lb/MMBtu	AL	MOUNT VERNON MILL
Annealing	77	SCR	0.06 lb/MMBtu	OH	PRO TEC COATING COMPANY

Source: EPA RBLC.

Other Sources. Another source type identified with post-combustion NOx controls applied are galvanizing line furnaces. These furnaces are used to heat the molten bath of zinc into which the steel part is dipped for galvanization. These sources are listed in Table 4.B. Information for the Nucor Steel facility comes from the permit documentation above, while the other example for Big River Steel comes from the RBLC (in this case, the actual process is inferred from all of the processes listed for the facility).

Table 4.B: Post-Combustion NOx Controls on Other Iron and Steel Source Types

Process	Capacity (MMBtu/hr)	Control(s)	NOx Limit (lb/MMBtu)	State	Facility
Furnace, Galvanizing Line	128	SCR/SNCR	0.0075	AR	NUCOR STEEL ARKANSAS
Furnace, Galvanizing Line	151	SCR	0.035	AR	BIG RIVER STEEL LLC

After review and consideration of public comments on the proposal and the review of iron and steel and ferroalloy manufacturing operating permits and the RBLC, EPA recognizes and agrees with concerns associated with whether the feasibility and cost-effectiveness of installation and operation of NOx controls at iron and steel mills and ferroalloy manufacturing facilities has been adequately demonstrated in the present record on a fleetwide basis across the covered states and is not finalizing the ten proposed emissions limits that would necessitate the use of SCR at certain facilities.

Based on the above, EPA is not finalizing the proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

EPA is aware of many examples of low-NOx technology utilized at furnaces, kilns, and other emissions units in other sectors with similar stoichiometry, including taconite kilns, blast furnace stoves, electric arc furnaces (oxy-fuel burners), and many other examples at refineries and other large industrial facilities. EPA anticipates that with adequate time, modeling, and optimization efforts, such NOx reduction technology may become achievable and cost-effective for these particular types of emissions units. However, EPA is not finalizing regulatory requirements for these emissions units at this time. Reheat furnaces and boilers (discussed in Section 6 of this document) are the only type of emissions unit within the Iron and Steel Mills and Ferroalloy Manufacturing industry that this final rule applies to and are discussed in more detail in the section below.

Controls on Reheat Furnaces

EPA has determined that combustion controls are technically feasible and cost-effective for reheat furnaces in the iron and steel industry. Reheat furnaces are used at both integrated iron and steel facilities as well as steel mini-mills (*i.e.,* EAF mills). They are used to reheat semi-finished steel in the form of ingots, billets or slabs, so that the steel can be further processed (*e.g.,* rolled) into finished products.

EPA performed a review of state permits and EPA's RBLC[39] to identify controls that are currently in place for reheat furnaces. This review identified 32 reheat furnaces that have an associated combustion control to reduce NOx emissions. The controlled furnaces range in size from 38 to 720 MMBtu/hr. Most of these units are controlled using LNB. However, five units are controlled with ultra-low NOx burners (ULNB), three use LNB plus FGR, and one furnace was found with LNB and SCR controls. (See the discussion below on the issues encountered by the latter furnace with SCR.)

Based on the current set of identified reheat furnaces with combustion controls, this final rule requires installation of these controls or equivalent low-NO_X technology on a range of reheat furnace types. Table 4-3 summarizes the types of controlled reheat furnaces identified, the range of corresponding NOx emission limits, furnace capacity, and controls applied. Note that not all reheat furnaces were identified by type in the permits or the RBLC, and these are listed simply as reheat furnaces in Table 4-3. Also, some emission limits were not specified in units of lb/MMBtu, so these are listed as N/A (not available).

Table 4.C: Controlled Reheat Furnaces

Furnace Type	Count	NOx Limit (lb/MMBtu)	Capacity (MMBtu/hr)	Controls Applied
bar mill	1	0.13	228	LNB
Billet	7	0.073-0.10	77-350	LNB, LNB+FGR, ULNB
hot strip mill	3	0.35	630	LNB
reheat furnace	10	0.070-0.17	38-450	LNB, LNB+FGR, ULNB
Rotary	1	N/A	N/A	LNB
Slab	3	0.077-0.10	265-500	LNB, LNB+SCR
tunnel	2	0.1	103-150	LNB
walking beam	5	0.07-0.35	261-720	LNB, ULNB

Source: State permits and EPA RBLC.

[39] EPA, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse (RBLC), https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.

The furnace identified with SCR was the only reheat furnace that EPA found to have post-combustion controls. This reheat furnace is at an NLMK facility in Indiana (formerly Beta Steel). Some additional information regarding the NOx controls at this furnace was obtained from the Indiana Department of Environmental Management (IDEM).[40] This included a BACT determination from 2003 which indicated that the reheat furnace was initially installed in the early 1990's with LNB and SCR. The original NOx emissions limit was set to 0.014 lb/MMBtu; however, testing in the late-1990's indicated that the facility could not meet that limit. The facility requested that the limit be raised to be closer to other RBLC entries, which as indicated in Table 4-3, were being met with LNB/ULNB in many cases. In their request, NLMK indicated that the exhaust conditions were too variable for optimal SCR operation. In particular, temperature and particulate matter concentrations vary depending on the material being heated. The IDEM relaxed the emissions requirement (0.077 lb/MMBtu) for the unit based on the highest emission rate of three previous stack tests.

As stated above, EPA has determined that combustion controls are feasible and cost-effective for reheat furnaces. This determination is supported by the information in the preceding section regarding the range of reheat furnace types and sizes that have successfully applied combustion controls. EPA is finalizing a test-and-set requirement for reheat furnaces that requires the installation of LNB or equivalent low-NOx technology on units emitting more than 100 tons of NOx per year to reduce NOx emissions by 40% from baseline levels.

Compliance Requirements in the Final Rule

Performance Tests and Monitoring

EPA proposed to require each owner or operator of an affected unit subject to the NOx emissions limit for Iron and Steel Mills and Ferroalloy Manufacturing emissions units to install, calibrate, maintain, and operate a CEMS for the measurement of NOx emissions. EPA proposed that each emissions unit had to conduct an initial performance test and to operate CEMS to assure compliance.

Commenters stated concerns with the proposed CEMS requirements for a variety of reasons. One key concern expressed by commenters was the cost of installing, operating, and maintaining the CEMS unit, in particular for smaller units with lower emissions. Echoing similar comments related to the CEMS requirement, one commenter (Felman and CCMA) who produces ferroalloys asked that EPA not finalize this monitoring requirement for ferroalloy operations. The commenter stated that "[t]he complex ductwork, high flowrates and temperatures, and significant levels of dust associated with ferroalloy manufacturing makes CEMS technically complex and more likely to operate unreliably."[41] This commenter stated that in EPA's final rulemaking for the Ferroalloy NESHAP RTR, EPA decided to amend the baghouse monitoring requirements to allow visible emissions monitoring instead.[42]

[40] S. Roe, SC&A, personal communication with B. Farrar, IDEM, 1/10/2023.
[41] See Document ID Number EPA-HQ-OAR-2021-0668-0345, page 6.
[42] See 82 FR 5403.

One commenter (Nucor)[43] claimed EPA had not provided a basis for requiring CEMS and that it is a burdensome monitoring requirement that is technically and economically infeasible. The commenter stated that for most ladle and tundish preheaters, bell annealing furnaces, and mobile reheat furnaces, which do not have existing ductwork, there is no practical way to install CEMS. According to Nucor, there are other simpler compliance assurance measures that are less onerous and sufficient to ensure ongoing compliance.

Other commenters described complexities in using a CEMS to monitor NOx emissions on mobile reheat surfaces, stated that the unique configuration of certain facilities would render it impossible for a CEMS to differentiate emissions from a reheat furnace and other units, like waste heat boilers, and recommended that in place of CEMS, EPA could allow for CEMS or performance testing and recordkeeping.

Of the reheat furnace permits reviewed, one facility was found to be required to monitor NOx emissions via a CEMS. Compliance for most of the other controlled reheat furnaces was typically specified as periodic testing or simply through monitoring and reporting of fuel usage to ensure that the maximum allowed fuel usage is not exceeded.

The final rule for iron and steel reheat furnaces allows compliance to be demonstrated through CEMS or via annual performance tests and continuous parametric monitoring to determine compliance with the 30-day rolling average emissions limit during the ozone season. Affected units subject to this rule that operate NOx CEMS meeting specified requirements may use CEMS data in lieu of performance tests and continuous parametric monitoring to demonstrate compliance. For affected units that do not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NOx emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance test does not have to be performed during ozone season. Owners and operators of affected units must also reassess and adjust the site-specific operating parameters in accordance with the results of each performance test, and report and include ongoing site-specific operating parameter data in the annual reports to EPA and the semi-annual title V monitoring reports to the relevant air permitting authority.

[43] See Document ID Number EPA-HQ-OAR-2021-0668-0280.

5 Glass and Glass Product Manufacturing

Process Description[44]

Glass melting furnaces are used by the glass industry in the production of glass. The glass melting furnaces contribute to most of the total emissions from the glass plant. Essentially all of the Oxides of Nitrogen (NOx) emissions associated with glass manufacturing are generated in the melting furnaces due to the high process temperatures. Nitrogen oxides form when nitrogen and oxygen react in the high temperatures of the furnace.

Detailed information describing glass production can be found in Section 5 of the TSD to the proposal and is not repeated here.

Federal Rules affecting Glass Plants

Glass plants are subject to the Glass Manufacturing NESHAP (40 CFR Part 63, subpart SSSSSS) and NSPS (40 CFR part 60, subpart CC). Glass manufacturing facilities that are designated as an area source of hazardous air pollutants (HAP) emissions are subject to the Glass Manufacturing Area Source NESHAP (40 CFR part 63, subpart SSSSSS).

The NSPS implementing CAA section 111(b) for Glass Manufacturing Plants was first promulgated at 40 CFR part 60, subpart CC on October 7, 1980 (45 FR 66751). EPA conducted three additional reviews of these standards on October 19, 1984 (49 FR 41030), February 14, 1989 (54 FR 6674), and October 17, 2000 (65 FR 61759). The NSPS applicable to the glass manufacturing industry only provides standards for particulate matter from sources and does not provide standards or averaging times for NOx.

NOx Controls

The NACAA (formerly STAPPA/ALAPCO) has recommended requiring "combustion modifications, process changes and post-combustion controls [Selective Non-Catalytic Reduction] (SNCR)" to limit NOx emissions from the glass furnaces source category.[45] SNCR is a post combustion control technology used to reduce NOx emissions without the presence of a catalyst. The NACAA has also noted that "RACT limits of 5.3-5.5 lbs NOx/ton of glass removed have been adopted, as well as limits as low as 4.0 lbs NOx/ton of glass removed" and recommended "[requiring] sources to coordinate installation of controls with routine furnace rebuilds to lower costs."[46]

The European Union Commission charged with establishing the BAT to control NOx emissions from the production of glass outlines the control techniques shown below in Table 5.A below.

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[44] See generally EPA, AP-42 Compilation of Air Emissions Factors, Mineral Products Industry, Chapter 11, Mineral Products Industry, Section 11.15, Glass Manufacturing, Final Section (October 1986, reformatted January 1995).
45 STAPPA/ALAPCO, Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options, 78-79 (July 1994), available at https://p2infohouse.org/ref/02/01245/3017101.pdf.
[46] Id.

Table 5.A: European Union Commission NO_X BAT Controls.

Primary Techniques/Measures	**Description**
Combustion Modifications	
(i) Reduction of air/fuel ratio	The technique is mainly based on the following features: - minimization of air leakages into the furnace - careful control of air used for combustion - modified design of the furnace combustion chamber
(ii) Reduced combustion air temperature	The use of recuperative furnaces, in place of regenerative furnaces, results in a reduced air preheat temperature and, consequently, a lower flame temperature. However, this is associated with a lower furnace efficiency (lower specific pull), lower fuel efficiency and higher fuel demand, resulting in potentially higher emissions (kg/ton of glass)
(iii) Staged combustion	- Air staging – involves sub-stoichiometric firing and the addition of the remaining air or oxygen into the furnace to complete combustion. - Fuel staging – a low impulse primary flame is developed in the port neck (10 % of total energy); a secondary flame covers the root of the primary flame reducing its core temperature
(iv) Flue-gas recirculation	Implies the reinjection of waste gas from the furnace into the flame to reduce the oxygen content and therefore the temperature of the flame. The use of special burners is based on internal recirculation of combustion gases which cool the root of the flames and reduce the oxygen content in the hottest part of the flames
(v) Low-NOx burners	The technique is based on the principles of reducing peak flame temperatures, delaying but completing the combustion and increasing the heat transfer (increased emissivity of the flame). It may be associated with a modified design of the furnace combustion chamber
(vi) Fuel choice	In general, oil-fired furnaces show lower NOx emissions than gas-fired furnaces due to better thermal emissivity and lower flame temperatures
Special furnace design	Recuperative type furnace that integrates various features, allowing for lower flame temperatures. The main features are: - specific type of burners (number and positioning) - modified geometry of the furnace (height and size) - two-stage raw material preheating with waste gases passing over the raw materials entering the furnace and an external cullet preheater downstream of the recuperator used for preheating the combustion air

Electric melting	The technique consists of a melting furnace where the energy is provided by resistive heating. The main features are: - electrodes are generally inserted at the bottom of the furnace (cold-top) - nitrates are often required in the batch composition of cold-top electric furnaces to provide the necessary oxidizing conditions for a stable, safe and efficient manufacturing process
Oxy-fuel melting	The technique involves the replacement of the combustion air with oxygen (>90% purity), with consequent elimination/reduction of thermal NOx formation from nitrogen entering the furnace. The residual nitrogen content in the furnace depends on the purity of the oxygen supplied, on the quality of the fuel (% N2 in natural gas) and on the potential air inlet
Chemical reduction by fuel	The technique is based on the injection of fossil fuel to the waste gas with chemical reduction of NOx to N2 through a series of reactions. In the 3R process (which is proprietary), the fuel (natural gas or oil) is injected at the regenerator entrance. The technology is designed for use in regenerative furnaces.
Selective catalytic reduction (SCR)	The technique is based on the reduction of NOx to nitrogen in a catalytic bed by reaction with ammonia (in general aqueous solution) at an optimum operating temperature of around 300 – 450 °C. One or two layers of catalyst may be applied. A higher NOX reduction is achieved with the use of higher amounts of catalyst (two layers)
Selective non-catalytic reduction (SNCR)	The technique is based on the reduction of NOx to nitrogen by reaction with ammonia or urea at a high temperature. The operating temperature window must be maintained between 900 and 1,050 °C
Minimizing the use of nitrates in the batch formulation	The minimization of nitrates is used to reduce NOx emissions deriving from the decomposition of these raw materials when applied as an oxidizing agent for very high quality products where a very colourless (clear) glass is required or for other glasses to provide the required characteristics. The following options may be applied: - Reduce the presence of nitrates in the batch formulation to the minimum commensurate with the product and melting requirements. - Substitute nitrates with alternative materials. Effective alternatives are sulphates, arsenic oxides, cerium oxide. - Apply process modifications (e.g. special oxidizing combustion conditions)

Reproduced from Official Journal of European Union Commission, Best Available Techniques (BAT) Conclusions Under Directive 2010/75/EU of the European Parliament and of the Council on Industrial Emissions for the Manufacture of Glass, February 28, 2012, Table 1.10.2.

EPA's Menu of Control Measures (MCM) provides state, local and tribal air agencies with information on existing criteria pollutant emission reduction measures as well as relevant information concerning the efficiency and cost effectiveness of the measures. State, local, and tribal agencies may use this information in developing emission reduction strategies, plans and programs to assure they attain and maintain the NAAQS. The information from the MCM can also be found in the Control Measures Database (CMDB), a major input to the Control Strategy Tool (CoST), which EPA used in the NOx control strategy analysis included in the Non-EGU Screening Assessment memorandum.[47] Information about control measures to reduce NOx emissions from glass manufacturing operations is shown in Table 5.B below.

[47] EPA, Control Measures Database (CMDB) for Stationary Sources, available at https://www.epa.gov/system/files/other-files/2021-09/cmdb_2021-09-02_0.zip (URL dated January 6, 2022).

Table 5.B: List of NO_X Controls Available for Glass Manufacturing Furnaces

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Glass Manufacturing - Container	Cullet Preheat	25	This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations.	EPA 2006b, EPA 1998e, EPA 1994f
Glass Manufacturing - Container	Electric Boost	10	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations.	EPA 2006b, EPA 1998e, EPA 1994f
Glass Manufacturing - Container	Selective Catalytic Reduction	75	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to glass-container manufacturing processes with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f
Glass Manufacturing - Container	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emissions through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to glass-container manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f, EPA 1993c
Glass Manufacturing – Container or Flat Glass	Low NOx Burner	40	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to flat glass and container glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 1994f

Glass Manufacturing – Flat Glass	Electric Boost	10	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations.	EPA 2006b, EPA 1998e, EPA 1994f
Glass Manufacturing - Flat Glass	Selective Catalytic Reduction	75	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f, EPA 1993c
Glass Manufacturing - Flat	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f, EPA 1993c
Glass Manufacturing – Pressed	Cullet Preheat	25	This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations.	EPA 2006b, EPA 1998e, EPA 1994f
Glass Manufacturing – Pressed	Electric Boost	10	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations.	EPA 2006b, EPA 1998e, EPA 1994f
Glass Manufacturing - General	Low NOx Burner	40	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to pressed glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 1994f
Glass Manufacturing - General	OXY-Firing	85	This control is the use of Oxy-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn	EPA 2006b

			the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing"	
Glass Manufacturing - Pressed	Selective Catalytic Reduction	75	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to pressed-glass manufacturing operations, and uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f, EPA 1993c
Glass Manufacturing - Pressed	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emissions through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to pressed-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994f, EPA 1993c

Reproduced from EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022)

In 1994, the Emission Standards Division of the Office of Air Quality Planning and Standards of the U.S. Environmental Protection Agency issued a report detailing alternative control techniques (ACTs) for NOx emissions from glass manufacturing facilities. The table below summarizes the NOx control technologies identified in EPA's ACT document for glass manufacturing.[48]Since 1994, and at least through 2002, the demand for flat, container, and pressed/blown glass continued to increase annually.[49] To meet this demand, the glass manufacturing industry has also continued to grow. The flat glass industry alone was expected in the early 2000s to continue to grow by 10–20% annually due to the increase of flat glass demands within the building construction and car manufacturing industry. Nitrogen oxides are one of the primary air pollutants produced during the production and manufacturing of glass products. However, current federal NSPS and NESHAP regulations only control emissions of particulate matter, metals, and organic hazardous air pollutants. Currently, there is no NSPS that provides standards for NOx from glass manufacturing furnaces. Since 1994, various studies have been conducted by the glass manufacturing industries to help identify preferred techniques for the control of NOx.

Table 5.C: List of NO_X Controls and Reduction Percentages for Glass Furnaces

Technology	NOx Reduction (%)
Combustion modifications	
Low NOx burners	40
Oxy-firing	85
Process modifications	
Modified furnace	75
Cullet preheat	25
Electric boost	10
Post combustion modifications	
SCR	75
SNCR	40

State RACT Rules

While NSPS and NESHAP emission control regulations for glass manufacturing facilities historically focused on particulate and arsenic emissions, state RACT rules have set standards for the control of NOx emissions from glass furnaces. EPA reviewed various RACT NOx rules from states located within the Ozone Transport Region (OTR). EPA chose to review these RACT NOx rules because several OTR states implement Ozone Transport Commission (OTC) model rules and recommendations. EPA also reviewed RACT NOx rules for glass manufacturing in the San Joaquin Valley air quality district in California. During its review, EPA observed that most of the states within the OTR have adopted RACT regulations for the glass manufacturing sector that do not themselves establish the required NOx limits but require a case-by-case evaluation.

[48] EPA, Alternative Control Techniques Document— NOx Emissions from Glass Manufacturing, EPA-453/R-94-037 (June 1994) at 2-7.
[49] U.S. Department of Energy, Glass Industry of the Future – Energy and Environmental Profile of the U.S. Glass Industry, (April 2002), Pages 6 - 9.

EPA focused its review on rules adopted by OTR states that contain RACT NOx limits for glass manufacturing furnaces. EPA reviewed Pennsylvania's RACT rule since it contains RACT NOx limits on a 30-day rolling average for various glass melting furnace types. Pennsylvania's NOx RACT rule requires owners or operators of a glass melting furnace equipped with CEMS to comply with the following emission limits: 4.0 pounds of NOx per ton of glass pulled for container and fiberglass furnaces, 7.0 pounds of NOx per ton of glass pulled for pressed/blown and flat glass furnaces, and 6.0 pounds of NOx per ton of glass pulled from all other glass melting furnaces.[50]

EPA also reviewed New Jersey's RACT rule since it contains a daily averaging period compared to the 30-day averaging period in Pennsylvania's RACT rule. New Jersey's NOx RACT rule requires each owner or operator of a glass manufacturing furnace to comply with the following emission limits: 4.0 pounds of NOx per ton of glass removed for container, pressed/blown, borosilicate, and fiberglass furnaces.[51] Under New Jersey's RACT rule, an owner or operator of a flat glass manufacturing furnace equipped with CEMS shall not emit more than 9.2 pounds of NOx per ton of glass removed each calendar day during the ozone season.[52] New Jersey's RACT rule also incorporates OTC model recommendations.[53]

Maryland's RACT rule requires owners or operators to optimize combustion by performing daily oxygen tests and maintain excess oxygen at 4.5% or less.[54] The San Joaquin Valley air district in California has adopted RACT NOx emission limits that are based on both 30-day rolling and daily averages.[55]

The following table displays the San Joaquin Valley air district's emission limits for container glass, fiberglass, and flat glass melting furnaces.[56] Owners or operators of container glass/fiberglass furnaces applicable to San Joaquin Valley air district's emission limits detailed in the table below were required to be in full compliance with the Tier 3 NOx limits by January 1, 2014. Meanwhile, owners or operators of flat glass furnaces were required to be in full

[50] Title 25, Part I, Subpart C, Article III, Section 129.304 of PA's NOx RACT regulation provides emission rates for Glass Manufacturing Furnaces. *See* https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements. Owners or operators subject to PA's glass manufacturing furnace RACT NOx regulation shall demonstrate compliance through continuous emissions monitoring systems (CEMS). PA's rule also allows owners or operators to install or operate, or both, an alternative NOx emission monitoring system or method, approved by writing by the Department or appropriate approved local air pollution control agency.
[51] Title 7, Chapter 27, Subchapter 19 of New Jersey's NOx RACT regulation provides NOx emission rates for Glass Manufacturing Furnaces. *See https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.*
[52] NJAC 7:27-19.15(a) (Procedures and deadlines for demonstrating compliance). For a furnace not equipped with CEMS, compliance must be based upon the average of three one-hour tests, each performed over a consecutive 60-minute period. Id.
[53] Id.
[54] Title 26, Subtitle 11, Chapter 26.11.09 of MD's NOx RACT regulation provides operation standards for Glass Manufacturing Furnaces. *See http://www.dsd.state.md.us/comar/comarhtml/26/26.11.09.08.htm.*
[55] *See* San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces" (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf.*
[56] *See Id.*

compliance with the Tier 3 NOx limits by January 1, 2011, and the Tier 4 NOx limits by January 1, 2014.

Figure 5.D: San Joaquin Valley Air District's NO_X Emission Limits for Glass Furnaces

Type of Glass Produced	Tier 2 NOx limit	Tier 3 NOx limit	Tier 4 NOx limit
Container Glass	4.0 [A]	1.5 [B]	not available
Fiberglass	4.0 [A]	1.3 [A, C] 3.0 [A, D]	not available
Flat Glass Standard Option	9.2 [A] 7.0 [B]	5.5 [A] 5.0 [B]	3.7 [A] 3.2 [B]
Flat Glass Enhanced Option	9.2 [A] 7.0 [B]	5.5 [A] 5.0 [B]	3.4 [A] 2.9 [B]
Flat Glass Early Enhanced Option	9.2 [A] 7.0 [B]	not available	3.4 [A] 2.9 [B]

[A] Block 24-hour average
[B] Rolling 30-day average
[C] Not subject to California Public Resources Code Section 19511
[D] Subject to California Public Resources Code Section 19511

Emission Limits and Compliance Requirements in the Final Rule

Generally, the emission limits in the final rule can be met through installation and operation of low-NOx burners on all glass furnaces covered by the final rule. EPA expects that some units might choose to utilize post-combustion controls as well to meet the emission limits.

In setting the emission limits for the Glass and Glass Product Manufacturing Sector, EPA reviewed RACT NOx rules, air permits, Alternative Control Techniques (ACT), and consent decrees. Based on EPA's review, EPA is finalizing emission limits for this sector that are mostly expressed in terms of mass of pollutant emitted (pounds) per weight of glass removed from the furnace (tons), i.e., pounds of NOx emitted per ton of glass produced (lb/ton). Based on EPA's review, this form of NOx emission limit is effective, practicable, and convenient to record and report to an air agency.

In setting the final NOx emission limit for Container Glass Manufacturing Furnaces, EPA considered a range of emission limits from 1.0 to 5.0 lb/ton of glass produced. In particular, EPA notes that it has approved New Jersey's RACT rule limiting NOx emissions to 4.0 lb/ton of glass removed from the furnace. *See* 83 FR 50506 (October 9, 2018). This emission limit for Container Glass Furnaces in New Jersey's RACT rule is consistent with the NOx limit in Pennsylvania's RACT rule.[57] EPA acknowledges that NOx emissions from some glass manufacturing furnaces

[57] Title 25, Part I, Subpart C, Article III, Section 129.304 of PA's NOx regulation for glass manufacturing furnaces limit NOx emissions to 4.0 pounds of NOx per ton of glass pulled for container glass furnaces. *See https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements*.

are already subject to RACT controls that are more stringent than those that EPA is finalizing in this FIP. During the development of the finalized limits, EPA considered the significant differences that exist in the types, designs, configuration, age, and fuel capabilities among glass furnaces nationwide. EPA finds the final emission limits provide cost-effective emissions reductions while also being responsive to the range of operations and production techniques present currently within the industry.

For Pressed/Blown and Fiberglass Manufacturing Furnaces, EPA considered a range of emission limits from 1.0 – 7.0 lb/ton of glass produced. EPA based the final emission limit of 4.0 lb/ton on EPA-approved New Jersey and Pennsylvania RACT rules for glass melting furnaces. EPA also observed that the 4.0 lb/ton limit was consistent for these types of glass manufacturing furnaces with states located in the OTR. *See* 76 FR 52283 (August 22, 2011).

For Flat Glass Manufacturing Furnaces, EPA considered a range of 5.0 – 9.2 lb/ton of glass produced. EPA is finalizing an emissions limit of 7.0 lb/ton on a 30-day rolling average basis, consistent with the NOx limits in Pennsylvania's RACT rule. EPA had proposed a NOx emissions limit of 9.2 lb/ton on a 30-day rolling average basis but is establishing the final emissions limit at 7.0 lb/ton because that is the emissions limit in the Pennsylvania rule that corresponds to a 30-day averaging period; the 9.2 lb/ton limit in the New Jersey rule corresponds to a daily averaging period. The 7.0 lb/ton limit is generally achievable with low NOx burner combustion controls.

In determining the averaging time for the limits, EPA focused its review on the various RACT NOx rules from states located in the OTR. The OTR states have adopted emission limits with varying averaging times. Based on EPA's review, the OTR states varied between a 30-day rolling average or a daily average.[58] EPA also reviewed RACT NOx regulations for the glass manufacturing sector outside the OTR and observed that 30-day rolling averages and daily averages varied throughout the states.[59] EPA is finalizing a requirement that owners and operators of glass manufacturing furnaces must comply with the final NOx emissions limits on a 30-day rolling average time frame. EPA believes that this averaging timeframe is consistent with

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[58] Pennsylvania's RACT NOx emission limits are based on 30-day rolling average. *See* Title 25, Part I, Subpart C, Article III, Section 129.304, *see https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements.* New Jersey's and Massachusetts' rules contain more stringent daily averages. Title 7, Chapter 27, Subchapter 19 of New Jersey's NOx RACT regulation provides NOx emission rates for Glass Manufacturing Furnaces. *See https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf*. 310 CMR Section 7:19 of Massachusetts regulations provides RACT NOx emission limits for Glass Manufacturing Furnaces. *See https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download*. Title 26, Subtitle 11, Chapter 26.11.09 of Maryland's NOx RACT regulation provides operation standards for Glass Manufacturing Furnaces. *See http://www.dsd.state.md.us/comar/comarhtml/26/26.11.09.08.htm.*

[59] For example, the San Joaquin Valley air district's RACT NOx emission limits are based on both 30-day rolling and daily averages. S*ee* San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces" (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf.* Wisconsin's NOx emission limits are based on a 30-day rolling average. See Wisconsin's Administrative Code NR Section 428.22 (November 29, 2021), available at *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.*

other statewide RACT NOx regulations for this particular sector. A 30-day operating day rolling average strikes a balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operation and production.

EPA received numerous comments from the glass and glass product industry urging EPA to provide additional flexibilities for glass manufacturing furnaces during periods of startup, shutdown, and idling. In response to these comments, EPA is promulgating alternative work practice standards and emissions limits that may apply in lieu of the emissions limits during periods of startup, shutdown, and idling. EPA has modeled the alternative standards that apply during startup, shutdown, and idling conditions to some extent on State RACT alternative requirements identified by commenters.[60]

EPA has identified the following seven criteria for developing and evaluating alternative emissions limits and other requirements applicable during periods of startup and shutdown:[61]

(1) The revision is limited to specific, narrowly defined source categories using specific control strategies (*e.g.,* cogeneration facilities burning natural gas and using selective catalytic reduction);
(2) Use of the control strategy for this source category is technically infeasible during startup or shutdown periods;
(3) The alternative emission limitation requires that the frequency and duration of operation in startup or shutdown mode are minimized to the greatest extent practicable;
(4) As part of its justification for the SIP revision, the state analyzes the potential worst-case emissions that could occur during startup and shutdown based on the applicable alternative emission limitation;
(5) The alternative emission limitation requires that all possible steps are taken to minimize the impact of emissions during startup and shutdown on ambient air quality;
(6) The alternative emission limitation requires that, at all times, the facility is operated in a manner consistent with good practice for minimizing emissions and the source uses best efforts regarding planning, design, and operating procedures; and
(7) The alternative emission limitation requires that the owner or operator's actions during startup and shutdown periods are documented by properly signed, contemporaneous operating logs or other relevant evidence.

We address each of these criteria below.

(1) The revision is limited to specific, narrowly defined source categories using specific control strategies (*e.g.,* cogeneration facilities burning natural gas and using selective catalytic reduction).

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[60] See, e.g., Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305-129.307 (effective June 19, 2010), available at *http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/chap129toc.html&d=reduce* and San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces," sections 5.5 – 5.7 (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf.*
[61] 80 FR 33840, 33912 (June 12, 2015).

The alternative requirements in § 52.44(d)-(f) for startup, shutdown, and idling periods apply to glass melting furnaces using combustion modifications (e.g., low-NO_X burners, flue gas recirculation, or oxy-firing) or post-combustion controls (e.g., SCR or SNCR) to comply with the NO_X emissions limits in this final rule. Periodic startup, shutdown, and idling periods are essential to the proper operation and maintenance of a furnace since these are the only times when furnace operators can conduct maintenance and repairs and install control technologies.

(2) Use of the control strategy for this source category is technically infeasible during startup or shutdown periods.

Generally, combustion modifications, including low-NOx burners and oxy-firing, can be operated even during periods of startup or shutdown, since these types of controls are often integrated into the operation of the furnace unit. However, due to different variations in startup and shutdown procedures in various furnace types, it is generally not possible for furnaces to meet numeric emissions limits expressed as emissions per ton of glass produced during these periods. Since there is no glass being pulled during these periods, it is not possible for furnaces to meet a production-based limit during these periods. Therefore, EPA is finalizing work practice standards that require the operation of controls as soon as technically feasible. Specifically, the alternative requirements in § 52.44(d)-(f) provide that the owner or operator "shall place the emissions control system in operation as soon as technologically feasible during startup to minimize emissions" and similarly "shall operate the emissions control system whenever technologically feasible" during shutdown to minimize emissions, even if these controls do not achieve the same level of performance during startup or shutdown as they do during normal operations.

In addition, EPA expects that some glass furnaces will comply with the final rule through the use of post-combustion controls like SCR, which cannot function properly when the exhaust temperature does not meet the operating conditions needed for the catalyst (i.e., 570 – 840 °F). This may run the risk of forming ammonium bisulfates and result in damage to the equipment. The alternative requirements in § 52.44(d)-(f) provide additional time for flue gas temperatures to reach optimal operating conditions.

During periods when glass pull is not occurring (i.e., idling), fuel must continue to be fired to ensure molten glass does not solidify and damage the furnace. Idling periods occur when there may be a need for a temporary transitional period of the batch material, where shutting down or restarting the furnace may not be feasible. The idling periods allow for the furnace to transition from one different batch of raw materials to the next for operators to transition from one glass product to another. Since the emissions limits under § 52.44(c) are expressed in pounds of NOx per ton of glass produced, it is not possible for a glass furnace to comply with the limits when there is no glass production or abnormally low glass production. However, as with startup and shutdown, owners and operator must operator their controls as soon as technically feasible and must meet a daily emissions limit applicable during idling periods (this is described in more detail under factor 4 below).

(3) The alternative emission limitation requires that the frequency and duration of operation in startup or shutdown mode are minimized to the greatest extent practicable;

The final rule establishes limits on the number of days that each startup or shutdown period may last (ranging from 40 to 104 days), depending on the type of glass furnace. During shutdown operations, the owner or operator is required to measure the duration of the glass melting furnace shutdown. The shutdown period will be measured from the time the furnace operation drops below 25 percent of the permitted production capacity or fuel use capacity to when all emissions from the furnace cease. The shutdown period of the glass melting furnace may not exceed 20 days. Additionally, the owner or operator must maintain operating records and additional documentation as necessary to demonstrate compliance with these requirements.

(4) As part of its justification of the SIP revision, the state analyzes the potential worst-case emissions that could occur during startup and shutdown based on the applicable alternative emission limitation;

In 1994, the Emission Standards Division of the Office of Air Quality Planning and Standards of the U.S. Environmental Protection Agency issued a report detailing alternative control techniques (ACTs) for NOx emissions from glass manufacturing facilities. Within this report, the following table below was included and summarized the uncontrolled NOx emissions identified from glass manufacturing furnaces:[62]

Furnace type	Uncontrolled NO_x emissions, lb NO_x/ton
Container glass	10.0
Flat glass	15.8[26]
Pressed/blown glass	22.0

These values represent worst case NOx emission, in pounds of NOx emitted by ton of glass produced, from each respective glass furnace type during normal operation in the absence of emission control technology.

During periods of idling, affected units must comply with an alternative emission limit calculated in accordance with a specific equation to limit emissions to an amount (in pounds per day) that reflects the furnace's permitted production capacity in tons of glass produced per day. Additionally, the owner or operator must operate the emissions control system to minimize emissions whenever technologically feasible.

(5) The alternative emission limitation requires that all possible steps are taken to minimize the impact of emissions during startup and shutdown on ambient air quality;

[62] EPA, Alternative Control Techniques Document— NOx Emissions from Glass Manufacturing, EPA-453/R-94-037 (June 1994) at 4-10.

The owner or operator must maintain all records necessary to demonstrate compliance with the startup and shutdown requirements. Additionally, the owner or operator must place the emissions control system in operation as soon as technologically feasible during start-up to minimize emissions. During shutdown operations, owner or operators are required to measure the time the furnace operation drops below 25 percent of the permitted production capacity or fuel use capacity to when all emissions from the furnace cease. During this period, the owner or operator of a glass melting furnace must operate the emissions control system whenever technologically feasible during shutdown to minimize emissions.

(6) The alternative emission limitation requires that, at all times, the facility is operated in a manner consistent with good practice for minimizing emissions and the source uses best efforts regarding planning, design, and operating procedures;

During all periods of startup, shutdown, and idling, the owner or operator of a glass melting furnace subject to § 52.44 must operate the emissions control system whenever technologically feasible, in order to minimize emissions during these periods.

(7) The alternative emission limitation requires that the owner or operator's actions during startup and shutdown periods are documented by properly signed, contemporaneous operating logs or other relevant evidence.

Each owner or operator of an affected unit seeking to comply with alternative work practice standards in lieu of emission limits under § 52.44(c) during startup or shutdown must submit specific information to the Administrator no later than 30 days prior to the anticipated date of startup or shutdown. The following detailed information must be included in this submission: (i) A detailed list of activities to be performed during startup or shutdown and explanations to support the length of time needed to complete each activity; (ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the startup or shutdown period; (iii) Identification of the control technologies or strategies to be utilized; (iv) A description of the physical conditions present during startup or shutdown periods that prevent the controls from being effective; (v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

Additionally, each owner or operator must maintain all records necessary to demonstrate compliance with the startup and shutdown requirements, including but not limited to records of material process flow rates, system operating parameters, the duration of each startup and shutdown period, fuel throughput, oxidant flow rate, and any additional records necessary to determine whether the stoichiometric ratio of the primary furnace combustion system exceeded 5 percent excess oxygen during startup. The owner or operator must maintain records of daily NOx emissions in pounds per day for purposes of determining compliance with the applicable emissions limit for idling periods under paragraph (f)(2). Each owner or operator shall also record the duration of each idling period.

Performance Tests and Monitoring

EPA solicited comment on whether it was feasible or appropriate to require affected units to be equipped with CEMS to measure and monitor the NOx concentration (emissions level) instead of conducting performance tests on a semiannual basis.

After review of the comments received at proposal and EPA's assessment of practices conducted within the glass manufacturing industry, EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnaces to demonstrate compliance with the emissions limits through CEMS or through an annual performance test along with continuous parametric monitoring.

Affected units subject to this rule that operate NOx CEMS meeting specified requirements may use CEMS data in lieu of performance tests and continuous parametric monitoring to demonstrate compliance. For affected units that do not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly glass production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NOx emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance test does not have to be performed during ozone season. Owners and operators of affected units must also reassess and adjust the site-specific operating parameters in accordance with the results of each performance test, and report and include ongoing site-specific operating parameter data in the annual reports to EPA and the semi-annual title V monitoring reports to the relevant air permitting authority.

6 Boilers from Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel and Ferroalloys Manufacturing Industry

A. Applicability and form of final emissions limits for industrial boilers.

EPA is establishing regulatory requirements for boilers that have a design capacity of 100 mmBtu/hr or greater within the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel and Ferroalloys Manufacturing industry. The rationale for the inclusion of these sources in the rule is derived from the Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026, herein referred to as the Non-EGU Screening Assessment, or the Screening Assessment, and further discussed in Section V of the final rule preamble. As described within the Screening Assessment, EPA reviewed the projected 2026 emissions data to identify large boilers within certain industries, defined as boilers projected to emit more than 100 tons per year in 2026. Boilers meeting this threshold were found in five industries, as identified in Table 6.A below.

Table 6.A: 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
Iron and Steel and Ferroalloys Manufacturing	3311xx
Metal Ore Mining	2122xx

While certain industries (e.g., Metal Ore Mining) may have relatively few boiler units, each of these five industries was nonetheless found to be impactful of downwind air quality in the Screening Assessment. Further, this rule focuses on boilers as the most impactful emissions-unit types with cost-effective emissions reduction potential within these industries as a whole. Therefore, the final rule applies to boilers in these industries even if an impactful industry may have relatively few boilers. In addition, to the extent such boiler units are used at facilities within any of the other impactful industries covered by the rule (in particular, Iron and Steel and Ferroalloys Manufacturing), because these boilers have a similar profile in terms of cost-effective emissions reduction potential, they too are covered in this final rule.

Based on a review of the potential emissions from industrial boilers of various fuel types as described in this section, 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, EPA is establishing NOx emissions limits for all new and existing boilers found within any of the 20 states with non-EGU emission reduction obligations that are within these five industries and have a design capacity of 100 mmBTU/hr or greater. EPA solicited comment on alternative applicability thresholds. Based on comments received on the proposal, we have modified the applicability criteria of the final rule by providing a low-use exemption to boilers that operate less than 10% per year, on an hourly basis, based on the three most recent years of use and no more than 20% in any one of the three years. These units will still have recordkeeping obligations.

EPA reviewed a number of state RACT rules to determine the typical form of emission limits within them. Based on this review, EPA found that NOx limits for industrial boilers most often take a form expressed as mass (i.e., pounds) of NOx emitted per heat input (i.e., million BTUs) combusted per hour. EPA's NOx emissions limits for this source category in this rule take the same form.

Specifically, EPA is establishing an applicability threshold based on a design capacity of 100 mmBtu/hr or greater. NOx emissions from boilers rated at 100 mmBtu/hr or greater can be significant, particularly if they do not operate NOx control equipment. Based on our review of the potential emissions from industrial boilers of various fuel types we conclude that use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the selection of 100 tons/year used within the Non-EGU Screening Assessment memorandum. An evaluation of potential NOx emissions from various fossil-fueled industrial boilers with a design capacity of 100 mmBtu/hr is provided below.

<u>1. Potential emissions from coal-fired industrial boilers</u>

The potential emissions from a coal-fired industrial boiler with a design capacity of 100 mmBtu/hr was estimated using an average NOx emission factor from EPA's emission factor reference document, AP-42,[63] along with an approximate heating value for coal from Appendix A of AP-42. The emission factor used was derived by calculating the average of 13 "A" rated NOx emission factors from AP-42's Table 1.1-3 – Emission Factors for SOx, NOx, and CO from Bituminous and Subbituminous Coal Combustion. The average of the 13 values was 14.1 lbs NOx per ton of coal burned. The heating value from Appendix A for bituminous coal is 13,000 BTUs per pound, which equates to 26 million BTUs per ton of coal. The following calculation provides the maximum potential emissions from an industrial boiler with these parameters:

*(14.1 lbs NOx/ton coal) * (1 ton coal/26 mmBtu) * (100 mmBtu/hr) * (8,760 hr/yr) *(1 ton/2000 lbs) = 237.5 tons NOx/year.*

The above represents the maximum potential emissions from a coal-fired boiler emitting at the rate shown in the equation; boilers operating less than 8,760 hours per year would emit proportionally less than the maximum amount illustrated in the above equation.

<u>2. Potential emissions from oil-fired industrial boilers.</u>

The potential emissions from a residual and a distillate oil-fired industrial boiler with a design capacity of 100 mmBtu/hr was estimated in a manner similar to the approach described

[63] Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources; U.S. EPA, Office of Air Quality Planning and Standards; available at: https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

above for a coal-fired industrial boiler. For a residual oil-fired industrial boiler, a NOx emission factor of 47 lbs NOx per 1,000 gallons of oil burned was taken from Table 1.3-1, Criteria Pollutant Emission Factors for Fuel Oil Combustion, of section 1.3, Fuel Oil Consumption, of AP-42, and a heating value of 150,000 BTUs per gallon for residual oil as reported in Appendix A to AP-42 was used. The heating value equates to 150 million BTUs per 1,000 gallons used. The following calculation provides the maximum potential emissions from an industrial boiler with these parameters:

*(47 lbs NOx/1,000 gallons) * (1,000 gallons/150 mmBtu) * (100 mmBtu/hr) * (8,760 hr/yr) *(1 ton/2000 lbs) = 137.2 tons NOx/year.*

For a distillate oil-fired boiler, an emission factor of 24 lbs NOx/1,000 gallons from Table 1.3-1 was used in conjunction with a heat rate of 140,000 BTUs per gallon from Appendix A. Substituting these values into the above equation yields a result of 75.1 tons per year. Although this result is below 100 tons per year, the emission factor used, which was the only one available for industrial boilers of this size and fuel type within AP-42 is rated "D", meaning there is likely to be a fairly wide range in emission rates from individual boilers of this type.

The above analysis represents the maximum potential emissions from a residual and a distillate-fired industrial boiler emitting at the rates shown in the equations above; boilers operating less than 8,760 hours per year would emit proportionally less than the maximum amounts illustrated in the above equations.

<u>3. Potential emissions from a natural gas-fired industrial boiler.</u>

The potential emissions from a natural gas-fired industrial boiler with a design capacity of 100 mmBtu/hr was estimated in a manner similar to the approach described above for coal and oil-fired industrial boilers. For a natural gas-fired industrial boiler, a NOx emission factor of 235 lbs NOx per million standard cubic feet (SCF) used was obtained from Table 1.4-1, Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion, of section 1.4, Natural Gas Consumption, of AP-42. The emission factor represents the average of the emission factors for a pre and a post-NSPS natural gas-fired industrial boiler. A heating value of 1,050 BTUs per SCF as reported in Appendix A to AP-42 was used in the calculation. The heating value equates to 1,050 mmBtu per million SCF. The following calculation provides the maximum potential emissions from an industrial boiler with these parameters:

*(235 lbs NOx/mm SCF) * (1 mm SCF/1,050 mmBtu) * (100 mmBtu/hr) * (8,760 hr/yr) *(1 ton/2000 lbs) = 98 tons NOx/year.*

The above analysis represents the maximum potential emissions from a residual and a distillate-fired industrial boiler emitting at the rates shown in the equations above; boilers operating less than 8,760 hours per year would emit proportionally less than the maximum amounts illustrated in the above equations. This value is sufficiently close to 100 tpy that applying the 100 mmBtu/hr design capacity for natural-gas fired boilers adequately approximates the 100 tpy figure used in the Screening Assessment.

B. Final Emissions Limitations and Rationale

EPA reviewed NOx 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. Based on that review, EPA is establishing the following NO_X emissions limits for coal, oil, and gas-fired industrial boilers:

Table 6.B: Final NO_X Emissions Limits for Industrial Boilers > 100 mmBtu/hr

Unit type	Emissions limit (lbs NOx/mmBtu)	Additional Information
Coal	0.20	Limits reviewed ranged from 0.08 to 1.0. Final 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. Final limit will likely require combustion controls.
Distillate oil	0.12	Limits reviewed ranged from 0.10 to 0.43. Final limit will likely require combustion controls.
Natural gas	0.08	Limits reviewed ranged from 0.06 to 0.25. Final limit will likely require a combination of combustion controls or post-combustion controls.

Generally, the emissions limits in Table 6.B can be met through installation and operation of the following controls: 1) SCR for coal-fired boilers; 2) SCR for residual oil-fired boilers; 3) SCR for distillate oil-fired boilers; and low-nox burners and FGR for natural gas-fired boilers.

EPA's Menu of Control Measures (MCM) document contains numerous examples of NOx control equipment that has been demonstrated to effectively reduce emissions from industrial boilers. Table 7 below provides information pertaining to industrial boilers from the MCM, indicating that 9 different control technologies or combinations of technologies have been shown to reduce NOx emissions from industrial boilers with control efficiencies ranging from 35 to 90 percent. This information from the MCM can also be found in the Control Measures Database (CMDB), a major input to the Control Strategy Tool (CoST), which EPA used in the NOx control strategy analysis included in the Non-EGU Screening Assessment memorandum.[64] Table 6.G at the end of this section presents a list of emissions control technologies excerpted from the MCM.

Additional information on EPA's analysis of state-adopted emissions limits for industrial boilers with design capacities of 100 mmBtu/hr or greater fueled by coal, oil, or natural gas, and the control technologies available to reduce NOx emissions from this equipment is provided below.

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[64] EPA, Control Measures Database (CMDB) for Stationary Sources, available at https://www.epa.gov/system/files/other-files/2021-09/cmdb_2021-09-02_0.zip (URL dated January 6, 2022).

1. Coal-fired industrial boilers

For coal-fired industrial boilers subject to the requirements of the final rule, EPA is establishing an emission limit of 0.20 lb/MMBtu on a 30-day rolling basis. Various forms of combustion and post-combustion NOx control technology exist that should enable most existing facilities to be retrofit with equipment that will enable them to meet this emissions limit. Additionally, many states containing ozone nonattainment areas or located within the Ozone Transport Region (OTR) have already adopted emission limits similar to the recommended emission limit. Furthermore, some coal-fired industrial boilers may have installed combustion or post-combustion control equipment to meet the emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that coal-fired industrial boilers meet a NOx emissions limit of between 0.5 and 0.8 lb/MMBtu depending on unit type.[65]

There are two main types of NOx control technology that can be retrofit to most existing industrial boilers, or incorporated into the design of new boilers, to meet the final emissions limit. These two control types are combustion controls and post-combustion controls, and in some instances both types are used together. As noted within EPA's "Alternative Control Techniques Document – NOx Emissions from Industrial / Commercial / Institutional (ICI) Boilers" (hereafter "ICI Boiler ACT"),[66] the type of NOx control available for use on a particular unit depends primarily on the type of boiler, fuel type, and fuel-firing configuration. We note that although the ICI Boiler ACT also addresses emissions from commercial and institutional boilers, we are not proposing emissions limits for those types of boilers; rather, we are only proposing limits for certain types of industrial boilers. For example, Table 2-3 of the ICI Boiler ACT indicates which types of combustion and post-combustion NOx 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 NOx control equipment for industrial boilers, including a document prepared by the Northeast States for Coordinated Air Use Management entitled, "Applicability and Feasibility of NOx, SO2, and PM Emission Control Technologies for Industrial, Commercial, and Institutional Boilers" (November 2008, revised January 2009); the "EPA Air Pollution Control Cost Manual," Section 4, Chapter 1: Selective Noncatalytic Reduction, April, 2019 and Chapter 2, Selective Catalytic Reduction, June 2019; and a document issued by the Institute of Clean Air Companies entitled, "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources," December, 2006.

Table 6.C provides examples of NOx emission limits for coal-fired ICI boilers rated at 100 mmBTU/hr or greater that have been adopted by various states.

[65] 40 CFR 60.44b.
[66] EPA, Alternative Control Techniques Document – NOx Emissions from Industrial / Commercial / Institutional (ICI) Boilers, EPA-453/R-94-022 [DATE].

Table 6.C: NOx Emission Limits, Averaging Times, and State Citations for Coal Fired ICI Boilers

State	Emission limit (lb/mmBtu)	Averaging time	State rule citation and website
CT	0.12[67] ozone season; 0.15 non-ozone season	Daily block average for units with CEMS, for other units, as developed during stack testing. For non-ozone season, rate is avg. for non-ozone season.	Section 22a-174-22e of the Regulations of Connecticut State Agencies, at paragraph (d)(2)(C): https://eregulations.ct.gov/eRegsPortal/Browse/RCSA/Title_22aSubtitle_22a-174Section_22a-174-22e/
MA	0.12	One-hour, unless equipped with CEMS, then daily.	Regulation 310 of the Code of Massachusetts Regulations (CMR), 7.00, Air Pollution Control, Section 7.19, RACT for Sources of NOx, at paragraph (4)(b): https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download
DE	0.38	24 hour rolling basis.	Title 7, Natural Resources and Environmental Control, Section 1112, Control of Nitrogen Oxide Emissions, at Table 3-1: https://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml
NY	0.08 – 0.20	CEMS or 1-hour average.	Title 6, Dept. of Environmental Conservation; Chapter III. Air Resources; Subchapter A. Prevention and Control of Air Contamination and Air Pollution; Part 227. Stationary Combustion Installations; Subpart 227-2. RACT for Major Sources of NOx. NY NOx RACT Regulation

2. Oil-fired industrial boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. Based on our review of available information as described below, the NOx emission limit for residual oil-fired boilers is 0.20 lb/mmBtu, and the NOx emission limit for distillate oil-fired boilers is 0.12 lb/mmBtu, with both limits based on a rolling, 30-day average basis. As with coal-

[67] Beginning in 2023.

fired industrial boilers, a number of combustion and post-combustion NOx control technologies exist that should enable most facilities to meet these emission limits, and numerous examples exist of states that have already adopted emission limits similar to the emissions limits in this final rule. Table 2-3 of the ICI Boiler ACT indicates that two types of NOx combustion control, low-NOx 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 emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that distillate oil-fired units meet a NOx emission limit of between 0.1 to 0.2 lb/MMBtu depending on heat release rate, and residual oil-fired units meet a NOx emission limit of between 0.3 to 0.4 lb/MMBtu also depending on heat release rate.[68] The additional resources noted in the paragraph above discussing coal-fired industrial boilers also contain useful information regarding effective NOx control equipment for residual and distillate fueled industrial boilers.

Table 6.D provides examples of NOx emission limits for oil-fired ICI boilers rated at 100 mmBTU/hr or greater that have been adopted by various states.

Table 6.D: NOx Emission Limits, Averaging Times, and State Citations for Oil-Fired ICI Boilers Rated at 100 mmBTU/hr or Greater

State	**Emission limit** (lb/mmBTU)	**Averaging time**	**State rule citation**
CT[69]	Residual oil: 0.20 Other oil: 0.15	Daily block average for units with CEMS, for other units, as developed during stack testing.	Section 22a-174-22e of the Regulations of Connecticut State Agencies, at paragraph (d)(3)(C): https://eregulations.ct.gov/eRegsPortal/Browse/RCSA/Title_22aSubtitle_22a-174Section_22a-174-22e/
MA	0.15	One-hour, unless equipped with CEMS, then daily.	310 CMR 7.19, at paragraph (4)(b): https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download
DE	0.25 all boilers except cyclone boilers; cyclone boilers, 0.43	24 hour rolling basis.	Title 7, Natural Resources and Environmental Control, Section 1112, Control of Nitrogen Oxide Emissions, at Table 3-1: https://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml
NY	0.15 – 0.20	CEMS or 1-hour average.	Same citation as shown in Table 3.

[68] 40 CFR 60.44b.
[69] Rates shown for CT are applicable during the ozone season.

State	Emission limit (lb/mmBTU)	Averaging time	State rule citation
NJ	Distillate – 0.10 Other liq. – 0.20	If CEMs, daily avg., otherwise, periodic stack test	Title 7, New Jersey Administrative Code, Chapter 27, Subchapter 19, Control and Prohibition of Air Pollution from Oxides of Nitrogen, available at: https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf
San Diego County APCD	Distillate - 40 ppm @ 3% O2 (equates to 0.05)	NA	Rule 69.2: Industrial and Commercial Boilers, Process Heaters, and Steam Generators: https://www.sdapcd.org/content/dam/sdapcd/documents/rules/current-rules/Rule-69.2.pdf

3. Gas-fired industrial boilers

The final NOx emission limit for gas-fired boilers is 0.08 lb/mmBtu on a 30-day rolling average basis. As with fossil-fuel-fired boilers mentioned above, numerous combustion and post-combustion NOx control technology exist that should enable most facilities to meet these emission limits, and many examples exist of states that have already adopted emission limits similar to the emissions limits in this final rule. Table 2-3 of the ICI Boiler ACT indicates the same control technologies suitable to application to oil-fired boilers are also likely to be effective at controlling NOx emissions from gas-fired industrial boilers. Some gas-fired industrial boilers may have already installed combustion or post-combustion control equipment to meet the emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that gas-fired units meet a NOx emission limit of between 0.1 to 0.2 lb/MMBtu depending on heat release rate. The additional resources noted in the discussion of coal-fired industrial boilers also contain useful information regarding effective NOx control equipment for gas-fired industrial boilers.

Table 6.E provides examples of NOx emission limits for gas-fired ICI boilers rated at 100 mmBTU/hr or greater that have been adopted by various states.

Table 6.E: NOx Emission Limits, Averaging Times, and State Citations for Gas Fired ICI Boilers with a Design Capacity of 100 mmBTU/hr or Greater

State	Emission limit (lb/mmBTU)	Averaging time	State rule citation
CT[70]	0.10	Daily block average for units with CEMS, for other units, as developed during stack testing.	Section 22a-174-22e of the Regulations of Connecticut State Agencies, at paragraph (d)(3)(C): https://eregulations.ct.gov/eRegsPortal/Browse/RCSA/Title_22aSubtitle_22a-174Section_22a-174-22e/
MA	0.06	One-hour, unless equipped with CEMS, then daily.	310 CMR 7.19, at paragraph (4)(b): https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download
DE	0.20	24 hour rolling basis.	Title 7, Natural Resources and Environmental Control, Section 1112, Control of Nitrogen Oxide Emissions, at Table 3-1: https://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml
NY	0.08	CEMS or 1-hour average.	Same as citation shown in Table 3.
NJ	0.10	If CEMS, daily average; otherwise, periodic stack test.	Title 7, New Jersey Administrative Code, Chapter 27, Subchapter 19, Control and Prohibition of Air Pollution from Oxides of Nitrogen, available at: https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf
Bay Area AQMD	5 ppm @ 3% O2 (equates to 0.006)	NA	Regulation 9, Rule 7:Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters: https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-7-nitrogen-oxides-and-carbon-monoxide-from-industrial-institutional-and-commercial-boiler/documents/rg0907.pdf?la=en&rev=ab95f36c2dd146528f1cf3c10596bce3

[70] Rates shown for CT are applicable during the ozone season.

State	Emission limit (lb/mmBTU)	Averaging time	State rule citation
San Diego County APCD	30 ppm @ 3% O2 (equates to 0.036)	NA	Rule 69.2: Industrial and Commercial Boilers, Process Heaters, and Steam Generators: https://www.sdapcd.org/content/dam/sdapcd/documents/rules/current-rules/Rule-69.2.pdf

In addition to the above, many BACT determinations exist containing NOx emissions limits for industrial boilers sized 100 mmBTU/hr and greater that are more stringent than the limits shown in the above table. For example, Table B.3 of a document prepared by the Illinois EPA entitled, "Project Summary for a Construction Permit Application from Cronus Chemicals, LLC, for a Fertilizer Manufacturing Facility near Tuscola, Illinois" identifies 17 NOx BACT determinations for boilers sized 100 mmBTU/hr or greater containing emissions limits that range from 0.011 to 0.06 lbs/mmBTU. See: http://www.epa.state.il.us/public-notices/2014/cronus-chemicals/project-summary.pdf. An additional example of stringent NOx emissions limits for gas-fired industrial boilers in this size range can be found within South Carolina's Air Pollution Control Regulations and Standards, within Regulation 61-62. Regulation 62.5, Standard No. 5.2, Control of Oxides of Nitrogen, requires as noted within Table 1 that new industrial boilers sized 100 mmBTU/hr or greater meet a NOx emissions limit of 0.036 lbs/mmBTU.

4. Industrial boilers using other fuels

We anticipated that there may be industrial boilers rated at 100 mmBtu/hr or greater located at one of the indicated industries powered by other fuels such as wood or industrial process gas. EPA solicited comment on whether EPA should establish emission limits for such other types of fuels as part of this action. Based on our review and consideration of comments received on the proposal we decided to finalize emissions limits only for those boilers that receive 90% or more of their heat-input from coal, residual or distillate oil, or natural gas, or combinations of these fuels. We anticipate that most boilers that burn less than 10% of other fuels should be able to meet the emissions limit for the primary fuel burned using identified, cost-effective, conventional control technologies. If not, the final rule provides a mechanism to request from EPA an alternative emissions limit based on a showing of technical impossibility or extreme economic hardship. Based on our understanding of the universe of boilers in the affected states and industries, we anticipate approximately 150 boilers meet the applicability criteria we are adopting in the final rule. Of final note, based on comments received on the proposal the final rule provides a formula that can be used to derive the emissions limit for a boiler that burns combinations of coal, residual oil, distillate oil, or natural gas.

D. Compliance Assurance Requirements

Affected units subject to this rule that operate NOx CEMS meeting specified requirements may use CEMS data in lieu of periodic stack tests and continuous parametric monitoring to demonstrate compliance. Many boilers subject to the requirements of this section of the FIP will likely demonstrate compliance in a manner similar to the emissions monitoring requirements found within the NSPS for industrial, commercial, and institutional (ICI) boilers at 40 CFR Part 60 Subpart D, at section 60.46b. Those requirements include, among other provisions, the performance of an initial compliance test and installation of a CEMS. The final FIP includes a CEMS opt-out provision similar to that within 40 CFR Part 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators, for sources whose initial compliance test indicates the unit emits at 70% or less of the applicable standard. Additionally, based on comments received on the proposal, the final rule allows boilers with heat input capacities of less than 250 mmBTU/hr to perform an alternative monitoring technique that is based on an initial and periodic stack test and development of a parametric monitoring plan.

The final rule requires that the initial compliance test be conducted no later than 90 days after the installation of pollution control equipment applied to meet the emission limits, and performed as described under 40 CFR Part 60.8 using the continuous system for monitoring NOx 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. The final rule also requires that the initial compliance test be conducted no later than the May 1, 2026 compliance date.

Table 6.G: Excerpt from Menu of Control Measures Applicable to Industrial Boilers

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Industrial/ Commercial/ Institutional Boilers - Coal	Selective Catalytic Reduction	80	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal ICI boilers with NOx emissions greater than 10 tons per year.	EPA 2003b, EPA 1998e
Industrial/ Commercial/ Institutional Boilers - Coal	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2003b, Pechan 2006
Industrial/ Commercial/ Institutional Boilers - Coal or Petroleum Coke	Low NOx Burner	50	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, OTC/LADCO 2010

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to coal/wall fired ICI boilers and Petroleum coke fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	
Industrial/ Commercial/ Institutional Boilers - Coal or Petroleum Coke - Wall Fired	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to wall fired (coal) IC boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal-fired and petroleum coke-fired IC boilers with uncontrolled NOx	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, OTC/LADCO 2010

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	
Industrial/ Commercial/ Institutional Boilers - Coal/ Bituminous	Low NOx Burner and Over Fire Air	51	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to bituminous coal Industrial/Commercial/Institutional (ICI) boilers.	EPA 2003b, Pechan 2006
Industrial/ Commercial/ Institutional Boilers - Coal/ Subbituminous	Low NOx Burner	51	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by	EPA 2003b, Pechan 2006, OTC/LADCO 2010

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to subbituminous coal industrial/commercial/institutional boilers. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Coal Reburn	50	This control reduces NOx emissions through coal reburn. This control is applicable to coal/cyclone ICI boilers.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 1994g, Cadmus 1995
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Natural Gas Reburn	55	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, ERG 2000, EPA 1994g

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to coal/cyclone ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Selective Catalytic Reduction	90	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal/cyclone ICI boilers with nameplate capacity greater than 25 MW (250 mmBTU/hr).	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, EPA 2010a
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Selective Non-Catalytic Reduction	35	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal/cyclone IC boilers with	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Coal/ Fluidized Bed Combustion	Selective Catalytic Reduction	90	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to fluidized bed combustion coal ICI boilers.	EPA 2007b
Industrial/ Commercial/ Institutional Boilers - Coal/ Fluidized Bed Combustion	Selective Non-Catalytic Reduction - Urea	75	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal-fired/fluidized bed combustion IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g
Industrial/ Commercial/ Institutional	Selective Catalytic Reduction	90	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based	EPA 2007b

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Boilers - Coal/ Stoker			on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal/stoker IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Coal/ Stoker	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to coal/stoker IC boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal/stoker IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g
Industrial/ Commercial/ Institutional Boilers - Coal/ Subbituminous	Low NOx Burner and Over Fire Air	65	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of	EPA 2003b, Pechan 2006

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			oxygen available in another. This control applies to subbituminous coal Industrial/Commercial/Institutional (ICI) boilers.	
Industrial/ Commercial/ Institutional Boilers - Coal/ Wall	Selective Catalytic Reduction	90	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal/wall IC boilers with nameplate capacity greater than 25 MW.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, EPA 2010a
Industrial/ Commercial/ Institutional Boilers - Distillate Oil	Selective Catalytic Reduction	80	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to distillate oil-fired ICI boilers with nameplate capacity greater than 25 MW.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 2007d, Sorrels 2007, EPA 2010a

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Low NOx Burner	50	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to Oil and LPG ICI boilers with uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, OTC/LADCO 2010
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Low NOx Burner and Flue Gas Recirculation	60	This control is the use of low NOx burner (LNB) technology and FGR to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1993c

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			amount of oxygen available in another. This control is applicable to distillate oil-fired ICI boilers and LPG-fired ICI Boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Selective Non-Catalytic Reduction	50	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil and LPG-fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g
Industrial/ Commercial/ Institutional Boilers - Gas	Low NOx Burner and Flue Gas Recirculation + Over Fire Air	80	This control is the use of low NOx burner (LNB) technology, flue gas recirculation (FGR), and over fire air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to gas	EPA 2003b, EPA 1998e

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			Industrial/Commercial/Institutional (ICI) boilers.	
Industrial/ Commercial/ Institutional Boilers - Gas	Low NOx Burner and Over Fire Air	60	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to gas Industrial/Commercial/Institutional (ICI) boilers.	EPA 2003b, Pechan 2006
Industrial/ Commercial/ Institutional Boilers - Gas	Selective Catalytic Reduction	80	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2003b, EPA 1998e
Industrial/ Commercial/	Selective Non-	40	This control is the reduction of NOx emission through selective non-	EPA 2003b, Pechan 2006

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Institutional Boilers - Gas	Catalytic Reduction		catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Natural Gas	Selective Non-Catalytic Reduction	50	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Low NOx Burner	50	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas and process gas fired ICI boilers with	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, OTC/LADCO 2010

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Low NOx Burner and Flue Gas Recirculation	60	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired and process gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1993c
Industrial/ Commercial/ Institutional	Oxygen Trim and	65	This control is the use of Oxygen Trim and Water Injection to reduce NOx emissions. Water is injected into the	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, ERG 2000, EPA 1994g

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Boilers - Natural Gas or Process Gas	Water Injection		gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired and process gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Selective Catalytic Reduction	80	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired and process gas-fired ICI boilers nameplate capacity greater than 25 MW.	EPA 2006b, EPA 1998e, EPA 2002a, EPA 2007d, Sorrels 2007, EPA 2010a
Industrial/ Commercial/ Institutional Boilers - Oil	Low NOx Burner and Over Fire Air	50	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion	EPA 2003b, Pechan 2006

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			zone and reducing the amount of oxygen available in another. This control applies to oil Industrial/Commercial/Institutional (ICI) boilers.	
Industrial/ Commercial/ Institutional Boilers - Oil	Selective Catalytic Reduction	80	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2003b, EPA 1998e
Industrial/ Commercial/ Institutional Boilers - Oil	Selective Non-Catalytic Reduction	40	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to oil IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2003b, Pechan 2006

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Low NOx Burner	50	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired ICI boilers and liquid waste fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers".	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g, OTC/LADCO 2010
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Low NOx Burner and Flue Gas Recirculation	60	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1993c

Source Category	Emission Reduction Measure	Control Efficiency (%)	Description/Notes/Caveats	References
			the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired and liquid waste-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Selective Non-Catalytic Reduction	50	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to residual oil and liquid waste-fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	EPA 2006b, Pechan 2001, EPA 1998e, EPA 2002a, EPA 1994g

The information in the table above is an excerpt from EPA’s Menu of Control Measures.

7 Municipal Waste Combustors

MWCs include solid waste incinerators and combustors. MWCs emit substantial amounts of NOx, and some states have required emission limits for these facilities that are more stringent than the federal requirements contained within EPA's NSPS for this industry. EPA has received comments in past transport rulemakings that emission reductions should be sought from MWCs, as noted within the RCU proposed rule (85 FR 68993). At proposal, EPA solicited comments on whether NOX emissions reductions should be sought from municipal waste combustors (MWCs) to address interstate ozone transport and sought comment on whether to require in the final rule specific potential emissions limits, control technologies, and control costs. EPA requested comment on emissions limits of 105 parts per million by volume, dry (ppmvd) on a 30-day average and a 110 ppmvd on a 24-hour average based on determinations made in the June 2021 Ozone Transport Commission (OTC) *Municipal Waste Combustor Workgroup Report* (OTC MWC Report). *See* 87 FR 20085-20086. The OTC MWC Report found that MWCs in the OTR are a significant source of NOx emissions and that significant annual NOx reductions could be achieved from MWCs in the OTR using several different technologies, or a combination of technologies, at a reasonable cost. In consideration of the findings from the OTC MWC report and recent memorandum of understanding (MOU) between OTC states,[71] the fact that many state RACT NOX rules for ozone nonattainment areas or in the OTR apply to MWCs, and information received during public comment, EPA is finalizing NOx emissions limits of 110 ppmvd at 7 percent oxygen on a 24-hour averaging period and 105 ppmvd at 7 percent oxygen on a 30-day averaging period, applicable to new and existing municipal waste combustor units with a combustion capacity greater than 250 tons per day.

Summary of MWC Industry and Emissions

MWCs burn garbage and other non-hazardous solid material using a variety of combustion techniques. Section 2.1, Refuse Combustion, of EPA's emission factor reference document, AP-42, contains a description of the seven different combustion process technologies most commonly used in the industry. 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 NOx, which forms through oxidation of nitrogen in the waste and from fixation of nitrogen in the air used to burn the waste. NOx emissions from MWCs are typically released through tall stacks which enables the emissions to be transported long distances.

Most MWCs are co-generation facilities in that they recover heat from the combustion process to power a turbine to produce electricity. According to a 2018 report from the Energy Recovery Council,[72] 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

[71] Ozone Transport Commission, *Memorandum of Understanding Among the States of the Ozone Transport Commission to Pursue Additional Reductions of Oxides of Nitrogen Emissions from Municipal Waste Combustors* (June 2, 2022).
[72] "2018 Directory of Waste to Energy Facilities"; Energy Recovery Council.

compared to the EGUs that will be regulated per the requirements of the final FIP, with most MWCs having an electrical output capacity of less than 25 MW. Appendix 1 of this TSD contains a Microsoft Excel spreadsheet listing all of the MWC units in the U.S. and includes each unit's electrical output capacity as reflected in EPA's most recent version of the NEEDS database (June 2021). All MWCs in the states included in the final FIP have an electrical output capacity of less than 25 MW. The average electrical output capacity is 12.8 MW.

MWC Facility Inventory

EPA conducted an internal analysis of existing MWC facilities across the 20 states subject to this rule. The facility inventory was created using 2019 NEI data as well as 2021 data from the National Electric Energy Data System or "NEEDS" database. These databases provided the facility names and 2019 NOx emissions values. The NOx emissions limit data was sourced from facility operating permits and supplemented by information found in the OTC's MWC report, Appendix A. Information on the type of combustor and the control technology currently installed at these facilities was pulled over from an EPA database and placed in a document entitled "2019 LMWC SMWC Inventory w APCD 09012022," which can be found in the docket's supporting materials. Finally, the "Controls Expected to be Installed" column contains a list of controls that EPA expects facilities to install to achieve the NOx emissions limits, based on the combustor type, the controls already installed, and the cost effectiveness of the control technology compared to other control options. The full MWC facility inventory entitled *MWC Inventory for 2015 Ozone Transport Final Rule* and can be found in the supporting materials of this docket.

NOx emissions from MWCs located in the upwind states identified in this final rule with non-EGU emissions reductions obligations are substantial. According to EPA's NEI database, in 2019 16,924.47 tons of annual NOx were emitted from MWCs in the nine upwind states containing them. Table 7.A contains a list of MWC facilities located within an upwind state covered by this rule along with their NOx emissions as reported to the 2019 NEI.

Table 7.A: 2019 NOx Emissions from MWC Facilities Located in States Affected by Final FIP

State	Facility Name	Combustor Type	Emissions Limit (ppmvd 24-hr limit)	2019 Emissions
CA	Covanta Stanislaus Energy	MB/WW	165	145.07
CA	Covanta Stanislaus Energy	MB/WW	165	145.07
CA	Long Beach City, Serrf Project	MB/WW	205	84.98
CA	Long Beach City, Serrf Project	MB/WW	205	487.45
CA	Long Beach City, Serrf Project	MB/WW	205	96.03
IN	Covanta Indianapolis Inc	MB/WW	205	350.41
IN	Covanta Indianapolis Inc	MB/WW	205	381.16
IN	Covanta Indianapolis Inc	MB/WW	205	390.50
MD	Montgomery County Rrf	MB/WW	140	150.08
MD	Montgomery County Rrf	MB/WW	140	153.28
MD	Montgomery County Rrf	MB/WW	140	166.55
MD	Wheelabrator Baltimore, Lp	MB/WW	150	305.44
MD	Wheelabrator Baltimore, Lp	MB/WW	150	307.53
MD	Wheelabrator Baltimore, Lp	MB/WW	150	310.75
MI	Kent County Waste To Energy Facility	MB/WW	205	153.22
MI	Kent County Waste To Energy Facility	MB/WW	205	153.60
NJ	Covanta Warren Energy Resource Co. L.P.	MB/WW	150	12.19
NJ	Covanta Warren Energy Resource Co. L.P.	MB/WW	150	12.19
NJ	Camden County Energy Recovery Associates L.P.	MB/WW	150	103.76
NJ	Camden County Energy Recovery Associates L.P.	MB/WW	150	103.76

State	Facility Name	Combustor Type	Emissions Limit (ppmvd 24-hr limit)	2019 Emissions
NJ	Camden County Energy Recovery Associates L.P.	MB/WW	150	103.76
NJ	Wheelabrator Gloucester Company L P	MB/WW	150	112.94
NJ	Wheelabrator Gloucester Company L P	MB/WW	150	112.94
NJ	Union County Resource Recovery Facility	MB/WW	150	217.05
NJ	Union County Resource Recovery Facility	MB/WW	150	217.05
NJ	Union County Resource Recovery Facility	MB/WW	150	217.05
NJ	Covanta Essex Company	MB/WW	150	268.30
NJ	Covanta Essex Company	MB/WW	150	268.30
NJ	Covanta Essex Company	MB/WW	150	268.30
NY	Babylon Resource Recovery Facility	MB/WW	150	92.61
NY	Babylon Resource Recovery Facility	MB/WW	150	92.61
NY	Wheelabrator Hudson Falls	MB/WW	150	113.46
NY	Huntington Resource Recovery Facility	MB/WW	150	119.50
NY	Huntington Resource Recovery Facility	MB/WW	150	119.50
NY	Huntington Resource Recovery Facility	MB/WW	150	119.50
NY	Wheelabrator Hudson Falls	MB/WW	150	129.54
NY	Onondaga Co Resource Recovery Facility	MB/WW	150	191.03
NY	Onondaga Co Resource Recovery Facility	MB/WW	150	191.03
NY	Onondaga Co Resource Recovery Facility	MB/WW	150	191.03

State	Facility Name	Combustor Type	Emissions Limit (ppmvd 24-hr limit)	2019 Emissions
NY	Wheelabrator Westchester Lp	MB/WW	150	319.47
NY	Wheelabrator Westchester Lp	MB/WW	150	350.29
NY	Covanta Niagara Lp	MB/WW	150	341.73
NY	Wheelabrator Westchester Lp	MB/WW	150	373.75
NY	Covanta Niagara Lp	MB/WW	150	378.41
NY	Hempstead Resource Recovery Facility	MB/WW	185	346.88
NY	Hempstead Resource Recovery Facility	MB/WW	185	346.88
NY	Hempstead Resource Recovery Facility	MB/WW	185	346.88
OK	Walter B Hall Resource Recovery Facility	CLEERGAS gasification	205	146.26
OK	Walter B Hall Resource Recovery Facility	MB/WW	205	185.95
OK	Walter B Hall Resource Recovery Facility	MB/WW	205	186.26
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	MB/WW	150	55.80
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	MB/WW	150	66.30
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	MB/WW	150	67.60
PA	York Cnty Solid Waste/York Cnty Resource Recovery	MB/RC	135	143.70
PA	York Cnty Solid Waste/York Cnty Resource Recovery	MB/RC	135	152.00
PA	York Cnty Solid Waste/York Cnty Resource Recovery	MB/RC	135	156.30
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	148.04
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	163.17

State	Facility Name	Combustor Type	Emissions Limit (ppmvd 24-hr limit)	2019 Emissions
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	163.27
PA	Lancaster Cnty Rrf/ Lancaster	MB/WW	180	172.55
PA	Lancaster Cnty Rrf/ Lancaster	MB/WW	180	176.11
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	179.06
PA	Lancaster Cnty Rrf/ Lancaster	MB/WW	180	181.76
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	185.12
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	MB/RC	180	191.95
PA	Wheelabrator Falls Inc/Falls Twp	MB/WW	150	293.45
PA	Wheelabrator Falls Inc/Falls Twp	MB/WW	150	305.81
PA	Covanta Plymouth Renewable Energy/ Plymouth	MB/WW	180	273.92
PA	Covanta Plymouth Renewable Energy/ Plymouth	MB/WW	180	283.20
VA	Wheelabrator Portsmouth	RDF	250	232.14
VA	Wheelabrator Portsmouth	RDF	250	261.26
VA	Wheelabrator Portsmouth	RDF	250	261.34
VA	Wheelabrator Portsmouth	RDF	250	297.56
VA	Covanta Alexandria/Arlington Inc	MB/WW	110	151.79
VA	Covanta Alexandria/Arlington Inc	MB/WW	110	145.20
VA	Covanta Alexandria/Arlington Inc	MB/WW	110	152.39
VA	Covanta Fairfax Inc	MB/WW	110	508.02
VA	Covanta Fairfax Inc	MB/WW	110	514.69

State	Facility Name	Combustor Type	Emissions Limit (ppmvd 24-hr limit)	2019 Emissions
VA	Covanta Fairfax Inc	MB/WW	110	506.39
VA	Covanta Fairfax Inc	MB/WW	110	453.32
			Total	**16,924.47**

This inventory and subsequent analysis revealed that all MWC units with a design capacity of 250 tons per day or greater are generally subject to emissions limits ranging from 110 to 250 ppmvd but with an average emissions limit of 163.93 ppmvd. These units include mass burn waterwall combustors, mass burn rotary combustors, refuse derived fuel (RDF) MWCs, and one modular MWC that uses gasification technology called CLEERGAS™ ("Covanta Low Emissions Energy Recovery Gasification"). To be sure that the final applicability threshold capturing units with a design capacity of 250 tons per day or greater, is consistent with the applicability thresholds in terms of PTE applied to other non-EGU sources, we analyzed the PTE of the units captured by the final applicability threshold. We found that in general, a source with a design capacity of 250 tons/day has a PTE of approximately 138 TPY. Additionally, this threshold would capture most incinerators with a PTE greater than or equal to 100 tons per year.

Summary of Federal NSPS and Emission Guideline NOx limits.

EPA has promulgated NOx emission 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 NOx 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 NOx 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.

NOx limits adopted by states for MWCs.

Section 182(b)(2) and (f) of the CAA require states containing Moderate or higher classification ozone nonattainment areas to adopt regulations with control requirements representing reasonably available control technology (RACT) for major sources of volatile organic compounds (VOCs) and NOx, and sections 184(b)(1)(B) and 182(f) of the Act require RACT control requirements be adopted in all areas included within the Ozone Transport Region (OTR) established under section 184. Due primarily to the NOx RACT requirement, many states within the Northeast located within the OTR have adopted NOx emission limits for MWCs that are more stringent than what would otherwise be required by EPA's NSPS or emissions guideline for these units. For example, the Montgomery County Resource Recovery Facility in Maryland is required to meet a NOx RACT limit of 140 ppm (@ 7% oxygen) on a 24-hour block average. Additionally, MWC facilities located in Virginia operated by Covanta, Inc., are required to meet a NOx RACT limit of 110 ppm (@ 7% oxygen) on a 24-hour basis, and a limit of 90 ppm (@ 7% oxygen) on an annual average basis.[73]

Emissions and control options outlined within a June 2021 report from the OTC

The OTC issued a report entitled "Municipal Waste Combustor Workgroup Report" in June of 2021. The report is included within the docket for this final rule. The report notes that MWCs are a significant source of NOx emissions in the OTR, releasing approximately 22,000 tons of NOx from facilities within nine OTR states in 2018. The report summarizes the results of a literature review of state-of-the-art NOx controls that have been successfully installed on MWCs 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 emission reduction potential from two different control levels, one based on a NOx concentration in the flue gas 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 ppmvd on a 30-day average basis and a 110 ppmvd on a 24-hour averaging period would reduce NOx 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 tons reduction. The report notes that eight MWC units exist that are already subject to permit limits of 110 ppm, seven in Virginia, and one in Florida. Studies evaluating MWCs similar in design to the large MWCs in the OTR found NOx reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NOx reduced. Based on the findings of this report, the Commissioners of the states within the OTR adopted a resolution to develop a recommendation for emission reductions from MWCs during their June 15, 2021, annual public meeting.[74]

The OTC's MWC workgroup report describes a literature review to identify additional control technologies to reduce NOx emissions from large MWCs. Based on that review, two control technologies emerged as potentially technically and economically feasible options to achieve the control levels of 105 ppm on a 30-day average basis and a 110 ppm on a 24-hour averaging period: Covanta's "Low-NOx (LN™) technology" and advanced selective non-catalytic reduction (ASNCR).

Covanta's LN™ Process

Covanta's LN™ process is a trademarked system which modifies the secondary air (also called overfire air) stream. To complete the combustion process in the MWC furnace, the secondary air is injected through nozzles located in the furnace side walls above the grate to allow turbulent mixing. With the LN™ process, a tertiary air stream is introduced by diverting a portion of secondary air through a new series of air nozzles located higher in the furnace. By controlling the distribution of air between the primary, secondary, and tertiary streams, the optimal gas composition and temperature is achieved to minimize NOx formation. With complete coverage of the furnace cross-section, the tertiary air stream ensures good mixing with

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[73] The NOx 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 action.
[74] See "Notice of Actions Taken by Ozone Transport Commission At Annual Public Meeting, June 15, 2021" included in the Docket for this action.

the combustion gases. During the LN^{TM} process, only the distribution of air is altered. The total air flow to the MWC is left unchanged.

Approximately 20 units have installed or been retrofitted with the LN^{TM} process, including the two Covanta facilities located in Virginia. However, since the LN^{TM} technology is proprietary, it is available only to Covanta facilities at this time (though there may be potential for licensing agreements with other facilities; however, this is beyond the scope of EPA's analysis).

Advanced Selective Non-Catalytic Reduction (ASNCR)

The OTC's MWC report describes a report conducted by Babcock Power for the Wheelabrator Baltimore facility that evaluated several potential NOx control technologies, including ASNCR. ASNCR, like SNCR, involves the injection of reagents (typically ammonia or urea) into the proper temperature zone of the furnace to reduce the NOx concentration within the flue gas. ASNCR also utilizes Computational Fluid Dynamics (CFD) modeling and Chemical Kinetic Modeling (CKM) technology along with real-time furnace temperature maps to modulate which injectors are in operation and the reagent flow rates. This not only significantly decreases NOx emissions but ensures a low ammonia slip (around 5 ppm). ASNCR is currently being installed at Wheelabrator Baltimore and is available to non-Covanta facilities. In addition to the two NOx control technologies described above, the Babcock report also reviewed other NOx control options including optimized SNCR, flue gas recirculation SNCR (FGR-SNCR), and FGR-ASNCR.

OTC Report's Evaluation of Control Costs

The OTC's MWC report also evaluated the cost for the installation and operation of the control technologies. The cost effectiveness for LN^{TM} technology were based off of two RACT analyses by Trinity Consultants for the Covanta Alexandria/Arlington and Covanta Fairfax facilities in Virginia. These reports assessed the total capital investment expenditures for the LN^{TM} technology, which includes direct cost (purchasing the equipment) and indirect costs (installation and lost production resulting from extended downtime due to installation). The costs from the installation of the LN^{TM} technology at the Covanta facility in Montgomery County, MD were used to estimate the costs for Covanta Alexandria/Arlington and Covanta Fairfax. Capital costs were annualized, based on projected lifetime of 20 years and a 7% interest rate, and added to the annual operating cost to determine the total yearly costs.[75]

Although the Trinity Consultants reports assumed a controlled NOx value of 90 ppm (the new annual NOx limit at the two Virginia facilities), the OTC's MWC workgroup estimated the cost reduction for a 110 ppm 24-hour limit. This was done because the amount of reagent used and operations and maintenance costs are likely to be higher to achieve a 90 ppm limit, as compared to a 110 ppm 24-hour limit. This resulted in a price decrease of $0.89 per pound of NOx reduced, per information contained in the Babcock report for the Wheelabrator Baltimore facility.

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[75] We note that the analysis referenced in the OTC's MWC report did not specify the dollar year for the total yearly costs, nor for the cost per ton NOx reduced estimates.

The OTC's MWC workgroup then calculated the projected NOx emission reduction based on a 110 ppm limit. To determine the cost effectiveness, the total yearly costs were divided by the NOx emission reduction. Overall, the 110 ppm 24-hour NOx limit cost effectiveness for LN^{TM} technology ranged from $2,900 to $4,639 per ton of NOx reduced.

The OTC's MWC report also evaluated the cost effectiveness of ASNCR to control NOx emissions at MWCs. Cost effectiveness calculations for ASNCR were based off the Babcock report. To evaluate the annualized capital cost, the workgroup utilized a formula from EPA Air Pollution Control Cost Manual and its *Chapter 2 – Cost Estimation: Concepts and Methodology* (US EPA, 2017). Like the Trinity Consultants RACT analyses, a projected lifetime of 20 years and a 7% interest rate were assumed to estimate the annualized capital cost. Also, as with the LN^{TM} technology, the NOx emission reduction for ASNCR was based on a 110 ppm 24-hour limit. For ASNCR, the 110 ppm 24-hour NOx limit cost effectiveness was $6,159 per ton of NOx reduced.

Evaluation of Cost Controls

Based on our review of available information as described above, the final NOx emission limit for municipal solid waste combustors is 105 ppm on a 30-day average basis and a 110 ppm on a 24-hour averaging period. A number of NOx control technologies exist that should enable most facilities to meet these emission limits, and numerous examples exist of states that have already adopted emission limits similar to EPA's final emissions limits. The OTC report, outlined above, suggests that Covanta's "Low-NOx (LN^{TM}) technology" and advanced selective non-catalytic reduction (ASNCR) are both technically and economically feasible options to achieve the control levels of 105 ppm on a 30-day average basis and a 110 ppm on a 24-hour averaging period.

In order to derive a more case-specific cost effectiveness value for the units subject to this rule, we used the cost effectiveness values estimated in the OTC's MWC report and the data we have on currently installed NOx controls to come up with cost estimates based on the controls we expect facilities to install to meet the final NOx emissions limit (see Table 9).
Given that the LNTM technology is proprietary and therefore, as far as the Agency currently understands, available only to Covanta facilities, we assumed installation of this technology only at Covanta facilities. For all other facilities, we assumed installation or retrofitting of ASNCR. Using the control technology costs outlined in the OTC report, we derived four different annual cost estimates for four different control technology installation scenarios:

1. For units expected to install ASNCR:
    a. The OTC Report cited $1,812,930 in total yearly costs (operating and capital) for installing ASNCR for an MWC with 3 incinerators. Based on this information, we used $604,310 for ASNCR being installed on each incinerator at an MWC.

2. For units expected to install LNTM:
    a. The OTC Report cited total yearly cost (operating and capital) for 1 incinerator ranging from $297,679 to $580,181. Based on this information, we conservatively

assumed $580,181 for any incinerator type that Covanta has indicated can install Low NOx Burners and SNCR.

3. For units that already have ASNCR installed:
    a. The OTC Report cited $995,000 for the annual operating costs of an ASNCR at an MWC with 3 incinerators. Since these facilities already have ASNCR installed, we did not include the capital costs. Based on this information, we used $331,667 for the operating costs of an ASNCR on each incinerator to meet the 110 ppm emission limit.
    b. This estimate is conservative since these units are already operating the installed ASNCR at a lower reagent usage and so are already paying a portion of the $331,667 annual operating costs.

4. For units that already have LNTM and SNCR installed:
    a. Report cited annual operating cost for 1 incinerator ranging from $181,146 to $401,243. Since these facilities already have Low NOx Burners and SNCR installed, we did not include the capital costs. Based on this information we conservatively assumed $401,243 for the additional operating costs to meet the 110 ppm emission limit.
    b. This estimate is also conservative since these units are already operating the installed Low Nox and SNCR at a lower reagent usage and so are already paying a portion of the $401,243 annual operating costs.

We applied these annual costs to the expected emissions reductions resulting from the 110 ppm emissions limit and determined that the estimated weighted average cost per ton across the facilities subject to this rule is $8,323.62.

Table 7.B: MWC Control Costs

State	Site Name	NOx Limit (ppmvd)	% Reduction	NOx Emissions (tons)	Emissions Reductions (tons)	Current Nox Controls	Controls Expected to be Installed
CA	Covanta Stanislaus Energy	165	33%	145.07	48.36	SNCR	ASNCR
CA	Covanta Stanislaus Energy	165	33%	145.07	48.36	SNCR	ASNCR
CA	Long Beach City, Serrf Project	205	46%	84.98	39.38	LN_{tm} +SNCR	None
CA	Long Beach City, Serrf Project	205	46%	87.45	40.53	LN_{tm} +SNCR	None
CA	Long Beach City, Serrf Project	205	46%	96.03	44.50	LN_{tm} +SNCR	None
IN	Covanta Indianapolis Inc	205	46%	350.41	162.38	SNCR	ASNCR
IN	Covanta Indianapolis Inc	205	46%	381.16	176.64	SNCR	ASNCR
IN	Covanta Indianapolis Inc	205	46%	390.50	180.96	SNCR	ASNCR
MD	Montgomery County Rrf	140	21%	150.08	32.16	LN_{tm} +SNCR	None
MD	Montgomery County Rrf	140	21%	153.28	32.85	LN_{tm} +SNCR	None
MD	Montgomery County Rrf	140	21%	166.55	35.69	LN_{tm} +SNCR	None
MD	Wheelabrator Baltimore, Lp	150	27%	305.44	81.45	ASNCR	None
MD	Wheelabrator Baltimore, Lp	150	27%	307.53	82.01	ASNCR	None
MD	Wheelabrator Baltimore, Lp	150	27%	310.75	82.87	ASNCR	None
MI	Kent County Waste To Energy Facility	205	46%	153.22	71.01	SNCR	ASNCR
MI	Kent County Waste To Energy Facility	205	46%	153.60	71.18	SNCR	ASNCR
NJ	Covanta Warren Energy Resource Co. L.P.	150	27%	12.19	3.25	SNCR	LN_{tm} +SNCR
NJ	Covanta Warren Energy Resource Co. L.P.	150	27%	12.19	3.25	SNCR	LN_{tm} +SNCR
NJ	Camden County Energy Recovery Associates L.P.	150	27%	103.76	27.67	SNCR	ASNCR
NJ	Camden County Energy Recovery Associates L.P.	150	27%	103.76	27.67	SNCR	ASNCR
NJ	Camden County Energy Recovery Associates L.P.	150	27%	103.76	27.67	SNCR	ASNCR
NJ	Wheelabrator Gloucester Company Lp	150	27%	112.94	30.12	SNCR	ASNCR

State	Site Name	NOx Limit (ppmvd)	% Reduction	NOx Emissions (tons)	Emissions Reductions (tons)	Current Nox Controls	Controls Expected to be Installed
NJ	Wheelabrator Gloucester Company Lp	150	27%	112.94	30.12	SNCR	ASNCR
NJ	Union County Resource Recovery Facility	150	27%	217.05	57.88	SNCR	ASNCR
NJ	Union County Resource Recovery Facility	150	27%	217.05	57.88	SNCR	ASNCR
NJ	Union County Resource Recovery Facility	150	27%	217.05	57.88	SNCR	ASNCR
NJ	Covanta Essex Company	150	27%	268.30	71.55	LN_{tm} +SNCR	None
NJ	Covanta Essex Company	150	27%	268.30	71.55	LN_{tm} +SNCR	None
NJ	Covanta Essex Company	150	27%	268.30	71.55	LN_{tm} +SNCR	None
NY	Babylon Resource Recovery Facility	150	27%	92.61	24.70	SNCR	ASNCR
NY	Babylon Resource Recovery Facility	150	27%	92.61	24.70	SNCR	ASNCR
NY	Wheelabrator Hudson Falls	150	27%	113.46	30.26	none	ASNCR
NY	Huntington Resource Recovery Facility	150	27%	119.50	31.87	SNCR	ASNCR
NY	Huntington Resource Recovery Facility	150	27%	119.50	31.87	SNCR	ASNCR
NY	Huntington Resource Recovery Facility	150	27%	119.50	31.87	SNCR	ASNCR
NY	Wheelabrator Hudson Falls	150	27%	129.54	34.54	none	ASNCR
NY	Onondaga Co Resource Recovery Facility	150	27%	191.03	50.94	SNCR	ASNCR
NY	Onondaga Co Resource Recovery Facility	150	27%	191.03	50.94	SNCR	ASNCR
NY	Onondaga Co Resource Recovery Facility	150	27%	191.03	50.94	SNCR	ASNCR
NY	Wheelabrator Westchester Lp	150	27%	319.47	85.19	SNCR	ASNCR
NY	Wheelabrator Westchester Lp	150	27%	350.29	93.41	SNCR	ASNCR
NY	Covanta Niagara Lp	150	27%	341.73	91.13	SNCR	LN_{tm} +SNCR
NY	Wheelabrator Westchester Lp	150	27%	373.75	99.67	SNCR	ASNCR

State	Site Name	NOx Limit (ppmvd)	% Reduction	NOx Emissions (tons)	Emissions Reductions (tons)	Current Nox Controls	Controls Expected to be Installed
NY	Covanta Niagara Lp	150	27%	378.41	100.91	SNCR	LN_{tm} +SNCR
NY	Hempstead Resource Recovery Facility	185	41%	346.88	140.63	SNCR	ASNCR
NY	Hempstead Resource Recovery Facility	185	41%	346.88	140.63	SNCR	ASNCR
NY	Hempstead Resource Recovery Facility	185	41%	346.88	140.63	SNCR	ASNCR
OK	Walter B Hall Resource Recovery Facility	205	46%	146.26	67.78	SNCR	ASNCR
OK	Walter B Hall Resource Recovery Facility	205	46%	185.95	86.17	SNCR	ASNCR
OK	Walter B Hall Resource Recovery Facility	205	46%	186.26	86.31	SNCR	ASNCR
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	150	27%	55.80	14.88	SNCR	ASNCR
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	150	27%	66.30	17.68	SNCR	ASNCR
PA	Lancaster Cnty Swma/Susq Resource Mgmt Complex	150	27%	67.60	18.03	SNCR	ASNCR
PA	York Cnty Solid Waste/York Cnty Resource Recovery	135	19%	143.70	26.61	SNCR	ASNCR
PA	York Cnty Solid Waste/York Cnty Resource Recovery	135	19%	152.00	28.15	SNCR	ASNCR
PA	York Cnty Solid Waste/York Cnty Resource Recovery	135	19%	156.30	28.94	SNCR	ASNCR
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	148.04	57.57	SNCR	ASNCR
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	163.17	63.45	SNCR	ASNCR
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	163.27	63.49	SNCR	ASNCR
PA	Lancaster Cnty Rrf/ Lancaster	180	39%	172.55	67.10	SNCR	ASNCR
PA	Lancaster Cnty Rrf/ Lancaster	180	39%	176.11	68.49	SNCR	ASNCR

State	Site Name	NOx Limit (ppmvd)	% Reduction	NOx Emissions (tons)	Emissions Reductions (tons)	Current Nox Controls	Controls Expected to be Installed
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	179.06	69.63	SNCR	ASNCR
PA	Lancaster Cnty Rrf/ Lancaster	180	39%	181.76	70.68	SNCR	ASNCR
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	185.12	71.99	SNCR	ASNCR
PA	Covanta Delaware Valley Lp/Delaware Valley Res Rec	180	39%	191.95	74.65	SNCR	ASNCR
PA	Wheelabrator Falls Inc/Falls Twp	150	27%	293.45	78.25	SNCR	ASNCR
PA	Wheelabrator Falls Inc/Falls Twp	150	27%	305.81	81.55	SNCR	ASNCR
PA	Covanta Plymouth Renewable Energy/ Plymouth	180	39%	273.92	106.53	SNCR	ASNCR
PA	Covanta Plymouth Renewable Energy/ Plymouth	180	39%	283.20	110.13	SNCR	ASNCR
VA	Wheelabrator Portsmouth	250	56%	232.14	130.00	none	ASNCR
VA	Wheelabrator Portsmouth	250	56%	261.26	146.31	none	ASNCR
VA	Wheelabrator Portsmouth	250	56%	261.34	146.35	none	ASNCR
VA	Wheelabrator Portsmouth	250	56%	297.56	166.63	none	ASNCR
VA	Covanta Alexandria/Arlington Inc	110	0%	151.79	0.00	LN_{tm} +SNCR	None
VA	Covanta Alexandria/Arlington Inc	110	0%	145.20	0.00	LN_{tm} +SNCR	None
VA	Covanta Alexandria/Arlington Inc	110	0%	152.39	0.00	LN_{tm} +SNCR	None
VA	Covanta Fairfax Inc	110	0%	508.02	0.00	LN_{tm} +SNCR	None
VA	Covanta Fairfax Inc	110	0%	514.69	0.00	LN_{tm} +SNCR	None
VA	Covanta Fairfax Inc	110	0%	506.39	0.00	LN_{tm} +SNCR	None
VA	Covanta Fairfax Inc	110	0%	453.32	0.00	LN_{tm} +SNCR	None

Compliance Assurance Requirements

MWCs subject to the emissions limits will be required to demonstrate compliance in a manner similar to the NSPS requirements for large MWCs under 40 CFR part 60, subpart Eb. Those requirements include, among other provisions, the performance of an initial performance test and installation of a CEMS.

The final rule provides that, during periods of startup and shutdown, CEMS data is not required to be corrected to 7 percent oxygen and is to be measured at stack oxygen content. This approach is consistent with how EPA has addressed startup and shutdown for other solid-waste incinerators under the Commercial and Industrial Solid Waste Incineration Units rules. *See* 40 CFR part 60, subparts CCCC and DDDD.

We analyze here whether it would be appropriate to apply this provision in this action. EPA has identified the following seven specific criteria as appropriate considerations for developing emission limitations in SIP provisions that apply during startup and shutdown:[76]

(1) The revision is limited to specific, narrowly defined source categories using specific control strategies (*e.g.,* cogeneration facilities burning natural gas and using selective catalytic reduction);
(2) Use of the control strategy for this source category is technically infeasible during startup or shutdown periods;
(3) The alternative emission limitation requires that the frequency and duration of operation in startup or shutdown mode are minimized to the greatest extent practicable;
(4) As part of its justification of the SIP revision, the state analyzes the potential worst-case emissions that could occur during startup and shutdown based on the applicable alternative emission limitation;
(5) The alternative emission limitation requires that all possible steps are taken to minimize the impact of emissions during startup and shutdown on ambient air quality;
(6) The alternative emission limitation requires that, at all times, the facility is operated in a manner consistent with good practice for minimizing emissions and the source uses best efforts regarding planning, design, and operating procedures; and
(7) The alternative emission limitation requires that the owner or operator's actions during startup and shutdown periods are documented.

This rulemaking addresses these seven criteria for emission limitations that apply during startup and shutdown for Large MWCs in the following ways:

(1) The revision is limited to specific, narrowly defined source categories using specific control strategies (*e.g.,* cogeneration facilities burning natural gas and using selective catalytic reduction):

Beginning with the 2026 ozone season and in each ozone season thereafter, emissions limits of 110 ppmvd at 7 percent oxygen on a 24-hour averaging period and 105 ppmvd at 7 percent oxygen on a 30-day averaging period will apply to new or existing municipal waste combustor units with a combustion capacity greater than 250 tons per day (225 megagrams per

[76] 80 Fed. Reg. at 33912.

day) of municipal solid waste 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).

Of the 80 MWC units that will be subject to this rule, 55 units have SNCR installed, 16 units have SNCR and low NOx technology installed, three units have ASNCR installed, and 6 have no control technology installed.

(2) Use of the control strategy for this source category is technically infeasible during startup or shutdown periods:

The final rule sets NOx 24-hour block average and 30-day rolling average emission rates corrected to 7% oxygen concentration, to be met at all times except for periods of startup and shutdown.[77] The 24-hour block average and 30-day rolling average emission rates are steady state (normal operation mode) emission limits in parts per million by volume (ppmv), which is a measure of concentration. This concentration measurement is calculated as mass of NOx emitted/volumetric gas flow rate from the stack.

The 24-hour block average and 30-day rolling average emission rates for MWCs are defined as a value of NOx emissions in ppmv, corrected to 7 percent oxygen. Therefore, the 24-hour block average and 30-day rolling average emission rates are mathematically adjusted so that the volumetric gas flow rate from the stack is corrected to 7 percent oxygen. Concentration-based emission limits are not practical during startup and shutdown because it is technically infeasible for MWCs to comply with the emission rates due to the "7 percent oxygen correction factor" that is required to be applied to the NOx 24-hour block average and 30-day rolling average emission rates. During periods of startup and shutdown, the volumetric gas flow rate from the stack is transient, as adjustments are made to the amount of air introduced into the furnace. The mathematical oxygen correction would result in an artificially high NOx "concentration reading," even though the amount (mass) of actual NOx emissions would remain unchanged during startup or shutdown. Therefore, it is necessary to set alternative NOx emission limits based on mass of NOx emitted during periods of startup and shutdown (transient periods). Under the final rule, during startup and shutdown, MWCs must continue meeting 110 ppmvd the 24-hour block average and the 105 ppmvd 30-day rolling average emissions limits without correcting emissions to 7% oxygen.

(3) The alternative emission limitation requires that the frequency and duration of operation in startup or shutdown mode are minimized to the greatest extent practicable:

Under the final rule, the duration of startup and shutdown procedures for large MWC units are not to exceed three hours per occurrence, which minimizes the duration of the startup or shut down to the greatest extent practicable. Additionally, unit owner and operators are economically motivated to minimize the duration of any startups since the shorter the startup the quicker a unit can be brought online to sell steam and/or connect to the grid and sell power.

[77] Beginning with the 2026 ozone season and in each ozone season thereafter.

(4) As part of its justification of the SIP revision, the state analyzes the potential worst-case emissions that could occur during startup and shutdown based on the applicable alternative emission limitation:

As an example of worse case emissions from a unit subject to this rule, see the equations below. These calculations assume that the stack oxygen concentration reaches atmospheric conditions of 20.9 during startup and shutdown. As a representation of worse case emissions, the calculations below use information available on the Wheelabrator Baltimore facility, which demonstrated an oxygen concertation of 10.7% and average flue gas flow of 106,336 dscf/min during the 2017 stack test.[78]

Normal operations mass emissions when meeting the 110 ppmvd at 7% oxygen concentration on a 24-hour block average:

$$110\ ppmvd \text{ x } \frac{20.9 - 10.7}{20.9 - 7} \text{ x } (1.194 \text{ x } 10^{-7}) \text{ x } 106{,}336 \frac{\text{dscf}}{\text{min}} \text{ x } 60 \frac{\text{min}}{\text{hour}} = 61.6 \frac{\text{lb}}{\text{hr}}$$

Startup and shutdown emissions assuming ambient oxygen concentration assuming the unit is emitting 110 ppmvd at 20.9% oxygen:

$$110\ ppmvd \text{ x } \frac{20.9}{20.9} \text{ x } (1.194 \text{ x } 10^{-7}) \text{ x } 106{,}336 \frac{\text{dscf}}{\text{min}} \text{ x } 60 \frac{\text{min}}{\text{hour}} = 83.8 \frac{\text{lb}}{\text{hr}}$$

While EPA expects an increase in emissions during startup and shutdown in situations like this, the 3-hour limitation for startup and shutdowns sufficiently minimize emissions.

(5) The alternative emission limitation requires that all possible steps are taken to minimize the impact of emissions during startup and shutdown on ambient air quality:

The final rule does not provide any exclusions from operating controls. MWCs must follow the same emission reduction practices as during normal operation, including operating their ASNCR or low-NOx burners and SNCR during startup and shutdown. In order to meet the final emissions limits for startup and shutdown, MWCs must meet the same emissions limits as normal operations expect that they are not required to correct CEMS data to 7% oxygen. During startup and shutdown, increased gas flow rates into the furnace result in higher oxygen contents in the stack; however, it will still be necessary for these MWCs to operate their controls in order to achieve the NOX control technology to achieve the 110 ppmvd on a 24-hour block average and 105 on a 30-day rolling average.

(6) The alternative emission limitation requires that, at all times, the facility is operated in a manner consistent with good practice for minimizing emissions and the source uses best efforts regarding planning, design, and operating procedures:

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[78] Maryland Department of Environmental Protection, *Technical Support Document for Amendments to COMAR 26.11.08 – Control of Incinerators*, at 30-31 (September 25, 2019).

In addition to the necessity for controls to be run in order to achieve the emissions limits in the final rule, the final rule includes a requirement for owners and operators to minimize emissions by operating their controls, follow good combustion practices and manufacturer's specifications. Specifically, the final rule requires, at 40 CFR 52.46(d)(5), that:

> The owner and operator of an affected unit shall minimize NOx emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR § 60.11(d)) for such equipment and the unit at all times the unit is in operation.

(7) The alternative emission limitation requires that the owner or operator's actions during startup and shutdown periods are documented:

The final rule requires that sources keep CEMS records demonstrating compliance with the emissions limits and requires records to be kept of the steps taken to minimize emissions as required by 40 CFR 52.46(d)(5).

NOx Emission Control Technology Installation Timing for Non-EGU Sources

Final Report

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DISCLAIMER

This report presents the results of SC&A's research on questions pertaining to control installation timing needs for industrial sources covered by the EPA's Good Neighbor Federal Implementation Plan (FIP) for the 2015 ozone NAAQS. The report includes summaries of comments regarding control installation timing needs that the EPA received during the public comment period and information obtained by SC&A or the EPA from control technology vendors, state permitting staff, and other entities, but it does not necessarily endorse or adopt the views of these commenters or other entities. Additionally, although statements by individual state permitting staff and control-installation vendors have been documented accurately and reflect these individuals' or entities' experiences and expertise, SC&A was not able to independently verify or substantiate these statements in the time provided.

The information presented in this report regarding the potential for supply-chain delays reflects current economic conditions (that is, conditions as of 2022) and current constraints on manufacturing capacity and skilled labor relevant to pollution control installation. The report discusses to some extent whether these conditions may be anticipated to continue into the future by considering several current economic indicators, but because of a lack of information available to SC&A it does not project key economic indicators that may be relevant to NOx control installation timing estimates for industries affected by this final rule. Although the information presented in this report informed the EPA's evaluation of the installation timing issues raised during the public comment period on the Good Neighbor FIP, this report does not necessarily reflect the views of the EPA or EPA staff and does not constitute EPA endorsement of any of the conclusions herein. This report does not supply facility-specific information that would be relevant or reliable in any future determination of necessity for additional time, on a source-specific basis, to come into compliance with any Clean Air Act requirement.

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ACRONYMS

ABC	Associated Builders and Contractors
AF&PC	Arkansas Forest & Paper Council
AISI	American Iron and Steel Institute
ASNCR	advanced selective noncatalytic reduction
BF	blast furnace
BLS	Bureau of Labor Statistics
BOF	basic oxygen furnace
BTS	Bureau of Transportation Statistics
Btu	British thermal unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBI	Construction Backlog Indicator
CEM	Continuous Emissions Monitor
CIBO	Council of Industrial Boiler Owners
CO	carbon monoxide
CO_2	carbon dioxide
EAF	electric arc furnace
EGU	electricity generating unit
EPA	United States Environmental Protection Agency
EPC	engineering, procurement, and construction
ESP	electro-static precipitator
FERC	United States Federal Energy Regulatory Commission
FGR	flue gas recirculation
FIP	Federal Implementation Plan
FTE	full-time equivalent
g	gram
hp	horsepower
hr	hour
ICAC	Institute of Clean Air Companies
ICI	industrial/commercial/institutional
IMA-NA	Industrial Minerals Association – North America
INGAA	Interstate Natural Gas Association of America
IR	ignition timing retard
lb	pound
LC	layered combustion
LDC	local distribution company
LDEQ	Louisiana Department of Environmental Quality
LEC	low emissions combustion
LMF	ladle metallurgy furnace
LNB	low NOx burner
LN^{tm}	Covanta Patented Low NOx Technology
m	meter
m^3	cubic meters

MMBtu	million British thermal units
MRRA	Minnesota Resource Recovery Association
MSW	municipal solid waste
MW	megawatt
MWC	municipal solid waste combustor
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NETL	National Energy Technology Labs
NGR	natural gas reburn
NNSR	nonattainment new source review
NSCR	non-selective catalytic reduction
NSR	New Source Review
non-EGU	non-electric generating unit
NOx	Nitrogen oxides
OEAS	oxygen enriched air staging
OEM	original equipment manufacturer
OFA	overfire air
ppb	parts per billion
ppmvd	parts per million by volume, dry
PM	particulate matter
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RDF	refuse-derived fuel
RFP	request for proposal
RFQ	request for quotation
RICE	reciprocating internal combustion engine
SMA	Steel Manufacturing Association
SSINA	Specialty Steel Industry of North America
SWANA	Solid Waste Association of North America
TCEQ	Texas Commissions on Environmental Quality
tpy	tons per year
TSD	Technical Support Document
SCD	supply chain delay
SCR	selective catalytic reduction
SNCR	selective noncatalytic reduction
ULNB	ultra-low NOx burner
USLM	U.S. Lime & Minerals
VOC	volatile organic compound
WPC	Wisconsin Paper Council

Executive Summary

The United States Environmental Protection Agency (EPA) proposed a "Good Neighbor" Federal Implementation Plan (FIP) to address regional ozone transport for the 2015 ozone National Ambient Air Quality Standard (NAAQS), which published in the Federal Register on April 6, 2022.[1] This proposed rule identified proposed oxides of nitrogen (NOx) emission limits for certain industrial stationary sources in states that were determined by EPA to be impacting the ability of downwind states to meet the ozone NAAQS.[2] The objective of this report is to provide EPA with information on the amount of time needed for non-electricity generating units (non-EGUs) in the specified industries to install the NOx control technologies necessary to comply with the requirements of the final FIP.

To address the timing needs for installation of NOx emission controls in the non-EGU sectors covered by the rule, the EPA enlisted SC&A, Inc. (SC&A) to examine a number of issues. These include:

- The time required to install NOx controls on affected NOx emission sources;
- The time required for state permitting staff to process permit modifications required for compliance with the final rule;
- Constraints on skilled labor relevant to air pollution control installation; and
- Supply chain constraints.

These issues are summarized below.

<u>Summary of Overall Control Installation Timing and Permit Processing Time Estimates</u>

Based on our findings drawn from information taken from a variety of sources as discussed later in this report, Table ES-1 provides a summary of the estimated range of calendar months needed for affected sources to complete all phases of NOx control installation (design, engineering, vendor selection, permitting, equipment fabrication, and control installation). These sources include prior technical studies, comments received on the proposed FIP, and control equipment vendor contacts. Two timelines are presented in Table ES-1 – the "Estimated Install Timeline" and the "Supply Chain Delay (SCD) Install Timeline."

- The "Estimated Install Timeline" – This timeline does not factor in any supply chain or other delays. It should be understood to reflect the amount of time expected to install the control at a single affected unit without any consideration of supply chain delays. Under ideal circumstances, without any supply chain delays, the entire estimated population of affected units could be addressed within this timeline. There are situations for some affected units where a single facility has multiple affected units. In those situations, the amount of time per control installation could be reduced. An example is the application of compact SCR at a natural gas compressor station. Where multiple RICE can be addressed at the same time, the amount of calendar time per engine could be reduced (mainly through the time required to issue a single

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[1] EPA, *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Proposed Rule, 87 FR 20036, April 6, 2022.

[2] Updated air quality modeling and analysis by the EPA was completed, and as a result Alabama, Minnesota, and Wisconsin will not be subject to non-EGU control requirements in the final FIP rulemaking. EPA is not finalizing a FIP for Tennessee or Wyoming at this time. Also, while Nevada is still included for non-EGU requirements, no existing affected industrial units under the final FIP were identified by EPA.

air permit modification for all affected RICE at the station). Sufficient data were not available to conduct case-by-case assessments of where such situations might arise.

- SCD Install Timeline -- In situations where supply chain delays are expected, based on current economic conditions and capacities (that is, as of 2022), a separate set of estimates incorporates our best estimates of the length of such delays ("SCD Install Timeline"). These estimates should be understood to reflect not only economic conditions and capacities as of 2022 but also the time required to address the entire population of affected units, if these supply chain delays were to continue unabated into the future. However, as noted later in the report, the most recent economic data tend to indicate that supply chain disruptions observed in the 2020-2022 timeframe associated with the pandemic and the war in Ukraine may already be lessening.

In cases where the timeline in both the "Estimated Install Timeline" and "SCD Install Timeline" columns is the same, there is no significant supply chain delay that results in a change to the initial "Estimated Install Timeline." In other words, in these cases, it would be possible for all units to be controlled in the same timeframe as a single unit.

The NOx controls represented in Table ES-1 are low NOx burners (LNB), selective catalytic reduction (SCR); selective non-catalytic reduction (SNCR); non-selective catalytic reduction (NSCR); low NOx burner and flue gas recirculation (LNB + FGR); Covanta's patented Low NOx Technology (LN^{tm}) + SNCR; and advanced selective noncatalytic reduction (ASNCR).

Table ES-1. Estimated Time Required to Achieve All Phases of NOx Control of Non-EGUs

Industry	Emissions Source Group	Control Technology	Estimated Installs	Estimated Install Timeline (months)[a]	SCD Install Timeline (months)[a]
Cement and Concrete Product Manufacturing	Kilns	SNCR	16	17 - 24	35 - 58
Glass and Glass Product Manufacturing	Melting Furnaces	LNB	61	9 - 15	9 - 15
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	19	9 - 15	9 - 15
Pipeline Transportation of Natural Gas[b]	RICE 2-Cycle	Layered Combustion	394	6 - 12	40 – 72*
Pipeline Transportation of Natural Gas[b]	RICE 4-Cycle Rich Burn	NSCR	30	6 - 12	6 - 12

Industry	Emissions Source Group	Control Technology	Estimated Installs	Estimated Install Timeline (months)[a]	SCD Install Timeline (months)[a]
Pipeline Transportation of Natural Gas[b]	RICE unspecified	NSCR or Layered Combustion	323	6 - 12	40 – 72*
Pipeline Transportation of Natural Gas[b]	RICE 4-Cycle Lean Burn reciprocating	SCR	158	10 - 19	10 - 19
Affected Non-EGU Industries[c]	Boilers	LNB + FGR	151	9 - 15	9 - 15
Affected Non-EGU Industries[c]	Boilers	SCR	15	14 - 25	26 - 37
Municipal Waste Management	MWC Boilers	LN[tm] + SNCR	4	22 - 28	22 - 28
Municipal Waste Management	MWC Boilers	ASNCR	57	17 - 23	35 - 57

***** We note that the 72-month estimates reflect an upper-bound assumption relating to how many potentially affected engine units are old enough to necessitate specialized labor, which is currently (as of 2022) found to be in limited supply. Further caveats associated with these estimates are discussed elsewhere in the report.

Timeframe for Permitting Processes

In general, we estimate that any permit needed for control installations at an individual source can be issued within a few weeks or months for minor modifications, and within a year for control installations that trigger major modification permitting requirements. For certain states with large numbers of affected sources, there could be a need for additional time, up to a year, to issue necessary permits, e.g., if state resource levels remain unchanged and the state lacks expedited permitting processes. In all cases, any necessary permitting should be complete within a two-year timeframe, and other aspects of control installation can likely proceed to some extent in tandem with the permitting process. We have not added time needed for issuance of permits onto the SCD install timeline because, in the event that supply-chain delays extend the installation timeframe beyond the 3-year period leading to 2026, the permitting process likely would not impact that installation timeframe, as permitting can occur within this timeframe and any potential supply chain delays should not delay the permitting process.

Some state permitting authorities may have a larger permit modification labor burden than others. This is due to both the estimated number of EGU and non-EGU affected units in their jurisdiction as well as the type of permit modifications that may be needed. Major modifications at existing sources are those that would increase emissions by “significant” amounts and thus trigger Prevention of Significant Deterioration (PSD) or Nonattainment New Source Review (NNSR) requirements. Large add-on controls, like SCR or SNCR, may in some cases require PSD or NNSR permits. We anticipate that most control installations will not result in significant emissions increases and thus will require only minor permit modifications, if any. For purposes of this analysis, however, we conservatively assume that all SCR/SNCR installations will require major permit modifications.

The estimated non-EGU NOx controls for the final FIP are divided into two groups. The SCR/SNCR group are all non-EGU applications for these controls, except for compact SCR systems applied to reciprocating internal combustion engines (RICE). The "other NOx controls" category represents mainly combustion controls (e.g., LNB, layered combustion) or packaged post-combustion controls (e.g., NSCR, compact SCR). There will be approximately three years available to achieve compliance with the final FIP, once the final rule is issued. To allow for sufficient time for control design, fabrication and installation, construction permits may need to be processed within the first 18 to 24 months.

Table ES-2 provides a breakdown of the number of affected units by state to identify the states that may have larger numbers of permit modifications to process.[3]

Permitting backlogs are more likely in the states indicated in Table ES-2 with significant numbers of affected units. The states with highlighted cells in Table ES-2 are those that may need to process many major permit modifications (>20) or many minor modifications (>80) within the first two years following rule finalization (this timeframe is expected in order to allow sufficient time for control installation). The presence of an expedited permit review program should help alleviate a significant short-term increase in state permitting review manpower needs in Indiana, Louisiana, and Texas.

Table ES-2. EGU and Non-EGU NOx Control Installations by State

State (Expedited Program?)	Estimated Non-EGU Control Installations		
	SCR / SNCR	Other NOx Controls	Total
Arkansas (N)	2	32	34
California (Y)	6	7	13
Illinois (Y)	8	53	61
Indiana (Y)	12	41	53
Kentucky (Y)	2	46	48
Louisiana (Y)	25	174	199
Maryland (N)	0	2	2
Michigan (N)	16	45	61
Mississippi (N)	6	57	63
Missouri (N)	1	39	40
New Jersey (N)	10	1	11
New York (N)	19	11	30
Ohio (N)	14	96	110
Oklahoma (N)	72	63	135
Pennsylvania (N)	22	63	85
Texas (Y)	19	158	177
Utah (N)	1	5	6

[3] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

State (Expedited Program?)	Estimated Non-EGU Control Installations		
	SCR / SNCR	Other NOx Controls	Total
Virginia (N)	8	29	37
West Virginia (N)	5	58	63
Totals	**248**	**980**	**1,228**

In addition, there may be states where permitting staff resources are stressed by a combination of EGU and non-EGU permit modifications, although through 2026, the EGU permitting resulting from this rule is expected to be relatively small. However, as indicated by the analysis in Section 4 that included information from state permitting agencies, it is expected that at most the incremental permitting load would be under 3 full-time staff per year in all affected states.

Skilled Labor and Other Supply Chain Constraints

Table ES-1 also provides an indication of whether supply chain issues have the potential to extend the estimated time required for control installations. Potential sources of supply chain delays include: competition for engineering, procurement, and construction (EPC) contractors (associated with large controls, such as SCR or SNCR systems); equipment fabrication; skilled installation labor; local construction labor (again for large control systems); and raw materials.

In the case of raw materials, sufficient availability of SCR catalyst material was identified as a concern during discussions with control equipment vendors. This concern is mainly driven by a potentially significant demand placed on catalyst manufacturers by the expected number of existing EGUs that will elect to optimize their SCR systems by 2026. EPA expects that 229 EGU SCR optimizations will have been conducted by the 2023 ozone season. In addition, as early as the 2026/2027 ozone seasons, EPA also projects that a small number of EGUs will retrofit SCR (new system installs) on 2.5 – 8 GW (approximately 16 EGUs assuming a 500 MW unit capacity).[4] EGU SCR "optimizations" cover an array of operational or physical alterations:

- Operational optimizations: these can be made without any physical alterations to the source or SCR system or routine catalyst change-out schedules and include increasing maintenance, optimizing reagent injection, or changing combustion conditions to assure that the exhaust is meeting optimal temperatures for the SCR system (e.g., assuring that the EGU's dispatch schedule maintains adequate exhaust temperature);
- Physical optimizations: these include a complete change-out of catalyst material or the addition of another catalyst layer.

Depending on the number of EGU operators that elect physical optimizations to their SCR systems, a short-term spike in demand for catalyst material could be a concern. However, EPA expects that very few EGU operators will elect to conduct physical optimizations. Of the 229 EGUs noted earlier that could

[4] U.S. EPA, "EGU NOx Mitigation Strategies Final Rule TSD," Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668, March 2023.

optimize their SCRs, 139 of them would have optimizations with emission reductions of 10 tons or less. Also, 191 of the 229 EGUs that could optimize their SCRs (or 83%) are combined cycle and combustion turbines. These natural gas-fired units generally require far less catalyst than coal-fired EGUs of the same size and avoid many of the challenges created by fly ash, the presence of sulfur trioxide, and other metals in the inlet to the SCR. In general, layers of catalysts can generally be swapped out during routine maintenance shutdowns. While catalyst layers are sometimes changed on a rotating schedule, it would not take significantly more time to swap out the entire amount of catalyst. We were unable to source sufficient information from catalyst suppliers to gauge the significance of these new demands including the potential length of any associated supply chain delay.

However, it is likely the case that any resulting increase in catalyst demand can be met via new production and/or the recycling of catalyst material from retired EGUs equipped with SCR. It can be noted that roughly 24 GW of EGUs with SCR are currently planning to retire (or have retired) between Jan 2021 and May 2026.[5] This would lower demand for catalyst, likely significantly more than any increased demand from EGU SCR optimization or retrofits and the non-EGU new SCR installs addressed in this report. In addition, the catalyst material from these retired units will be available for recycling (reducing the need to source new raw materials).

Descriptions of where supply chain delays are expected, as well as their length, are provided below:

- No expected supply chain delay: for control installations in Table ES-1, where the "SCD timeline" is the same as the "estimated install timeline," the control technology is expected to be readily available or to have a short lead time for design and fabrication (e.g., compact SCR[6] or NSCR applied to RICE; LNB for furnaces in glass and glass products and reheat furnaces in iron and steel). Further, skilled labor for control equipment design and installation is expected to be available to meet the expected demand for services.
- Supply chain delay potential: additional time will likely be needed due to an identified supply chain limitation. Situations where supply chain delays are expected are summarized below along with an estimate of the length of delay:
    - <u>Cement and concrete product manufacturing, kilns installing SNCR for compliance</u>: an estimated 16 units may be competing for SNCR EPC contractors along with MWCs (61 units). Although 36 EGU SNCR optimization projects are expected, as stated previously, these should mostly be able to be handled by in-house personnel. The pool of identified US SNCR vendors is less than 10, and the number of these vendors that actually conducts the design (including modeling), engineering, fabrication, and installation may be no more than half of this (5 vendors). Based on discussions with control equipment vendors, 5 SNCR installation projects per year is a representative annual capacity for each vendor.
    - <u>MWC boilers</u>: these 61 sources are estimated to achieve compliance by applying either LN^{tm} + SNCR or ASNCR. The pool of SNCR EPC contractors will likely be limited to those with boiler expertise in the MWC sector. For the four installations of LN^{tm} + SNCR, these

[5] EPA, "Appendix A: Final Rule State Emission Budget Calculations and Engineering Analytics" (this is a spreadsheet that is an appendix to the Ozone Transport Policy Analysis Final Rule TSD).
[6] Note: compact SCR systems are the same in design as the SCRs applied to RICE in the final rule non-EGU cost analysis.

all involve a single OEM for the original MWC unit (Covanta using their own proprietary technology). Given the lack of competition for these facilities and no other supply chain delays expected, it is assumed that Covanta can address these installations within the required installation timeline.

The 57 expected MWC ASNCR and 16 cement kiln SNCR installations may be competing for the same set of vendors. On-line information suggests that there are 3 to 5 vendors capable of supplying ASNCR technology. The total number of EPC contractors for SNCR is somewhat larger, but, if selected, we expect that those companies would still subcontract to the more limited pool of experienced ASNCR equipment suppliers and installers to complete a total of 73 SNCR or ASNCR installations.

Assuming that initial studies and permitting requires up to 12 months, there are two years available before the compliance deadline of May 2026 for final design, engineering, fabrication, and installation. Discussions with vendors suggest that full capacity is on the order of 5 projects at any one time for most suppliers (five per year). Therefore, 15 to 25 installations could be addressed by the estimated vendor pool per year; or 30 to 50 units within 2 years. This leaves an additional 23 to 43 units that may not be able to be addressed by May 2026 (which could be some combination of cement kiln SNCR or MWC ASNCR installations). If the vendor pool is able to address 15 to 25 units per year, then approximately an additional 18 to 34 months (that is, 23 units/15 units/year x 12 months/year to 43 units/15 units/year x 12 months/year) might be needed to address all affected units. This results in a total supply chain delay timeline of 35 to 58 months (17 to 24 months + 18 to 34 months) for cement installations of SNCR and 35 to 57 months (17 to 23 months + 18 to 34 months, again showing the broadest range of values) for ASNCR installation at MWCs. These timing estimates are based on current vendor capacity, and these estimates will decline if such capacity increases to meet the demand related to SNCR or ASNCR installations.

- Pipeline transportation of natural gas, RICE: application of layered combustion controls to some RICE may involve emissions units that are over 60 years old. Comments received by EPA indicate that while retrofit kits should be available for these RICE, these installations may require skilled labor familiar with these units and the specialized control kits to be applied. A key uncertainty is the number of RICE that might elect to apply these combustion kits versus NSCR or another compliance option (e.g., engine replacement or electrification). EPA's estimates in Table ES-1 above indicate that 394 RICE are estimated to apply layered combustion and 323 RICE are estimated to apply either layered combustion or NSCR. This results in a likely quite high upper range estimate of 717 units that could require specialized labor to address (technicians with the skills to apply layered combustion control kits to older RICE). This is a highly conservative estimate in that we do not have information on the number of older engines (i.e., those approaching 60 years of age or older), and it is likely that a much smaller set of units than the total number of units would undertake these types of control installations. Therefore, this number should be considered an upper bound reflective of the lack of data on engine age. As noted, we have also not attempted to assess whether alternative compliance approaches such as replacement of these engines with newer engines, or an increase in the necessary labor pool, could affect these estimates. Industry comments that reflect actions taken nearly 20 years ago suggest that a skilled labor pool is available to address at most 75 RICE per year. However, as discussed in Section 5, information on the growth of available skilled labor as the RICE population has increased over the last 20 years indicates the potential for retrofit capacity of up to twice that amount (or, 150 RICE per year). Hence, depending on the number of older RICE that industry elects to control with layered combustion, potentially the full amount of time needed to complete installations on all affected units is 717/150 = 4.8 years (58 months). For the portion of RICE estimated to be addressed by either layered combustion or NSCR, if half of the RICE are addressed by layered combustion, this results in a total estimate of 506 units. The total amount of time required to address them by the available skilled labor pool is then 506/150 = 3.3 years (40 months). Given that the total number of RICE that may require retrofits in response to this final rule is estimated at about 905, we estimate that the maximum length of control installation time for all sources in this category may potentially be as long as 905/150 = 72 months.

Note that these estimates do not include any consideration of delays that could occur from review required by the Federal Energy Regulatory Commission (FERC). While this concern was identified by commenters on the proposed rule, we were not able to complete an evaluation of these claims. We note that capacity utilization of compressor stations in the U.S. is about 40%; therefore, the ability to coordinate outages and work with FERC may not present a substantial basis for assuming much if any delay in control installation timing on this basis.
The estimated supply chain delay timeline is expected to range from 40 to 72 months. However, we again emphasize that the upper-bound estimate is unlikely to occur in reality. It assumes that all 717 identified engines are so old that they require specialized labor, that no such engines could be replaced with newer engines due to their age, and that there is no growth beyond 2022 in the pool of specialized labor in response to the rule.

- Affected industries, boilers: For sources that require SCR for compliance, some level of competition for EPC vendors is expected with EGUs that adopt SCR retrofits for compliance. The amount of EGU capacity electing to conduct SCR retrofits is expected to be relatively small (2.5 - 8 GW), and for purposes of this report, are expected to occur during the 2023-2027 timeframe. Finally, SCR EPCs for the EGU sector are generally a different group of vendors than those that serve the non-EGU sector.

  The number of non-EGU boiler SCR installations estimated isn't exceptionally large as indicated in Table ES-1; however, information gathered from vendor contacts indicates continuing delays for equipment fabrication and certain imported components. Overall, a supply chain delay of up to 12 months is likely to persist for affected boilers.

An additional supply chain delay concern is the availability of SCR catalyst material due to overlapping demands with EGU SCR optimizations or retrofits. As addressed above, the number of EGU SCR physical optimizations requiring additional catalyst material is expected to be very small and to be completed by the 2023 ozone season. Recent and ongoing EGU retirements with SCR systems will also reduce demand for catalyst and also provide catalyst material for recycling. Considering only the additional 12 months of supply chain delay related to equipment fabrication, the full amount of time needed for SCR installation at an affected industry boiler could extend to 37 months.

Section 5 of this report provides information from a variety of indicators that offer some insight into the potential for skilled labor and supply chain constraint concerns. We find that in most cases, skilled labor and key materials in the supply chain have become more available than they were in 2020, and even when compared to the concerns noted by commenters. However, the progress that has been made in alleviating supply chain issues may need to be balanced with an understanding of the increased demand for key materials and skilled labor that might result from a requirement to install NOx controls on both EGU and non-EGU sources. Based on these indicators and input from control equipment vendors, access to raw materials (e.g., sheet stainless steel) and key components (e.g., electrical controllers, pumps) has either returned to near pre-pandemic levels or is expected to by early 2023.

Overall Conclusions

Based on the findings summarized above, the following types of affected units may experience difficulty in compliance with the final rule by May 2026:

- Kilns in cement and concrete product manufacturing installing SNCR for compliance: due mainly to limitations in the SNCR vendor pool and the overlapping needs for SNCR vendor support by MWCs and EGUs, an additional 18 to 34 months beyond the ”estimated install timeline” may be needed. The supply chain delay timeline is therefore estimated to range from 35 to 58 months.
- RICE in pipeline transportation of natural gas applying layered combustion controls for compliance: assuming the maximum number of engines that could apply this control are so old that they need to be addressed by a limited pool of skilled labor, there is a potential that all affected units will not be able to achieve compliance by May 2026. The supply chain delay timeline is estimated to range from 40 to 72 months.
- Boilers in affected industries installing SCR for compliance may experience delays in equipment fabrication. The supply chain delay timeline is 26 to 37 months.
- MWCs installing either LN^{tm} + SNCR or ASNCR might be competing for vendors in a limited pool of vendors with expertise in the municipal waste industry and with the application of ASNCR. The supply chain delay timeline is estimated to be 35 to 57 months.

1. Introduction

EPA proposed a FIP to address regional ozone transport for the 2015 ozone NAAQS, published in the Federal Register on April 6, 2022.[7] This proposed rule included provisions to establish emission limits on NOx emitted by certain industrial stationary sources in states that have been determined by EPA to be impacting the ability of downwind states to meet the ozone NAAQS. The objective of this report is to provide EPA with information on the time needed for non-EGU NOx emission sources in the specified industries to install NOx controls that would enable these units to meet the emission limits.

In its proposed rule, EPA proposed that the non-EGU NOx controls should be in place in time for the 2026 ozone season and needed to understand issues that could prevent industries from meeting this important deadline. Therefore, EPA solicited comment on issues related to the timing needed to install these controls, issues of technical feasibility related to installing these controls in the specified industries, and other related topics. This report draws on information provided by commenters in response to the proposed rule as well as additional EPA technical reports, industry information, and information obtained directly via communication with industry and state contacts. This report also addresses updates to the non-EGU analysis for the final rule in terms of the number of units that are likely to need to install pollution controls.

While EPA has prepared similar reports on the timing needed to install NOx control technologies on non-EGU sources, the timing of this proposal introduced issues outside prior analyses and potentially beyond the control of industry. The national and international supply chains have been disrupted first by the Covid-19 pandemic that began in 2020 and then by the Russian invasion of Ukraine beginning in early 2022. These supply chain issues were frequently mentioned in comments received by EPA and have the potential to impact the amount of time it will take for many non-EGU emission sources to install NOx controls. Thus, this report addresses these issues and based on analysis of recent economic information, attempts to put these issues in perspective to estimate any delays that supply chain issues may cause to the processes needed to install NOx controls.

Section 2 of this document provides a brief background on each of the non-EGU industries and the corresponding NOx emission sources that EPA has identified as industries and sources impacting the ability of downwind states to meet the ozone NAAQS. Section 3 briefly describes the NOx control technologies that EPA expects affected non-EGU sources will apply to meet the NOx emission limits in the final rule. Section 4 summarizes the evaluation of the timing needed to install NOx controls on the non-EGU emission sources in these industries, both on an individual basis as well as in combination with the entirety of expected NOx controls for non-EGUs and EGUs combined that would be needed to comply with the final rule. Section 5 discusses some of the potential supply chain issues and provides an evaluation of the current economic factors impacting control installation. Finally, a summary of the results from this report is presented in Section 6.

[7] EPA, *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Proposed Rule, 87FR20036, April 6, 2022.

2. Affected Industries—Emission Sources and Unique Issues

The affected non-EGU industries in the final rule for the FIP are as follows:

- Pipeline Transportation of Natural Gas;
- Cement and Concrete Product Manufacturing;
- Iron and Steel Mills and Ferroalloy Manufacturing;
- Glass and Glass Products Manufacturing;
- Basic Chemical Manufacturing;
- Petroleum and Coal Products Manufacturing;
- Pulp, Paper, and Paperboard Mills;
- Metal Ore Mining; and
- Solid Waste Incinerators and Combustors (indicated as Municipal Waste Combustors (MWCs).

A general overview of the affected non-EGU industries is provided below along with a description of the primary sources of NOx emissions in these industries. The industries for which boilers are the only affected sources are addressed as a group in a separate subsection.

2.1 Cement and Concrete Product Manufacturing

Within the cement and concrete product manufacturing industry, EPA's final rule would apply NOx emission limits to kilns used in the production of clinker (all within North American Industry Classification System (NAICS) code 32731x). Cement clinker is used in producing cement, and is produced by grinding and mixing raw materials, and then heating (calcining) them at high temperatures within a kiln. Clinker is made up of glass-hard, spherically shaped nodules that range from an eighth to two inches in diameter. Limestone and other calcareous materials (calcium carbonate containing substances, including gypsum), sand, clay, shale, and iron ore are key raw materials.[8] Some amount of recycled concrete and other materials may also be used in clinker production (e.g., fly ash, slag).

After the raw materials are ground and mixed, they are fed into a kiln. Clinker production is performed using either a dry or wet process. In a wet process, the dry raw materials are mixed with water to form a slurry. In a dry process, the materials are dried to less than one percent prior to pyroprocessing in the kiln. For some plants using the dry process, an additional pre-calciner kiln is added before the main kiln (calciner) to increase the overall thermal efficiency of the process. Both the pre-calciner and main kilns can be fired on a variety of fuels (gas, liquid or solid) up to 2,700°F. After exiting the kiln, the clinker passes through a clinker cooler, where some thermal energy is recovered to return to the process. The clinker is then ground and mixed with other materials to produce finished cement.[9]

Essentially all the NOx emissions associated with cement manufacturing are attributed to the kilns due to the high process temperatures. The specific types of kilns that produce NOx emissions and that may be affected by the final rule are discussed below.

[8] Shaped by Concrete, Sustainably Producing Concrete, website at https://howcementismade.com/.

[9] Shaped by Concrete, Sustainably Producing Concrete, website at https://howcementismade.com/.

Long Wet Kiln

Long wet kilns transform slurry to clinker. The slurry enters the kiln at room temperature with a moisture content of 40%. Wet kilns must be 200 meters (m) long to allow enough time for evaporation. Long wet kilns are not energy efficient because (1) the high moisture content of the slurry must be evaporated by inefficient heat transfer and (2) the construction and maintenance of such a long kiln. Wet kilns are uncommon today because of their required length and energy demands.[10]

Long Dry Kiln

Long dry kilns transform dry blended materials into clinker. Long dry kilns refer to a dry kiln without a preheater or precalciner, hence why they must be longer. This process is more energy efficient than the long wet kiln because (1) the low moisture content of the material allows for a shorter kiln and (2) less heat transfer energy requirements (i.e., little evaporation necessary).[11]

Preheater Kiln

The preheater kiln preheats the materials before entry to the dry kiln to improve overall thermal efficiency. The purpose is to minimize the latent heat requirement of the kiln. The dry powder concrete material, limestone, and other materials enter at the top of the preheater. A series of four to six cyclones keep the material suspended in the air. Hot gases, typically recycled from the clinker cooler, travel up the preheater kiln and heat the cement materials passing down. This is an efficient means of heat transfer. The preheater kiln decarbonizes 30-40% of the material before entering the dry kiln.[12,13]

Precalciner Kiln

A precalciner kiln preheats the materials before entry to the kiln to improve overall thermal efficiency. The precalciner kiln has an additional burner beyond that used in the preheater kiln. Many designs contain a preheater and precalciner in series for maximum operation efficiency. The materials exit the precalciner kiln and enter the dry kiln at approximately 1,700°F. This additional process allows for 85-95% decarbonization of the material before it enters the kiln.[14] In a preheater/precalciner setup, fuel is fired in the precalciner and rotary kiln. Conventional kilns only use fuel within the dry or wet kiln. This unique design of preheater/precalciner systems allows for a shorter dry kiln, in comparison to conventional kilns.

NOx Emission Limits for Affected Units in Cement and Concrete Products Manufacturing

The NOx emission limits in the final rule for affected kilns in concrete and cement products manufacturing that have the potential to emit (PTE) 100 tons per year (tpy) of NOx are shown in Table 2-1.

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[10] Understanding Cement, Manufacturing - the cement kiln, website at https://www.understanding-cement.com/kiln.html.
[11] Ibid.
[12] Ibid.
[13] Agico Cement, Precalciner, website at https://www.cementplantequipment.com/products/precalciner/.
[14] Agico Cement, Precalciner, website at https://www.cementplantequipment.com/products/precalciner/.

Table 2-1. NOx Emission Limits of Kilns from the Cement and Concrete Industry[15]

Kiln Type	NOx Emissions Limit (lb NOx/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

2.2 Glass and Glass Products Manufacturing

The glass and glass products manufacturing industry manufactures plate glass, glass bottles and containers, automobile windshields, glass tubing, and insulation fiberglass. The NAICS code for glass and glass products manufacturing is 3272xx.[16] Raw materials used in glass production include silica, soda ash, limestone, dolomite, and other chemicals.[17]

Glass products are classified by chemical composition and the type of glass product produced. Glass products include flat glass, container glass, pressed and blown glass, and fiberglass. The manufacturing of such glass occurs in four phases: (1) preparation of raw material, (2) melting in the furnace, (3) forming, and (4) finishing. Phase 1 and 2, the preparation and melting of raw materials, is identical for all glass products. The forming and finishing processes differ depending on the desired glass product. Container glass and pressed/blown glass use pressing or blowing to form the desired product. Flat glass is formed by float, drawing, or rolling processes.

Glass melting furnaces heat the raw materials at high temperatures before glass formation. The furnaces have high energy demands and are the source of most NOx emissions in glass manufacturing. This is due to the high process temperatures where nitrogen and oxygen react.[18] NOx emissions from different furnaces in the glass and glass product manufacturing industry are discussed below.

Container Glass Manufacturing Furnace

Container glass furnaces produce glass products that hold a certain form. Container glass is composed of soda lime, clear or colored, and is pressed or blown into the shape of bottles, ampoules, etc. This type of furnace is used in most glassmaking operations. These furnaces are designed to operate for 24 hours a day and can perform large-scale production.[19]

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[15] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

[16] EPA, Office of Air and Radiation, "Non-EGU Sectors TSD," Draft Technical Support Document for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.

[17] EPA, Glass Manufacturing Effluent Guidelines, website at https://www.epa.gov/eg/glass-manufacturing-effluent-guidelines.

[18] EPA, Office of Air and Radiation, "Non-EGU Sectors TSD," Draft Technical Support Document for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.

[19] Glasstech Refractory, Container Glass Furnaces, website at http://www.glasstechrefractory.com/industrial-solutions/container-glass-furnaces.

Furnaces consist of three main parts, the melter, refiner, and regenerators or checkers. Most furnaces use natural gas, but others can use oil, propane, or electricity. The glass melting furnace reaches temperatures of 1,500 to 1,700°C (2,700 to 3,100°F). Furnaces range in size from 450 to > 1,400 square feet of melter surface. The melter is a rectangular basin that melts raw materials and removes seeds, i.e., fining. Furnaces contain three to seven natural gas burners above glass level to heat the glass at very high temperatures. The burner ports also capture combustion emissions for further processing. After it is melted, the glass passes through a water-cooled tunnel to the refiner. The refiner allows the glass to slowly cool. Regenerators use recycled flue gas which saves energy.[20]

Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace

In creating blown glass, or molded glass, gobs of melted glass from the glass furnace are placed in a molding cavity where air is blown into the glass to expand it to a container shape with a neck. Once it is shaped, the molded glass is now a "parison." This is referred to as the Blow & Blow Process, where compressed air distinguishes the bottle neck finish and gives a uniform shape. During the Press & Blow Process, used to create larger containers, a plunger is inserted into the glass and air is injected to form the bottle shape.[21]

Glass fiber manufacturing is the high-temperature conversion of various raw materials (predominantly borosilicate) into a homogeneous melt, followed by the fabrication of this melt into glass fibers. The two basic types of glass fiber products—textile and wool—are manufactured by similar processes. The primary component of glass fiber is sand, but it also includes varying quantities of feldspar, sodium sulfate, anhydrous borax, boric acid, and many other materials.

Furnace designs vary, but most are large, shallow, and well-insulated vessels fired from above. Raw materials are continuously added into the furnace where they slowly melt and mix into the molten glass. The mixing of the molten glass and raw materials is facilitated by the natural convection of gases rising through the molten glass. Some operators inject air into the bottom of the bed to facilitate convection.

Wool fiberglass insulation has five phases: (1) preparation of molten glass, (2) formation of fibers into a wool fiberglass mat, (3) curing the binder-coated fiberglass mat, (4) cooling the mat, and (5) backing, cutting, and packaging the insulation.

Flat Glass Manufacturing Furnace

The flat glass furnaces behave similarly to container and blown glass furnaces. Flat glass furnaces melt fine-grained ingredients at 1,500°C. Melting, refining, and homogenizing can take up to 50 hours to produce molten glass at 1,100°C, free from inclusions and bubbles. The melting process can be modified by operators depending on the desired product.[22]

During the Float Bath process, molten glass from the furnace flows over a refractory spout onto a level surface of molten tin. The molten glass starts at 1,100°C when leaving the furnace and cools to 600°C

[20] Glass Packing Institute, Glass Furnace Operations, website at https://www.gpi.org/glass-furnace-operation.

[21] Qorpak, Glass Bottle Manufacturing Process, website at https://www.qorpak.com/pages/glassbottlemanufacturingprocess#:~:text=Blown%20Glass%20is%20also%20known,then%20known%20as%20a%20Parison.

[22] Eurotherm, Flat Glass Manufacturing, website at https://www.eurotherm.com/us/glass-manufacture/flat-glass-manufacturing/.

during the float bath process. This gradual temperature cooling treatment relieves stresses in the glass and is called "lehr". Too much stress and the glass will break beneath the cutter.

After the glass has cooled, the glass is inspected by machinery and workers to remove deformed or cracked glass. Inspection technology allows more than 100 million measurements a second across the ribbon, locating flaws the unaided eye would be unable to see.

NOx Emission Limits for Affected Units in Glass and Glass Products Manufacturing

The NOx emission limits on furnaces in glass and glass products manufacturing apply to furnaces that have the potential to emit (PTE) 100 tons per year (tpy) of NOx. The final NOx emission limits for glass manufacturing furnaces are shown in Table 2-2.

Table 2-2. Summary of Final NOx Control Requirements for Glass and Glass Product Industry[23]

NOx Emission Source	NOx Emissions Limit (lb NOx/ton of glass produced)
Container Glass Furnace	4.0
Pressed/Blown Glass Furnace	4.0
Fiberglass Furnace	4.0
Flat Glass Furnace	7.0

2.3 Iron and Steel Mills and Ferroalloy Manufacturing

The iron and steel mills and ferroalloy manufacturing industry is primarily engaged in the production of various steel products, including carbon, alloy, and stainless steels. It is identified by NAICS code 3311 (and related 5- and 6-digit NAICS codes) and encompasses various manufacturing processes. These include:

(1) direct reduction of iron ore;
(2) manufacturing pig iron in molten or solid form;
(3) converting pig iron into steel;
(4) manufacturing ferroalloys;
(5) making steel;
(6) making steel and manufacturing shapes (e.g., bar, plate, rod, sheet, strip, wire); and,
(7) making steel and forming pipe and tube.[24]

Integrated iron and steel production is often misconstrued with electric arc furnace (EAF) steel production. For integrated iron and steel production, a blast furnace (BF) transforms iron ore to molten iron. A basic oxygen furnace (BOF) and molten "pig iron" together create molten steel. This process generates more emissions than EAF steel production. In the BOF, high-purity oxygen oxidizes impurities

[23] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

[24] EPA-HQ-OAR-2021-0668-0504. Comment submitted by Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA).

in the molten bath. Carbon is removed in the form of carbon monoxide (CO) and carbon dioxide (CO_2).[25,26] The molten steel is now the proper grade to be shaped and cooled.[27]

Unlike the BF/BOF process, the EAF process uses electrodes to melt the scrap metal. Oxy-fuel, including natural gas burners, are used to supplement the EAF to obtain the necessary energy requirements. During the refining process for EAF, impurities called "slag" conjoin at the top of the molten metal. Molten slag is removed out a slag door by tipping the furnace, i.e., slagging. The final step is tapping where molten steel is poured in a ladle. Usually, the steel will be further refined in a ladle metallurgy station and/or argon oxygen decarburization. The steel is then cooled and formed into slabs.[28]

Ferroalloys are an alloy of iron with higher impurities of aluminum, magnesium, or silicon. Ferroalloy processing is typically done in a submerged EAF, that, like EAF steel production, use carbon electrodes to heat the scrap metal. A carbon source agent "coke" is typically added. The major alloys produced are silicon alloys (ferrosilicon and calcium silicide), chromium alloys (high carbon ferrochromium in various grades and ferrochrome-silicon), and manganese alloys (standard ferromanganese and silicomanganese).[29,30]

In 2021, 16.39 million metric tons of raw steel was produced in the US, a substantial increase (42%) from 11.57 million metric tons in 2020.[31] One hundred percent of steel can be repurposed without compromising strength or quality, making it the most recycled material.[32] However, the production of iron and steel is energy intensive. In 2021, 6.34 megawatt (MW)-hours of energy per metric ton of raw steel was consumed in the US.[33]

SC&A understands that Reheat furnaces are the only NOx sources at iron and steel mills that are subject to this final rule.

Reheat Furnace

Reheat furnaces at BF/BOR within iron and steel mills heat cold steel to the necessary temperature (~1200°F) before additional processing. The furnace is heated typically with natural gas, which emits

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[25] EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Iron and Steel Industry," September 2012.

[26] EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document -- NOx Emissions from Iron and Steel Mills," September 1994.

[27] EPA-HQ-OAR-2021-0668-0504. Comment submitted by Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA).

[28] EPA-HQ-OAR-2021-0668-0504. Comment submitted by Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA).

[29] EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, "Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources," AP-42, Fifth Edition, Chapter 12.4: Ferroalloy Production, January 1995.

[30] EPA, Ferroalloy Manufacturing Effluent Guidelines, website at https://www.epa.gov/eg/ferroalloy-manufacturing-effluent-guidelines.

[31] United States Steel, Energy Conservation, website at https://www.ussteel.com/sustainability/environmental/energy-conservation.

[32] American Iron and Steel Institute, Sustainability, website at http://www.recycle-steel.org/.

[33] United States Steel, Energy Conservation, website at https://www.ussteel.com/sustainability/environmental/energy-conservation.

NOx. Emissions are typically vented through the building roof monitor. The next stage after the reheat furnace is hot rolling.[34]

NOx Emission Limits for Affected Units in Iron and Steel Mills and Ferroalloy Manufacturing

For the iron and steel mills and ferroalloy manufacturing industry, the only sources included in the final rule are reheat furnaces that have the potential to emit (PTE) 100 tons per year (tpy) of NOx and boilers as affected sources. The affected reheat furnaces would be required to install LNB, with emission limits established based on testing at the unit, as shown in Table 2-3. Boilers are discussed in Section 2.5.

Table 2-3. Summary of Final NOx Control Requirements for the Iron and Steel Industry[35]

NOx Emission Source	NOx Emission Limit or Control Efficiency	Expected Controls	Best Estimate of NOx Reduction
Reheat Furnace	Test and set limit based on installation of Low NOx Burners	LNB	50%

2.4 Pipeline Transportation of Natural Gas

The Pipeline Transportation of Natural Gas industry falls under NAICS code 486210 and comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems. This industry includes the storage of natural gas because the storage is usually done by the pipeline establishment and because a pipeline is inherently a network in which all the nodes are interdependent.

Natural gas compressor stations are located periodically along a transmission pipeline (e.g., every 50 – 100 miles). They function to raise the pressure of the gas to make up for losses due to pipeline friction and changes in pipeline elevation.[36] In 2017, there were reported to be 2,304 compressor stations operating in the U.S. Detailed information was available for 1,197 (or 52% of the total), which indicated that about 80% had more than one compressor unit and around 7 percent had more than 10 compressors. Typically, for compressor stations with multiple units, some of these will be back-up compressors. Available information suggests that capacity utilization at natural gas compressor stations is relatively modest. Assessments of capacity utilization indicate that around 25% of stations are utilized at less than 40% of their capacity. Over 40% of stations are utilized at less than 80% of their capacity. In certifications provided by the U.S. Federal Energy Regulatory Commission (FERC), pipeline operators are required to retain sufficient compression capacity to meet demand on peak demand days (e.g., coldest multi-day event for winter heating). Information from one pipeline operator indicated that their system capacity utilization averaged 30%, and that average utilization in the U.S. was 40%.[37]

[34] AMETEK Land, Reheat Furnace, website at https://www.ametek-land.com/applications/steel/hotrollingreheatfurnace.

[35] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

[36] National Energy Technology Labs (NETL), "Natural Gas Compressors and Processors – Overview and Potential Impact on Power System Reliability," NETL-PUB-21531, July 2017.

[37] EPA-HQ-OAR-2021-0668-0380. Comment submitted by TC Energy.

The NOx sources addressed by the FIP are the prime movers of natural gas compressors: reciprocating internal combustion engines (RICE). All the identified sources are fired by pipeline gas.[38] RICE used at compressor stations affected by the FIP are those >1,000 horsepower (hp). RICE are further differentiated by three engine types:

- 2-stroke lean-burn
- 4-stroke lean-burn
- 4-stroke rich-burn

The final rule includes EPA's NOx emission limits on RICE in pipeline transportation of natural gas with nameplate rating of ≥1,000 brake-horsepower (bhp). Table 2-4 provides the NOx emission limits for these RICE.

Table 2-4. Proposed NOx Emission Limits for Natural Gas-Fired RICE in Pipeline Transportation of Natural Gas[39]

Engine Type	Emissions Limit (g/hp-hr)
4-Stroke Rich Burn	1.0
4-Stroke Lean Burn	1.5
2-Stroke Lean Burn	3.0

2.5 Boilers in the Iron and Steel Mills and Ferroalloy Manufacturing, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, and Metal Ore Mining Industries

The non-EGU affected industries with boilers subject to the final rule are: Iron and Steel Mills and Ferroalloy Manufacturing; Basic Chemical Manufacturing; Petroleum and Coal Products Manufacturing; Pulp, Paper, and Paperboard Mills; and Metal Ore Mining. The final rule includes NOx emission limits on boilers using fossil fuels n all affected industries. These fuels include coal, residual oil, distillate oil, and natural gas. Natural gas units are the most common of the non-EGU boilers affected by the final rule. The emission limits (30 day rolling average) for these boilers by fuel type can be seen in Table 2-5. These limits apply to boilers used in the affected industries that have a design capacity of ≥100 MMBtu/hr.

[38] National Energy Technology Labs (NETL), "Natural Gas Compressors and Processors – Overview and Potential Impact on Power System Reliability," NETL-PUB-21531, July 2017. 77% of stations were fueled by natural gas, 17% could operate on either electricity or natural gas, and 6% were powered solely by electricity.
[39] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

Table 2-5. NOx Emission Limits for Non-EGU Affected Industry Boilers[40]

Unit Type	Emissions Limit (lb NOx/MMBtu)
Coal	0.20
Residual Oil	0.20
Distillate Oil	0.12
Natural Gas	0.08

Basic chemical manufacturing includes both organic and inorganic chemicals manufacturing (i.e., NAICS code 3251). Petroleum and coal products manufacturing includes NAICS code 3241). Pulp, paper, and paperboard mills include newsprint mills (i.e., NAICS code 3221). Metal ore mining includes NAICS codes 2122. Additional descriptions for these affected industries are provided below.
Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines. The three main types of boilers are described below:[41]

- Firetube boilers. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 million British thermal units (MMBtu)/hr.
- Watertube boilers. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a "wall." Watertube boilers vary in size from less than 10 MMBtu/hr to 10,000 MMBtu/hr.
- Fuel-firing. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to "suspend" the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

A brief description of each of the affected industries with boilers is provided in the following sections.

<u>Basic Chemical Manufacturing</u>
The Basic Chemical Manufacturing industry transforms inorganic and organic materials into a desired chemical product. The products include basic chemicals, coatings and adhesives, resins, cleaning products, pesticides, and pharmaceuticals. The Basic Chemical Manufacturing industry is identified by NAICS code 3251.

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[40] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.
[41] Northeast States for Coordinated Air Use Management (NESCAUM), "Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers," January 2009. Available at https://www.nescaum.org/documents/ici-boilers-20081118-final.pdf.

Boilers in the Basic Chemical Manufacturing industry play a crucial role. Boilers are used in producing steam, boiling, and energy production. Steam is commonly used because it evenly distributes heat, carries ample heat, and is an efficient energy transfer process. Steam allows for easy adjustments of temperature and pressure, as well as slowly cooling or heating a chemical reactor.

Some processes in the Basic Chemical Manufacturing industry that use boilers are as follows:

- Boilers power exhaust fans to vent fumes during production.
- Boilers heat and cool reactors with steam or water.
- Waste heat boilers reuse heat energy to reduce waste.
- Boilers produce the electricity needed to run the plant.

Petroleum and Coal Products Manufacturing

The Petroleum and Coal Products Manufacturing industry transforms crude petroleum and coal into desired products. Some of these products include gasoline, diesel fuel, asphalt, lubricating oils, paraffin waxes, and transmission fluids. This industry is dominated by petroleum refineries. The Petroleum and Coal Products Manufacturing industry is identified by NAICS code 3241.

Crude oil is superheated in a furnace and turns from a liquid to a gas. The superheated gas is transferred to the bottom of the distillation tower. The oil begins to cool and return to a liquid in the tower. Using stacking trays, heavier oils will remain at the bottom of the distillation tower while lighter oils will raise to the top of the tower. This process discriminates crude oil by boiling point, density, and grade. Light oils have less than 10 elements of carbon and low boiling points under 120°C. These oils become propane and natural gas, for example. Lighter oils are more valuable and require less processing. Heavy oils have greater than 30 elements of carbon and higher boiling points over 300°C. These oils become residual oil, asphalt, or tar. Oil refineries have cracking units that transform unusable heavy oils into lighter oils. This is accomplished by catalysts breaking long chain carbon bonds into shorter hydrocarbons. These lighter fuels are now more valuable to the industry.

Boilers play a crucial role in the Petroleum and Coal Products Manufacturing industry. Their main purpose is to heat oil for distillation. Boilers heat the crude oil in the furnace, distillation tower, and cracking unit to promote the separation of oil grades. Refineries typically use water tube and fire tube boilers.

Pulp, Paper, and Paperboard Mills

Paper production begins with harvesting trees. Next, the bark is removed, and the wood chips are placed in a digester to remove their lignin content. This process is very energy intensive, using half the total energy demand of an entire pulp and paper plant in this one step.[42] What remains is "pulp," which is then filtered and bleached, and then additives are added into the pulp. To process pulp into paper, the pulp is squeezed through rollers to form sheets. This also removes most additional water content in the paper. The paper is then rolled into reels for any further processing, such as cutting, color, or strength additives. The Pulp, Paper, and Paperboard Mill industry is identified by NAICS code 3221.

Boilers play a crucial role in the pulp and paper industry. Boilers are primarily used in this industry in producing steam, boiling, and energy production. Steam is commonly used because it evenly distributes

[42] Energy Link, Top 4 Energy Consumers in the Paper Manufacturing Industry, website at https://goenergylink.com/blog/paper-manufacturing-industry-the-top-4-energy-consumers/.

heat, promotes uniformity and increased strength in the final paper product. Steam is also used because it carries ample heat and is an efficient energy transfer process. Steam allows for easy adjustments of temperature and pressure, depending on the grade of paper needed.

Some processes in the pulp and paper industry that use boilers are as follows:

- In the digester, tree scapings are boiled to remove lignin and make pulp.
- Steam uniformly heats the paper rolls during the rolling process.
- Steam dries the paper before rolling.
- Boilers are used in the reuse and purification of water.
- Boilers produce the electricity needed to run the plant.

Metal Ore Mining Industry

The metal ore mining industry extracts desired metals to produce a product. The most mined metals include iron and copper. Other examples include nickel, rare earth metals, cobalt, manganite, and uranium ores. Metals are mined for renewable energy, electronic wiring, steel production, and batteries. The Metal Ore Mining Industry is identified by NAICS code 2122.

Metal ore mines can be above or below ground. Metals originate in rock with some ores containing less than a percent of the desired metal. As a result, massive amounts of rock must be extracted to meet demand. The Metal Ore Mining Industry requires heavy machinery and explosives to crush and drill through rock. A meta-analysis on energy consumption was performed on the gold, copper, nickel, lithium, and iron mining industries. Copper is the most energy intensive and 46% of the energy consumed is diesel, mainly for off-grid mobile equipment.[43]

After the rock is extracted, it undergoes crushing and grinding, a concentrator to remove impurities, and metals recovery.[44] Although most of the energy consumption in the mining industry is off grid, boilers are used as a power source and/or output steam to produce heat energy. Boilers have been used in ore mining and beneficiation, or the removal process of gangue minerals. Metals recovery requires heat and steam and is a process in the metal ore mining industry that can utilize boilers.[45]

2.6 Municipal Waste Combustors

Municipal waste combustion involves the burning of garbage and other nonhazardous solids, collectively referred to as municipal solid waste (MSW), to generate electric power.[46] The NAICS code for Solid Waste Incinerators and Combustors is 562213. MSW is a mixture of energy-rich materials such as paper, plastics, yard waste, and products made from wood. For every 100 pounds of MSW in the United States, about 85 pounds can be burned as fuel to generate electricity. Waste-to-energy plants can reduce 2,000

[43] Allen, M. Mining Energy Consumption 2021, Engeco.
[44] EPA, Explore a Metal Mine that Reports to the TRI Program, website at: https://www.epa.gov/toxics-release-inventory-tri-program/explore-metal-mine-reports-tri-program.
[45] DHB Boiler, Mining, website at: https://dhbboiler.com/mining/.
[46] EPA, AP-42 Compilation of Air Pollutant Emissions Factors, Section 2.1 Refuse Combustion, October 1996, available at https://www3.epa.gov/ttnchie1/ap42/ch02/final/c02s01.pdf.

pounds of garbage to ash weighing about 300 pounds to 600 pounds, and they reduce the volume of waste by about 87%.[47]

Municipal waste combustors (MWC) are intended to reduce the volume of MSW through combustion of that solid waste. MSW is a fuel that tends to be a heterogeneous mixture of heavy and light materials of various combustibility. Most MWCs are designed to recover some of the heat generated from the MSW combustion process through heat absorption by radiant and convective water-cooled and steam-cooled tubing surfaces. MWCs may incorporate the steam generator within the MWC as an integral component, or the steam generator is a separate entity acting as a waste heat recovery device attached to the MWC. There are many designs and configurations of MWC units, often depending upon the intended volume of MSW throughput, characteristics of the design "municipal waste fuel", and the experience and preferences of the owner/operator and engineering/design organization.[48]

Nitrogen oxides in the MWCs are formed primarily during combustion through the oxidation of nitrogen-containing compounds in the waste at relatively low temperatures (<1,090°C or 2,000°F), and negligibly through the fixation of atmospheric nitrogen, which occurs at much higher temperatures. Because of the kind of fuel MWCs use and the relatively low temperatures at which they operate, 70–80% of NOx formed in MSW incineration is associated with nitrogen in the MSW.[49]

There are different types of waste-to-energy systems or technologies. The most common type used in the United States is the mass-burn system, where unprocessed MSW is burned in a large incinerator with a boiler and a generator for producing electricity. Another less common type of system processes MSW to remove most of incombustible materials to produce refuse-derived fuel (RDF).[50] There is also a smaller and more portable type of system known as modular systems.

Mass Burn Facilities

At an MSW combustion facility, MSW is unloaded from collection trucks and placed in a trash storage bunker. An overhead crane sorts the waste and then lifts it into a combustion chamber to be burned. The heat released from burning converts water to steam, which is then sent to a turbine generator to produce electricity.

The remaining ash is collected and taken to a landfill where a high-efficiency baghouse filtering system captures particulates. As the gas stream travels through these filters, more than 99 percent of PM is removed. Captured fly ash particles fall into hoppers (funnel-shaped receptacles) and are transported by an enclosed conveyor system to the ash discharger. They are then wetted to prevent dust and mixed with the bottom ash from the grate. The facility transports the ash residue to an enclosed building where it is loaded into covered, leak-proof trucks and taken to a landfill designed to protect against

[47] U.S. Energy Information Administration (EIA), Biomass explained Waste-to-energy (Municipal Solid Waste), website at https://www.eia.gov/energyexplained/biomass/waste-to-energy-in-depth.php#:~:text=Waste%2Dto%2Denergy%20plants%20burn,and%20products%20made%20from%20wood.

[48] Ozone Transport Commission Stationary, Area Sources Committee, "Municipal Waste Combustor Workgroup Report," April 2022.

[49] EPA, AP-42 Compilation of Air Pollutant Emissions Factors, Section 2.1 Refuse Combustion, October 1996, available at https://www3.epa.gov/ttnchie1/ap42/ch02/final/c02s01.pdf.

[50] U.S. Energy Information Administration (EIA), Biomass explained Waste-to-energy (Municipal Solid Waste), website at https://www.eia.gov/energyexplained/biomass/waste-to-energy-in-depth.php#:~:text=Waste%2Dto%2Denergy%20plants%20burn,and%20products%20made%20from%20wood.

groundwater contamination. Ash residue from the furnace can be processed for removal of recyclable scrap metals.[51]

There are 2 major sub-categories of mass burn MWCs—mass burn waterwall MWCs and rotary waterwall MWCs, discussed below.[52]

Mass Burn Waterwall MWCs

Mass burn waterwall MWCs have lower furnace primary combustion zones made of waterwall tubes for heat transfer in the combustion zone. For mass burn waterwall MWCs, the MSW fuel is typically loaded into charging hoppers and fed to hydraulic rams that push the MSW fuel onto the stoker grate in the furnace for combustion. Most stokers utilize a reciprocating grate action, utilizing either forward or reverse acting grate movement, which moves the combusting MSW fuel across the furnace to allow time for drying and complete combustion. Generally, there will be a large volume of fuel at the front end of the grate that burns down to a small amount of ash at the back of the grate. The grate may have a slightly downward angle from fuel introduction to the ash drop off to help move the MSW fuel through the furnace. The reciprocating action of the grates also tends to agitate the MSW fuel, generally causing the MSW fuel to roll and mix. This agitation helps ensure all the MSW fuel is exposed to the high temperatures in the bed of combusting MSW fuel and helps provide contact with combustion air, resulting in more complete combustion of the MSW fuel as it travels across the furnace. Combustion ash that does not leave the stoker grate as fly ash is dropped off at the end of the stoker through a discharge chute for disposal or further processing.

Mass burn waterwall MWCs may also incorporate auxiliary fuel burners to help bring the MWCs to temperature to begin combustion of the MSW fuel, to supplement the heat input necessary to attain the steam generator output rating with varying MSW fuel quality, or to ensure sufficient flue gas temperatures are attained for proper emissions control.

Combustion air is generally introduced to the combustion zone utilizing pressurized air as underfire (primary) air or overfire (secondary) air. At least one proprietary design, however, splits the overfire air into two distinct zones, effectively creating three combustion air introduction zones.

Underfire air is introduced under the stoker grate, sometimes through a series of plenums that allow for underfire air introduced to various portions of the grate area to be controlled to enhance combustion based on MSW fuel characteristics. The underfire air travels from the plenums to the combustion zone through holes in the grate to assure good distribution across the grate. Underfire air systems are generally designed to be able to provide up to 70% of the total combustion air requirement, with typical underfire air operating requirements utilizing 50% to 60% of the total combustion air.

Overfire air is introduced into the furnace above the grate level through multiple ports in the furnace walls. The primary purpose of the overfire air is to provide the amount of air necessary to mix the furnace gasses leaving the grate combustion zone and provide the oxygen required to complete the combustion process. Proper control of the overfire air may also be utilized to provide some control of

[51] EPA, Energy Recovery from the Combustion of Municipal Solid Waste (MSW), website at https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw.
[52] Ozone Transport Commission Stationary, Area Sources Committee, "Municipal Waste Combustor Workgroup Report," April 2022.

the NOx emission rate leaving the high temperature zone of the furnace. The amount of overfire air is typically 40% to 50% of the total required combustion air and is somewhat dependent upon MSW fuel quality and NOx emission control requirements.

Rotary Waterwall MWCs

A rotary waterwall MWC utilizes a water-cooled, tilted, rotating cylindrical combustion chamber. The MSW fuel is typically loaded into charging hoppers and fed to hydraulic rams that push the MSW fuel into the slowly rotating combustion chamber. The rotation of the tilted cylindrical combustion chamber causes the MSW fuel to tumble and advance the length of the cylindrical combustion chamber, ensuring all the MSW fuel is exposed to high temperatures and combustion air for a sufficient amount of time for drying and complete combustion of the MSW fuel. Combustion ash that does not leave the rotary burner as fly ash is dropped off at the end of the rotary burner through a discharge chute for disposal or further processing.

Rotary burner MWCs may also incorporate auxiliary fuel burners to help bring the MWCs to temperature to begin combustion of the MSW fuel, to supplement the heat input necessary to attain the steam generator output rating with varying MSW fuel quality, or to ensure sufficient flue gas temperatures are attained for proper emissions control.

Combustion air for rotary burner MWCs is introduced to the rotating combustion chamber by a pressurized plenum surrounding the rotating combustion chamber. The combustion air enters the rotating combustion chamber through the walls of the chamber, generally through spaces between waterwall tubes. Underfire air is introduced at the bottom of the rotating combustion chamber and through the bed of combusting MSW. Overfire air is introduced into the rotating combustion chamber over the bed of combusting MSW. Dampers are utilized to proportion the total air flow and control the overfire air/underfire air split. Because the waterwall tubes form the floor of the combustion zone and effectively remove heat from that surface, peak combustion temperatures may tend to be lower than experienced with other MWC designs, helping reduce the NOx emissions relative to those other MWC designs. Also, as the water-cooled surfaces require lower amounts of initial combustion zone excess air for cooling of combustor components, lower amounts of total excess air may be required for many rotary burner MWCs compared to some other MWC designs. The reduced excess air requirements may also help to reduce base NOx emissions relative to other MWC designs.

Refuse-Derived Fuel Systems

Refuse-Derived Fuel (RDF) systems use mechanical methods to shred incoming MSW, separate out non-combustible materials, and produce a combustible mixture that is suitable as a fuel in a dedicated furnace or as a supplemental fuel in a conventional boiler system.[53]

In an RDF system, the following processes are performed:[54]

- Crushing process: Refuse is crushed to the appropriate size for drying.
- Drying process: High-temperature blast dries and deodorizes refuse.

[53] EPA, Energy Recovery from the Combustion of Municipal Solid Waste (MSW), website at https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw.
[54] Kawasaki Heavy Industries, Refuse-derived Fuel (RDF) Manufacturing Plant, website at https://global.kawasaki.com/en/industrial_equipment/environment_recycling/waste/rdf.html.

- Sorting and Crushing process: Unsuitable substances for fuel such as iron and stone are removed. Refuse is crushed to the appropriate size for forming RDF.
- Solidifying process: Additive is supplied to prevent corruption. Substances are formed to produce high-density and high-strength RDF that is suitable for transportation, storage, and combustion.

Modular System

Modular Systems burn unprocessed, mixed MSW. They differ from mass burn facilities in that they are much smaller and are portable. They can be moved from site to site.[55] One of the most common types of modular system is the starved air or controlled air type combustor which incorporates two combustion chambers. Air is supplied to the primary chamber at sub-stoichiometric levels and the resultant incomplete combustion products (CO and organic compounds) pass into the secondary combustion chamber where combustion is completed with the additional air. Another modular system design is the excess air combustor which, like the starved air combustor, also consists of two chambers but is functionally similar to mass burn units in its use of excess air in the primary chamber.[56]

NOx Emission Limits for Affected Units in Municipal Waste Combustion

Table 2-6 summarizes the NOx emission limits for large MWCs, which are defined as incinerators that combust greater than 250 tons per day of municipal solid waste. Note that both the 24-hour average limit and the 30-day average limit must be met.

Table 2-6. NOx Emission Limits for Large MWCs[57]

Unit Type	Emissions Limit (parts per million by volume, dry basis NOx [ppmvd])
Combustors or Incinerators	110 ppmvd on a 24-hour averaging period and 105 ppmvd on a 30-day averaging period

[55] EPA, Energy Recovery from the Combustion of Municipal Solid Waste (MSW), website at https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw.
[56] EPA, AP-42 Compilation of Air Pollutant Emissions Factors, Section 2.1 Refuse Combustion, October 1996, available at https://www3.epa.gov/ttnchie1/ap42/ch02/final/c02s01.pdf.
[57] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

3. Non-EGU NOx Emission Controls

This section provides brief descriptions of the NOx control technologies that SC&A estimates affected non-EGU sources may apply to meet the emission limits of the final rule. It is not meant to cover all possible NOx control technologies that could achieve the NOx emission limits for the sources affected by the final rule.

3.1 External Combustion Controls

Low NOx Burners

Low NOx burners (LNB) are designed to control combustion fuel and air mixing in such a way as to create larger and more branched flames, which reduce peak flame temperatures. By lowering peak flame temperatures, thermal NOx formation is reduced. The initial stage of combustion occurs in a fuel rich, oxygen deficient zone where NOx is formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed NOx. In the third stage of combustion, internal air staging (additional air) completes the combustion but may result in additional NOx formation. This however can be minimized by completing the combustion in an air lean environment.[58]

LNBs can be applied to a variety of industrial NOx emission sources including furnaces, some kilns, and boilers, but can vary in the level of NOx control achieved across such sources. In the iron and steel industry, reheat furnaces show a relatively high NOx reduction potential of 66% with the application of LNB. In contrast, LNB technology only reduces NOx emissions from indirect-fired cement kilns by 25%. LNB can reduce NOx emissions by 50% NOx from industrial boilers, regardless of fuel type.[59]

Flue Gas Recirculation

In FGR, cooled flue gas and ambient air are mixed to become the combustion air and are reintroduced to the system by fans and flues. The mixing reduces the oxygen content of the combustion air supply and lowers the combustion temperature. FGR is feasible if there is no minimum operation temperature and/or oxygen requirement for the boiler as FGR lowers the temperature range and oxygen levels in the boiler. FGR may affect fan capacity, furnace pressure, burner pressure drop, and turndown stability, so it may not be feasible for boilers where these are critical parameters. FGR is commonly implemented in conjunction with LNB.[60]

Covanta Patented Low NOx Technology

Covanta's patented Low NOx Technology (LN^tm^) is a proprietary combustion technology developed by Covanta to reduce NOx emissions from MSW combustion. LN^tm^ encompasses a process that modifies combustion in a furnace by diverting a portion of the secondary emissions and then injecting it at a higher elevation in the furnace. This system optimizes combustion and reduces NOx emissions by distributing combustion air between the primary, secondary, and tertiary levels and providing additional fuel/air staging for NOx control while still providing enough air for complete combustion. This system has been installed on many MWC units operated by Covanta. It has been shown that this system can achieve an annual NOx emission limit of 90 ppm and a daily NOx emission limit of 110 ppm. However,

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[58] Goes Heating Systems, Low NOx Burners, website at https://goesheatingsystems.com/low-nox-burners/.
[59] EPA, Office of Air and Radiation, "Non-EGU Sectors TSD," Draft Technical Support Document for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[60] EPA, Menu of Control Measures for NAAQS Implementation, menuofcontrolmeasures.pdf, website at https://www.epa.gov/sites/default/files/2016-02/documents/menuofcontrolmeasures.pdf.

the proprietary aspects of the technology may make it unlikely that it could be applied to non-Covanta MWCs. Additionally, not all Covanta MWC configurations may be able to incorporate the components needed for LN^{tm}. This technology is typically used in conjunction with selective non-catalytic reduction (SNCR)[61] and, for the sources for which LN^{tm} is the control technology applied in the final rule cost analysis, it is always paired with SNCR.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is the most widely used post-combustion NOx reduction technology. SCR uses a reducing agent to convert NOx to desirable gases. The reductant is typically ammonia or urea. In ammonia reduction, NOx in the flue gas is injected with aqueous ammonia onto a catalyst that speeds up the reaction. After completion, NOx has been converted to nitrogen gas and water. Urea reduction operates similarly, but the products are carbon dioxide, nitrogen gas, and water.

SCR requires regular maintenance to perform properly, as it is a temperature-dependent system, ideally operating between 550-800°F.[62] When temperatures are out of this range, "ammonia slip" occurs. Ammonia slip is a major issue in SCR operation in that ammonia will pass through the SCR unreacted. Ammonia gas must be properly distributed in the chamber for the needed chemical reactions to occur. Due to the harsh nature of flue gases and ammonia, SCR equipment has a finite life. This is especially true for the catalyst. The catalyst pores can get clogged and contaminated by soot particles depending on the effectiveness of large particle ash filters, often used with SCR that are applied to coal-fired units If catalyst pores become clogged and contaminated by soot particles, the operator may need to replace the catalyst.

SCR is a dominant NOx control technology due to its high NOx removal efficiency. SCR can typically achieve greater than 80% NOx reduction. SCR has been successfully used on boilers, annealing furnaces, four stroke lean burn spark ignition engines, and other equipment. SCR may not be feasible if the flue gas temperature is not within an acceptable range, in exhaust environments that could poison the catalyst (e.g., acid gases; alkali metals, such as sodium or potassium), or in operations with limited space that may be insufficient for SCR installation. For the external combustion sources, SCR is EPA's applied control technology for some of the affected boilers in the final rule cost analysis.

Selective Non-Catalytic Reduction

SNCR is another post-combustion technology. The major difference between SCR and SNCR is that SNCR does not use a catalyst. The SNCR procedure is like SCR in that ammonia or urea is injected into the flue gas to convert NOx to clean gas. The absence of a catalyst allows for higher flue gas temperatures between 1,400 to 1,600°F. SNCR has the potential to reduce NOx emissions by 35 to 75%.[63] SNCR has many of the same disadvantages as SCR. SNCR is prone to ammonia slip, installation spacing is a concern, and the flue gas temperature must be in the proper range. In the final rule cost analysis, SNCR is the control EPA's technology applied at affected cement kilns and in combination with LN^{tm} at some affected MSW combustors and incinerators.

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[61] Ozone Transport Commission Stationary, Area Sources Committee, "Municipal Waste Combustor Workgroup Report," April 2022.
[62] EPA, Office of Air and Radiation, "Non-EGU Sectors TSD," Draft Technical Support Document for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[63] Ibid.

Advanced SNCR
Advanced selective non-catalytic reduction (ASNCR) can be used to upgrade existing SNCR installations or can be used as a new retrofit technology for MWCs. As with SNCR, ASNCR involves the injection of reagents into the proper temperature zones of a furnace to reduce the NOx concentration in the flue gas. The main difference between ASNCR and SNCR is that ASNCR uses advanced furnace temperature monitoring that provides near real-time feedback on the temperature profile of the furnace. The ASNCR system then automatically adjusts the individual injector flow rates to optimize the NOx emission reductions. This helps to reduce the magnitude of NOx spikes that occur in MWC furnaces due to combusting a mixture of fuels while also keeping a low level of ammonia slip. ANSCR can reduce NOx emissions by about 70% and should be applicable to many MWCs as a retrofit control technology, although the furnace configuration and other factors could limit the NOx reduction potential.[64] In the final rule cost analysis, ASNCR is the control technology that is applied to a majority of the affected MSW combustors and incinerators.

3.2 Internal Combustion Controls for Engines

Layered Combustion
Layered combustion (LC) which is used for 2-stroke lean burn engines consists of multiple technologies:

- High-pressure fuel injection
- Turbocharging
- Precombustion chamber
- Cylinder head modifications

The estimated range of NOx reductions from the use of LC technologies is 60 – 90%.[65] For 2-stroke engines, the final rule contains an emissions limit of 3.0 g NOx/hp-hr, which should be achievable using LC controls. In the final rule cost analysis, LC is the applied control technology for 2-stroke lean burn engines.

Non-Selective Catalytic Reduction
For rich burn RICE (excess oxygen less than 0.5% in the exhaust), non-selective catalytic reduction (NSCR) is the commonly accepted emissions control, not only for NOx, but for CO and volatile organic compounds (VOC) as well. NSCR is often referred to as a 3-way catalyst control, since it addresses all 3 pollutants (CO and VOC are oxidized, while NOx is reduced to nitrogen). It is also used in gasoline vehicles ("catalytic converters"). Automatic air to fuel control systems are needed to maintain exhaust oxygen levels below 0.5 percent. NOx control efficiencies are reported to range from 90 – 98 percent.[66] NSCR is the applied control technology for 4-stroke rich burn engines in the final rule cost analysis.

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[64] Ozone Transport Commission Stationary, Area Sources Committee, "Municipal Waste Combustor Workgroup Report," April 2022.
[65] EPA, Office of Air and Radiation, "Non-EGU Sectors TSD," Draft Technical Support Document for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[66] EPA, Office of Air Quality Planning and Standards, EPA-453/R-93-032 Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines, July 1993, available at https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf.

Selective Catalytic Reduction

For lean burn RICE and gas turbines, SCR might be considered in cases where LC controls are not able to meet the desired NOx emission limits. As of 2014, SCR application on sources in the pipeline transportation of natural gas industry was very limited, especially as a retrofit; however, some new four-stroke lean-burn engines had been sited with SCR.[67] Just as with external combustion sources described above, SCR involves the injection of a reagent (ammonia or urea) to "selectively" reduce NOx across a catalyst bed. The application of SCR is more challenging for RICE due to the need for the exhaust gas to be within an effective operating range (480 – 800 Fahrenheit) and fluctuations in NO/NO_2 ratios in the exhaust (which affect the required reagent feed rate). Applications on engines with variable power loads is particularly challenging, and the use of a continuous emissions monitor (CEM) may be required for precise reagent control. SCR is the applied control technology for 4-stroke lean burn engines in the final rule cost analysis.

[67] Interstate Natural Gas Association of America (INGAA), "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Prime Movers Used in the Interstate Natural Gas Transmission Industry," prepared by Innovative Environmental Solutions and Optimized Technical Solutions, INGAA Foundation Final Report No. 2014.03, July 2014.

4. Timing to Install Controls

4.1 Phases Common to Control Installations

This section discusses steps or work elements required to install NOx control technologies for non-EGUs to attain compliance with this rule.

In general, installation of NOx control equipment for regulatory compliance occurs in two major distinct phases: the analysis phase culminating in a decision, typically designated as pre-award/preconstruction activities, and the implementation phase of an engineering, procurement, and construction (EPC) contract award. Considering that design, construction materials, labor to install controls, and commissioning can account for a large portion of the project's total capital cost, corporate management often expends significant effort upfront analyzing options for regulatory compliance to minimize financial risk before awarding a contract for materials and services.

The path to contract award contains several work elements. Figures 4-1 and 4-2 illustrate general timelines for control installation, showing these work elements. Timelines for some of the common steps for NOx control installation were adapted from an EPA technical memorandum.[68] A final step for obtaining operating permits was also added for situations where those are required (some states have a combined process for permits to construct and operate, while in others, these are two separate processes). The timeline for large add-on controls such as SNCR or SCR to large industrial sources (including large MWCs) is shown in Figure 4-1 while the general timeline addressing combustion controls and small add-on controls, such as compact SCR or NSCR applied to RICE, is shown in Figure 4-2. The longer general timeline indicated for large add-on controls reflects the likely challenges in engineering and fabrication (including site-specific design and construction challenges).

[68] B. Lange, Eastern Research Group, "NOx APCD Installation Times Early Findings," prepared for D. Misenheimer, US EPA, March 2017.

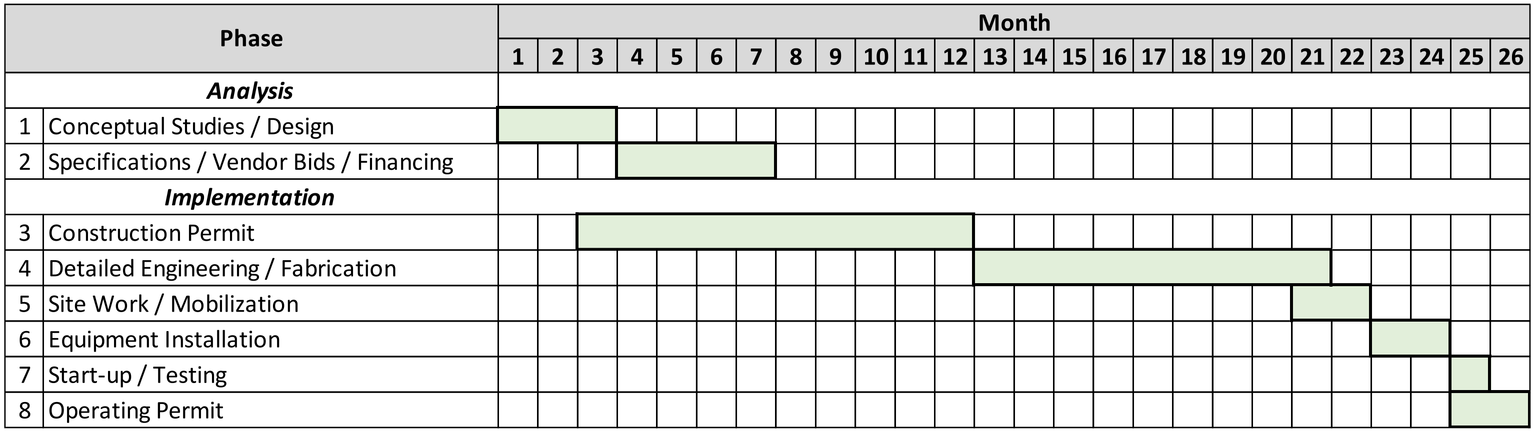

Figure 4-1. General Installation Timeline: Large Add-On Controls

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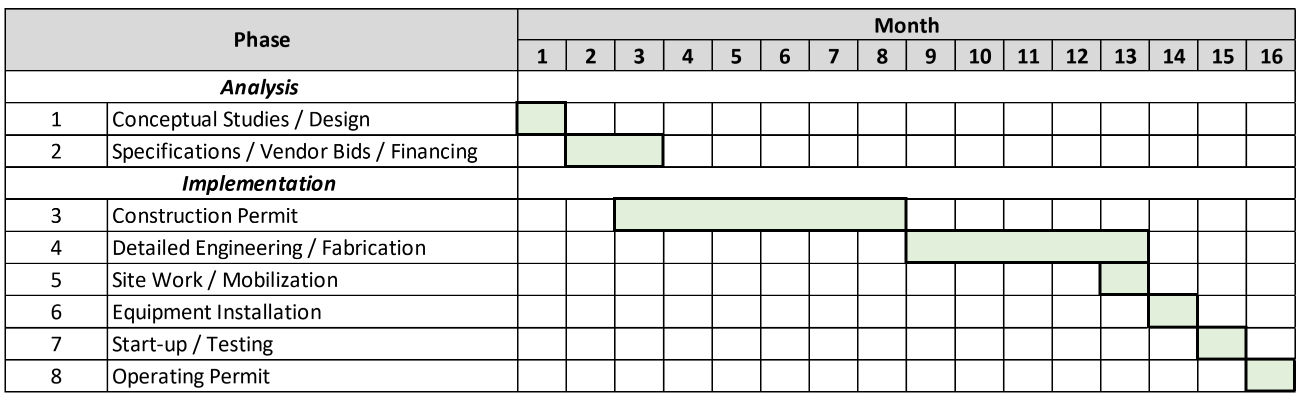


Figure 4-2. General Installation Timeline: Combustion Controls or Compact Add-On Controls

As indicated in the figures above, some overlap can occur among the phases of installation. For example, review of construction permit applications often occurs before the end of the analysis phase, since affected sources would not go out to bid on a project or sign contracts with vendors before receiving construction permits. In addition, site work can also begin before the control equipment is fabricated and delivered. The greater the amount of such overlap in phases of installation, the less time control installation may take. Additional descriptions of the activities occurring within each phase of control installation follow:

1. Conceptual Studies/Design Basis – In the first phase of technology evaluation, an engineering review and assessment of the combustion unit is conducted to determine the preferred compliance alternative. During this phase, the specifications of the control technology are determined, and bids are requested from vendors. A request for proposal (RFP) is often a route by which to accomplish this. An RFP is submitted for emission control vendors to present competing technologies, their capabilities, and their approximate costs (often +-30%, or study-level in accuracy).[69] The RFP process is a broad market sweep that invites control vendors to propose a remedy for regulatory compliance, which then allows the owner to focus on a technology, consider budgetary constraints, and narrow the list of competing vendors. The RFP process can often take 3-4 weeks depending on the extent of the project.
   The final part of the pre-award phase involves selecting a control vendor, otherwise known as the Request for Quotation (RFQ) process. For the vendor, creating a bid package can incur substantial development costs since this requires assembling sufficient staff to develop an accurate price based on current market conditions for key inputs (materials, labor, etc.) while adhering to the client's specifications in the RFQ. Typically, the vendor commits a month to create a bid package, but the process can end in 6-8 weeks. An owner's review of vendor bids may take 3-4 months before targeting a single vendor. However, much of this effort can be conducted simultaneously with the permit application process (discussed below), leaving the final contract signature to be done. Depending on the complexity of the control retrofit, commenters on similar EPA rulemakings stated that it can take 6-8 months after the rule is finalized to select a control option and hire an installation contractor.
2. Specifications/Vendor Bids/Financing– Once both parties (i.e., a buyer organization and seller organization) agree on the technical and commercial terms and conditions of the proposal, they move on to next steps like contract signing and statement of work, which formalize the purchase transactions. Financing for equipment purchases is also conducted during this phase.
3. Preparation and Review of Construction Permits – Before construction to install the technology can commence, the facility must prepare, submit, and receive approval for a construction permit from the relevant federal, state or local regulatory authority. The construction permit covers modifying existing equipment or installing new equipment. A construction permit application can include the following elements: a) project description, b) emission controls, c) project operation, d) site layout, e) waste disposal, and f) construction activities. The permitting agency reviews the application and issues a draft approval. Construction permit processing times typically range from 3 months to a year.

[69] B. Lange, Eastern Research Group, "NOx APCD Installation Times Early Findings," prepared for D. Misenheimer, US EPA, March 2017.

4. Detail Engineering/Fabrication – Even after a company hires a vendor, the company needs additional time to order and install equipment. The length of time depends on the types of equipment or controls chosen and obtaining certain pieces of equipment sometimes involves significant lead times. When engineering details are finalized, equipment is fabricated under this phase.
5. Site Work/Mobilization – During the pre-construction stage, a site investigation must be completed. A site investigation identifies any steps that need to be implemented on the job site before the actual construction begins. Most of the construction activities, such as earthwork, foundations, process electrical and control tie-ins to existing items, can occur while the emitting unit is in operation.
6. Equipment Installation – This phase addresses all on-site installation activities. For most types of NOx control, the affected units may need to be shut down to allow for installation.
7. Startup and Testing – Newly installed equipment requires a shakedown or a trial period to identify and address any issues before the control device is declared operational.
8. Revision and Review of Operating Permits - Facilities must also modify their Title V operating permit to incorporate the added control devices and the associated reduced emission limits. The review and revision of operating permits can include the following elements: a) current and projected emissions, b) identification of regulatory status for multiple Clean Air Act programs, such as Prevention of Significant Deterioration (PSD)/ New Source Review (NSR), Regional Haze, and various Federal water programs (e.g., National Pollutant Discharge Elimination System), and c) state and local requirements.

Table 4-1 presents estimates of the amount of time required for individual sources affected by the final rule to install the controls that EPA estimates might likely be installed for compliance.[70] The amount of time required for equipment design/fabrication/installation was taken from information in comments to the proposed rule and supporting technical documents. These estimates do not include the additional time required for the analysis phase and permitting. Thus, estimates of the time needed for the analysis phase and permitting are presented in a separate column. Assumptions for these phases are as follows:[71]

- Conceptual Studies/Design: range of months for SNCR/SCR: 1 - 5 months; low end of range assumed for combustion controls and compact add-ons.
- Specs/Vendor Bids/Financing: range of months for SNCR/SCR: 2 - 6 months; low end of range assumed for combustion controls and compact add-ons.
- Permitting: range of months for any control type: 2 – 12 months; includes both construction and operating permit phases. The final two months are assumed for the operating permit, where those are separate from construction permits. For layered combustion or NSCR applied to RICE in natural gas transportation or LNB applied to boilers and furnaces, 2 – 3 months is expected. For all other controls, a range of 6 - 12 months is expected.

[70] For facilities that have multiple affected units to address, the amount of time required to install each control could be reduced on average, since a single permit review process would likely be involved among other efficiencies in equipment design, fabrication, and installation.
[71] Lange, B., Eastern Research Group, Technical Memorandum (NOx APCD Installation Times Early Findings) to D. Misenheimer, US EPA, March 3, 2017.

Table 4-1. Estimated Time Requirements for Individual Sources Affected by the Final Rule

Industry	Emissions Source Group	Estimated Control Technology	Estimated Time Required (months)		
			Equipment Design / Fabrication / Installation	Analysis Phase / Permitting	Total Range
Cement and Concrete Product Manufacturing	Kilns	SNCR	11 - 12	6 - 12	17 - 24
Glass and Glass Product Manufacturing	Melting Furnaces	LNB	6 - 9	3 - 6	9 - 15
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	6 - 9	3 - 6	9 - 15
Pipeline Transportation of Natural Gas	RICE 2-Cycle	Layered Combustion	3 - 6	3 - 6	6 - 12
Pipeline Transportation of Natural Gas	RICE 4-Cycle Rich Burn	NSCR	3 - 6	3 - 6	6 - 12
Pipeline Transportation of Natural Gas	RICE unspecified	NSCR or Layered Combustion	3 - 6	3 - 6	6 - 12
Pipeline Transportation of Natural Gas	RICE 4-Cycle Lean Burn	SCR	7 - 13	3 - 6	10 - 19
Affected Non-EGU[a] Industries	Boilers	LNB + FGR	6 - 9	3 - 6	9 - 15
Affected Non-EGU[a] Industries	Boilers	SCR	8 - 13	6 - 12	14 - 25
Municipal Waste Management	MWC Boilers	LN[tm] + SNCR	16	6 - 12	22 - 28
Municipal Waste Management	MWC Boilers	ASNCR	11	6 - 12	17 – 23

[a] The affected non-EGU industries with boilers include Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

Based on contacts with state permitting staff, the time estimated in this report for permitting is conservatively long (that is, more likely to be overstated than understated).[72] The effort required to prepare and review air permit modifications for NOx control installations is much less than the effort required for the initial operating (Title V) permit. Most state permitting staff that offered information for this report indicated that permit modifications were likely to be processed in less than six months; and, for some states, expedited permitting programs are in place. These programs allow for a source to pay an additional fee to have their permit modification expedited. On the other hand, it is possible that some control installations may have the potential to trigger more complex reviews. In those instances,

[72] S. Roe, SC&A, Inc., personal communications with: L. Warden, Oklahoma Department of Environmental Quality, October 24, 2022; S. Short, Texas Commission on Environmental Quality, October 27, 2022; B. Johnston, Louisiana Department of Environmental Quality, October 25, 2022; and H. Bouchareb, Minnesota Pollution Control Agency, September 7, 2022.

the permit timelines indicated above are appropriate (including time required for public comment, if needed). For all NOx controls, except large SCR/SNCR applications, the estimated time required for analysis and permitting is 3 to 6 months. For large SCR/SNCR applications, the estimated time required is 6 to 12 months.

4.2 Issues Identified by Commenters Related to Timing

EPA solicited and received comments on the proposed rule related to the timing of control installations for non-EGU NOx sources. Often, commenters indicated that 36 months for installation of controls was not feasible, without identifying alternative timelines for achieving compliance.[73] However, while few commenters identified alternative control installation timelines, commenters identified several key issues that could impact the timeline. These are discussed below.

Supply Chain Concerns

Concerns expressed by regulated-industry commenters on access to NOx control technologies included the following:

- A limited pool of skilled installers: especially for combustion controls on RICE for natural gas transmission. Discussions with control equipment vendors have also indicated a limited pool of SNCR suppliers with MWC expertise. *Industries potentially impacted: Pipeline Transportation of Natural Gas and Solid Waste Incinerators and Combustors.*
- Competition among affected units to source control equipment vendors: for example, operators of ICI boilers and MWCs may have to compete with EGUs for SCR and SNCR vendors. A small number of EGU SCR retrofits are expected between 2023 and 2027 (2.6 - 8 GW of capacity). Also, the Agency estimates roughly 265 SCR and SNCR EGU optimization projects are expected within this time period. Given their much larger size and history with EGUs, commenters were concerned that some of these equipment vendors would focus attention first on affected EGUs. As a result, the size of the vendor pool available to service non-EGU affected units would be smaller. *Industries potentially impacted: Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, and Solid Waste Incinerators and Combustors.*
- General concern about long lead times for selected equipment vendors to design, fabricate and install control equipment. These comments did not offer specifics about the expected source(s) of equipment delays; however, they seem to stem from known production outages for control equipment components (such as those obtained from Chinese suppliers), transportation bottlenecks (including delays at US ports), and known current backlogs of North American equipment fabricators.

Supply chain issues and their potential to cause control installation delays are assessed in Section 5 of this report.

[73] For example, steel industry comment [EPA-HQ-OAR-2021-0668-0360. Comment submitted by JSW Steel (USA) Inc. and JSW Steel USA Ohio, Inc.]. Paper industry comment [EPA-HQ-OAR-2021-0668-0338. Comment submitted by Wisconsin Paper Council (WPC)], requests extension to the 2028 ozone season. Solid waste combustion (resource recovery) industry comment [EPA-HQ-OAR-2021-0668-0301. Comment submitted by Minnesota Resource Recovery Association (MRRA)].

Additional Issues

As mentioned previously, operators of furnaces used in glass manufacturing expressed concern about the need to install controls at an early point in the useful life of the furnace lining (refractory).[74] A number of commenters from the glass manufacturing industry said installing a control would require a cold shutdown of the furnace which would likely damage the refractory (furnaces are designed to run continuously between re-linings). Since a refractory might have a service life of 6 to 15 years, rule compliance extensions were requested of potentially many years beyond the May 2026 deadline (i.e., dependent on unit-specific circumstances).

While not a requirement of this final rule, commenters said some non-EGU coal-fired boiler operators and other non-EGUs may opt to switch to natural gas to achieve compliance. But these commenters said, if the natural gas infrastructure is not in place locally, additional time would likely be needed to bring natural gas to the site.[75]

4.3 Evaluation of Timing for Each Industry

This section includes an industry-specific assessment of the amount of time required for installation of each type of NOx control technology estimated to be installed in that industry to comply with the final rule. This discussion is focused on the time needed for an individual control technology installation. Note that the installation timing estimates presented in this section do not include the additional estimated time that could be needed assuming supply chain delays, which are discussed in Section 5. Section 4.4 provides an analysis of the timing needed to install NOx control technologies on all affected units (including EGU installations required by May 2026).

Cement and Concrete Product Manufacturing

Table 4-2 provides EPA's estimates of the NOx controls likely to be installed in the cement manufacturing industry and the number of affected units by emissions source group.76 A total of 16 SNCR systems are estimated to require installation, including both process and preheater/precalciner kilns.

Table 4-2. Potential Control Installations for Cement and Concrete Product Manufacturing

Emissions Source Group	Control Technology	Number of Units
Kiln- Dry Process	Selective Non-Catalytic Reduction	8
Preheater/Precalciner Kiln	Selective Non-Catalytic Reduction	4
Preheater Kiln	Selective Non-Catalytic Reduction	3
Kiln- Wet Process	Selective Non-Catalytic Reduction	1
	Total SNCR	***16***

[74] EPA-HQ-OAR-2021-0668-0406. Comment submitted by Ardagh Glass Inc. EPA-HQ-OAR-2021-0668-0548. Comment submitted by Glass Packaging Institute (GPI). EPA-HQ-OAR-2021-0668-0321. Comment submitted by Vitro Flat Glass LLC and Vitro Meadville Flat Glass, LLC.

[75] EPA-HQ-OAR-2021-0668-0320. Comment submitted by Genesis Alkali Wyoming, LP. EPA-HQ-OAR-2021-0668-0437. Comment submitted by American Forest & Paper Association (AF&PA).

[76] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

Although excessive on-off cycling of a cement kiln could also damage the refractory material (e.g., brick lining), some amount of cycling occurs in the industry for varying reasons.[77] Still, some consideration of timing for a kiln shutdown for the purposes of installing air pollution controls may be needed (i.e., timing to coincide with other preventive maintenance needs).

References on time for compliance are as follows without emission source group categorization. EPA's 2021 Non-EGU sectors TSD estimates the cement and concrete product manufacturing industry will take between 10-12 months for SNCR to be installed.[78] In the same TSD, EPA also noted an estimate of 19 months for SNCR applied to EGUs.[79] This latter estimate took into greater account the time needed for engineering, design, testing and permitting, albeit for an EGU application.

The Institute of Clean Air Companies (ICAC) timeline for installing SNCR is shown in Table 4-3 divided into phases (this information was also used in subsequent EPA timelines).[80] These values apply to industrial boilers, kilns, preheater kilns, and preheater/precalciner kilns. The total SNCR installation timeline is estimated to be 11 to 12 months as shown in Table 4-3. No consideration of the amount of time required for permitting was included in the ICAC timeline. Therefore, 6 to 12 months was added to the total time in Table 4-3 to accommodate this phase (this results in a conservatively long timeline, since permitting analyses may proceed concurrent with other phases). This results in a total timeline of 17 to 24 months. These values should be understood to reflect the time required for a single affected unit to apply the control.

Table 4-3. ICAC Timeline for SNCR Installation for Cement and Concrete Product Manufacturing[81]

Phase	Timeline (weeks)
1. Conceptual Studies / Design	2-4
2. Specifications / Vendor Bids / Financing	8-12
3. Construction Permit	--
4. Detailed Engineering / Fabrication	16
5. Site Work / Mobilization	--
6. Equipment Installation	8-12
7. Start-up / Testing	9
8. Operating Permit	--
Total time:	***11-12 months***
Total time, including permitting:	***17-24 months***

[77] Infinity for Cement Equipment, Kiln Refractory Requirement, Properties & Factors Affect Wear, website at https://feeco.com/rotary-kiln-refractory-preventative-care/.
[78] Page 87. Non-EGU Sectors TSD, Draft Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[79] Page 88 Non-EGU Sectors TSD, Draft Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[80] ICAC, 2006. Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006.
[81] Ibid.

Glass and Glass Product Manufacturing

Table 4-4 provides EPA's estimates for the NOx controls likely to be installed for the glass and glass products manufacturing industry.[82] A total of 61 LNB control installations are estimated for the industry, including container, pressed and blown, and flat glass processes.

Table 4-4. Potential Control Installations for Glass and Glass Product Manufacturing

Emissions Source Group	Control Technology	Number of Units
Container Glass: Melting Furnace	Low NOx Burner	36
Flat Glass: Melting Furnace	Low NOx Burner	12
Pressed and Blown Glass: Melting Furnace	Low NOx Burner	11
Furnace: General	Low NOx Burner	1
Unspecified	Low NOx Burner	1
	Total	***61***

Vitro Glass and other commenters stated that more than 36 months would be needed to install controls.[83] Supply chain delays, competition among affected units to procure and install controls, and time requirements for engineering and permitting were all mentioned as concerns. A complete shut-down of a glass furnace for NOx control installation requires a re-lining of the furnace (since the lining is damaged during cooling). A flat glass furnace might run continuously for 15 years between re-linings. Ardagh Glass indicated a 10-year timeframe for furnace re-bricking.[84] Commenters asked for flexibility to account for this issue, so that a manufacturer would not incur the cost of a re-lining well before the end of the useful life of the refractory.

As shown in Table 4-5, the expected installation timeline for installing LNB to glass furnaces is 9 to 15 months. This is based on general installation timelines for LNB or LNB+FGR applied to industrial sources of 6 to 9 months from ICAC[85] which are also documented in a 2017 EPA technical memorandum.[86] The total includes an additional 3 to 6 months to cover the conceptual studies/design and permitting phases (this is a conservatively long, or more likely an overstated estimate, since some of these phases may proceed concurrently). Based on discussions with state permitting staff, that amount of time should be sufficient to address situations where more complex permitting issues arise (e.g., PSD). The timeline in Table 4-5 reflects the time required to install LNB for a single affected unit.

[82] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.
[83] EPA-HQ-OAR-2021-0668-0321. Comment submitted by Vitro Flat Glass LLC and Vitro Meadville Flat Glass, LLC.
[84] EPA-HQ-OAR-2021-0668-0406. Comment submitted by Ardagh Glass Inc. Commenter referenced San Joaquin Valley Air Pollution Control District's Rule 4354, which allows for compliance deadlines based in part on furnace rebuilds.
[85] ICAC 2006. Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006.
[86] Lange, B., Eastern Research Group, Technical Memorandum (NOx APCD Installation Times Early Findings) to D. Misenheimer, US EPA, March 3, 2017.

Table 4-5. LNB or LNB+FGR Installation Timeline for Glass and Glass Products Manufacturing

Phase	Installation Timeline (weeks)
1. Conceptual Studies / Design	--
2. Specifications / Vendor Bids / Financing	6-10
3. Construction Permits	--
4. Detailed Engineering / Fabrication	6-9
5. Site Work / Mobilization	10-12
6. Equipment Installation	2-3
7. Start-up / Testing	1
8. Operating Permits	--
Total time:	***6 - 9 months***
Total time including permitting:	***9 – 15 months***

Iron and Steel Mills and Ferroalloy Manufacturing

Table 4-6 provides EPA's estimates for the NOx controls likely to be installed for reheat furnaces in the iron and steel and ferroalloy manufacturing industry based on analyses performed for the final rule.[87] There are 19 reheat furnaces in the iron and steel industry that are estimated to need combustion controls (LNB) to meet the applicable NOx control requirements.

Table 4-6. Potential Control Installations for Iron and Steel Mills and Ferroalloy Manufacturing

Emissions Source Group	Control Technology	Number of Units
Natural Gas: Reheat Furnaces	Low NOx Burners	19

The installation timeline for LNB on reheat furnaces is estimated to be the same as that shown above in Table 4-5 for other LNB installations.

Pipeline Transportation of Natural Gas

Table 4-7 provides EPA's estimates for the NOx controls likely to be installed for pipeline transportation of natural gas.[88] EPA has estimated the number of engines that may have to install controls according to the final rule cost analysis to be approximately 905. For 323 of these RICE, the combustion configuration was unknown, and those RICE are estimated to apply either NSCR or layered combustion.

[87] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

[88] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

Table 4-7. Potential Control Installations for Pipeline Transportation of Natural Gas

Emissions Source Group	Control Technology	Number of Units
2-cycle Lean Burn	Layered Combustion	394
4-cycle Rich Burn	Non-Selective Catalytic Reduction	30
Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion	323
4-cycle Lean Burn	Selective Catalytic Reduction	158
	Total	***905***

For pipeline transportation of natural gas, most of the comments pertaining to this industry addressed the time needed to implement combustion controls. Commenters stated that the 3-year timeframe for compliance with the proposed FIP was not technically feasible due to concerns about the supply chain (in particular, the size of the skilled labor pool with expertise in RICE retrofits), permitting backlogs due to the large number of potentially affected units, and the need to allow sufficient time for planning around taking compressors offline to avoid system reliability concerns (including the need to meet FERC pipeline pressure obligations by each compressor station).

In 2006, an air pollution controls association estimated that the amount of time required to conduct conceptual studies/engineering, develop specifications/vendor bids/financing, and equipment installation ranged from 2 to 3.5 months.[89] This is similar to a minimum time estimate from EPA of 3.5 months.[90]

Estimates for NOx control installation timing provided in industry comments to the proposed rule ranged from 21 months[91] to 60 months[92]. The higher estimates incorporate asserted expected delays from permitting or supply chain concerns (i.e., all affected units encounter delays). The ranges cover different control technologies (SCR, NSCR) and all engine types.[93]

Table 4-8 shows the estimated installation timelines for RICE SCR and NSCR/LC installation. The values in Table 4-8 apply to a single unit. An additional three to six months of time was added to both the EPA and ICAC timelines to account for permitting. This six-month estimate is based on contacts with permitting staff in multiple states. It represents a conservative (or lengthier) timeframe for these controls that should account for situations where more complex permitting issues arise (e.g., PSD). It is also

[89] Institute of Clean Air Companies (ICAC), "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources," December 2006.
[90] Eastern Research Group, "RICE Retrofits: Development Time for NOx Control Measures," Technical Memorandum to D. Misenheimer, US EPA, March 2017.
[91] EPA-HQ-OAR-2021-0668-0380. Comment submitted by TC Energy.
[92] EPA-HQ-OAR-2021-0668-0371. Comment submitted by INNIO Waukesha Gas Engines (INNIO Waukesha). While this commenter suggested allowing until May 1, 2028 for all installations to be completed, they also proposed phasing in the controls beginning two years from the effective date of the rule. The commenter suggested a six-year phase in from effective date; however, they also indicated that 48-60 months would be sufficient.

[93] We note that these estimates from commenters could not be independently verified for this report.

conservative (that is, likely overstates the needed timelines) because some of the phases identified in the timelines shown in Table 4-8 for both controls may proceed concurrently.

Table 4-8. Timeline for Installation of NOx Controls for RICE in Pipeline Transportation of Natural Gas

	Installation Timeline (weeks)	
	SCR	NSCR/LC
Phase	US EPA [94]	US EPA [95] and ICAC[96]
1. Conceptual Studies / Design	--	4-6
2. Specifications / Vendor Bids / Financing	6-8	2-4
3. Construction Permits	--	--
4. Detailed Engineering / Fabrication	6-16	4-6
5. Site Work / Mobilization	--	--
6. Equipment Installation	14-28	1-2 (US EPA) 2-4 (ICAC)
7. Start-up / Testing	2-6	1-2
8. Operating Permits	--	--
Total time:	***7 – 13 months***	***3 – 6 months***
Total time, including permitting:	***10 – 19 months***	***6 – 12 months***

Boilers in Affected Industries

Table 4-9 provides EPA's estimates for the NOx controls likely to be installed for boilers at industries affected by the final rule.[97] They are addressed collectively here, because the sources and control types are similar across industries. Generally, the sources are medium (10 – 100 million Btu/hr) and large boilers (>100 million Btu/hr) fired on a variety of gaseous, liquid, and solid fuels. Combustion controls estimated for rule compliance are mainly the application of low NOx burners with flue gas recirculation (151 total installations), while post-combustion controls are estimated to be SCR (15 total installations).

[94] Non-EGU Sectors TSD, Draft Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA-HQ-OAR-2021-0668, December 2021.
[95] Eastern Research Group, "RICE Retrofits: Development Time for NOx Control measures," Technical Memorandum to D. Misenheimer, US EPA, March 2017.
[96] Institute of Clean Air Companies, "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, Washington DC, December 4, 2006.
[97] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

Table 4-9. Potential Control Installations for Boilers in Affected Industries

Industry	Emissions Source Group	Control Technology	Number of Units
Basic Chemical Manufacturing	Boilers - Distillate Oil	Selective Catalytic Reduction	4
	Boilers - Natural Gas	Low NOx Burners and Flue Gas Recirculation	86
	Boilers - Natural Gas: Cogeneration	Low NOx Burners and Flue Gas Recirculation	1
	Boilers - Residual Oil	Selective Catalytic Reduction	1
	Boilers - Subbituminous Coal: Traveling Grate (Overfeed) Stoker	Selective Catalytic Reduction	1
Petroleum and Coal Products Manufacturing	Boilers - Natural Gas	Low NOx Burners and Flue Gas Recirculation	9
	Boilers - Natural Gas: Cogeneration	Low NOx Burners and Flue Gas Recirculation	1
	Boilers - Residual Oil	Low NOx Burners and Flue Gas Recirculation	4
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers - Coke Oven Gas/Natural Gas	Low NOx Burners and Flue Gas Recirculation	3
	Boilers - Natural Gas	Low NOx Burners and Flue Gas Recirculation	9
Metal Ore Mining	Boilers - Distillate Oil/ Natural Gas	Low NOx Burners and Flue Gas Recirculation	2
Pulp, Paper, and Paperboard Mills	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom	Selective Catalytic Reduction	1
	Boilers - Bituminous Coal: Spreader Stoker	Selective Catalytic Reduction	1
	Boilers - Coal: Dry Bottom	Selective Catalytic Reduction	4
	Boilers - Distillate Oil/Natural Gas	Selective Catalytic Reduction	2
	Boilers - Natural Gas	Low NOx Burners and Flue Gas Recirculation	32
	Boilers - Natural Gas/Bituminous Coal: Dry Bottom (Tangential)	Selective Catalytic Reduction	1
	Boilers - Natural Gas: Cogeneration	Low NOx Burners and Flue Gas Recirculation	2
	Boilers - Residual Oil /Natural Gas	Low NOx Burners and Flue Gas Recirculation	1
	Boilers - Residual Oil/Distillate Oil	Low NOx Burners and Flue Gas Recirculation	1
		Total Combustion Controls	***151***
		Total SCR	***15***

The timeline for installation of LNB+FGR to boilers in the affected industries is estimated to be the same as the values provided in Table 4-5 above (a total of 9-15 months).

According to EPA, the expected time needed to implement SCR controls on boilers in these industries is 8-13 months, as shown in Table 4-10.[98] An additional 6-12 months was also added to address permitting, which is a conservatively long estimate since permitting analyses may generally proceed concurrent with other phases.

Table 4-10. EPA's Estimated Potential Installation Timeline for Applying SCR to Boilers in the Affected Industries

	Installation Timeline (weeks)
Phase	**SCR [99]**
1. Conceptual Studies / Design	1-4
2. Specifications / Vendor Bids / Financing	5-8
3. Construction Permits	--
4. Detailed Engineering / Fabrication	4-6
5. Site Work / Mobilization	12-22
6. Equipment Installation	4-8
7. Start-up / Testing	5-10
8. Operating Permits	--
Total time:	***8 – 13 months***
Total time, including permitting:	***14 – 25 months***

Municipal Waste Combustion

As shown in Table 4-11, EPA has estimated that 57 MWCs may install ASNCR, with an additional four MWC units likely to install Covanta's low NOx combustion controls in combination with an existing SNCR system.[100]

[98] Lange, B., Eastern Research Group, Technical Memorandum (NOX APCD Installation Times Early Findings) to D. Misenheimer, US EPA, March 3, 2017. This estimate is believed to be based on an earlier ICAC estimate of 7 to 9 months for SCR applied to non-EGU sources. Institute of Clean Air Companies, "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, Washington DC, December 4, 2006.
[99] Lange, B., Eastern Research Group, Technical Memorandum (NO_X APCD Installation Times Early Findings) to D. Misenheimer, US EPA, March 3, 2017.
[100] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

Table 4-11. Potential Control Installations for MWCs

Emissions Source Group	Control Technology	Number of Units
MB/WW	ASNCR	43
MB/RC	ASNCR	9
MB/WW	LN^{tm} + SNCR	4
CLEERGAS gasification	ASNCR	1
RDF	ASNCR	4
	Total Combustion Controls	***4***
	Total ASNCR/SNCR	***61***

Beyond Plastics and other commenters provided a 2020 engineering study that assessed options for reducing NOx at an incinerator in Baltimore. The study evaluated options for technologies that could achieve a 24-hour limit of 110 ppm.[101] Table 4-12 summarizes the number of months estimated for each phase of the control installation, as well as the total project time. The report notes that permitting may add an additional 6 to 12 or more months to the total time (consistent with the permitting timeframes needed for large add-on controls at other sources discussed earlier).[102] This was a unit-specific study, so the installation timing for this or other units may be impacted by site-specific considerations.

The total time indicated for application of ASNCR is 17-23 months, which includes 6-12 months for permitting. The report did not include LN^{tm} + SNCR as one of the options evaluated. However, it did include FGR in combination with an existing SNCR system, which is the option that likely aligns most closely with LN^{tm} + SNCR. Therefore, this option is included in Table 4-12 with a total timeline of 22-28 months.

Table 4-12. Estimated Time by Phase for Control Installation Options for a Large MWC (months)

	Installation Timeline (months)	
Phase	ASNCR	FGR + Existing SNCR
1. Conceptual Studies / Design	3	4
2. Specifications / Vendor Bids / Financing	4	7
3. Construction Permits	--	--
4. Detailed Engineering / Fabrication	--	--
5. Site Work / Mobilization	3	4
6. Equipment Installation	2	3
7. Start-up / Testing	1	2
8. Operating Permits	--	--
Total time:	***11***	***16***
Total time, including permitting:	***17-23***	***22-28***

[101] EPA-HQ-OAR-2021-0668-0757. Comment submitted by Beyond Plastics, et. al.
[102] EPA-HQ-OAR-2021-0668-0757. Comment submitted by Beyond Plastics, et. al.

4.4 Cumulative Effect of Numerous Control Installations at Same Time on Timing and Demand for Materials and Services

Overlapping control requirements for the EGU and non-EGU sources may produce challenges for both the air pollution control industry (e.g., SCR fabricators) and other aligned trades (potentially catalyst material producers), including those tasked with manufacturing and installing structural components for large add-on controls. However, vendors have made statements that the availability of raw materials for fabrication may be increasing.[103]

Table 4-13 below summarizes the total number of potential non-EGU and EGU control installations estimated for compliance with the final rule.[104] An estimated 229 EGU SCR optimizations and 36 EGU SNCR optimizations are estimated by May 2026 for this rule. Also, EPA expects that 2.5-8 GW of EGU capacity may be in the process of applying SCR retrofits between 2023 and 2030. Assuming a nominal capacity of 500 MW, this represents a maximum of 16 EGU SCR retrofits. Since it is possible that the EGU SCR retrofits could occur by the 2026 or 2027 ozone season, they were added to the control installations shown in Table 4-13. The EGU SCR/SNCR optimizations are also included in the table because there is a potential for overlap in the need for skilled workers to address these optimizations and new non-EGU equipment installs (SCRs/SNCRs). For EGU SCR/SNCR optimizations, EPA expects that the vast majority of these will be accomplished by optimizing operations rather than a physical optimization (such as the addition of catalyst layers). Operational optimizations are expected to be completed by existing EGU personnel rather than equipment vendors.

Table 4-13. Potential Non-EGU and EGU Control Installations by the 2026 Ozone Season

Sector	Control Technology	Number of Installations*
Non-EGU	External Combustion - SCR	15
	External Combustion - SNCR/ASNCR	77
	External Combustion – Combustion Controls	231
	RICE – Compact SCR	158
	RICE - NSCR	192
	RICE - LC	555
	Total Non-EGU	**1,228**
EGU (through 2026)**	Optimize Existing SCR**	229
	Optimize Existing SNCR**	36
	SCR Retrofits	16
	Combustion Controls	10
	Total EGU	**291**
All Sectors	***New SCR + SCR Optimizations***	***260***
	SNCR/ASNCR + SNCR Optimizations	***113***

[103] Discussions with control equipment vendors have not indicated any current concerns for the availability of raw materials, such as plate or sheet steel, cement, etc., required for the fabrication of control equipment or the structural components for their installation. During the pandemic, delays were experienced by equipment fabricators for sheet stainless steel, but those delays have been alleviated.

[104] U.S. EPA, Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. Technical Memorandum, March 15, 2023.

	RICE NSCR	***192***
	RICE Compact SCR	***158***
	External Combustion Controls	***241***
	Internal Combustion Controls	***555***
	Total Non-EGU and EGU	***1,519***
*Note that for 323 RICE, EPA estimates these units to adopt either LC or NSCR. These control applications were assumed to breakdown 50:50 for representation in this table. Also, note that the EGU control counts only include applications in the states with estimated non-EGU controls (i.e., EGU controls for compliance in 2023 in Alabama, Minnesota, Nevada, and Wisconsin are not included here). **In most cases, optimization of existing SCR/SNCR controls means to employ practices to improve the removal rate for existing post-combustion controls such as adjusting the ammonia injection rate, or adding or regenerating catalyst more frequently, or changes in combustion unit operation or EGU dispatching to maintain optimal SCR exhaust temperatures.		

An estimated 905 RICE units in the natural gas transportation industry may have to install controls in order to comply with the final rule. The compact SCR and NSCR controls for RICE are supplied by a different set of vendors than those for non-EGU external combustion sources and EGUs. However, some overlap in demand for catalyst material (e.g., platinum) is expected among these affected sources.

One possible consideration for control installation timing indicated by the estimates in Table 4-13 above relate to overlapping requirements for SCR installation/optimization services:

- Number of potential SCR installations and optimizations across the EGU and non-EGU sectors: there is potential for competition for SCR EPC vendors, in particular for flue gas modeling and design services. However, based on discussions with SCR vendors, non-EGU design and installation services are handled by a different group of vendors than EGUs. Given the relatively small number of non-EGU installations required, there should be sufficient EPC support for non-EGUs to cover design and engineering services. A separate question is whether equipment fabricators can address an increase in demand for new SCR and SNCR installs in a timely manner. As further addressed in Section 5 of this report, equipment fabrication across North America experienced delay associated with supply chain disruption in the recent past. A discussion of the potential impacts of SCR catalyst requirements from EGU retrofit and optimization projects is provided later in this section.
- RICE SCR and NSCR applications: because there is expected to be some overlap in catalyst demand, the same question regarding catalyst material applies here as mentioned above. Different equipment vendors serve RICE than those above for external combustion sources, so there is no concern of overlapping demands.

Each of these areas is addressed in more detail below.

<u>Non-EGU SCR Installations and EGU SCR Optimizations</u>

While Table 4-13 above indicates a total of 418 SCR installations and optimizations across EGUs and non-EGUs (15 non-EGU external combustion sources, 158 RICE, 16 EGU SCR retrofits, and 229 EGU SCR optimizations), it is important to divide this total into applicable market segments. This is because different sets of vendors serve each segment:

- EGUs and large industrial systems: the vendor pool is largely made up of large, sometimes multi-national, companies that may be a sub-unit of power plant constructors (e.g., Babcock & Wilcox, General Electric, Mitsubishi Power Systems Americas). These vendors have sufficient size to take on the financial risk for SCR installations of this scale (e.g., hundreds of MW EGU or very large industrial boilers). This pool of vendors generally designs the system, and then manages the subcontracted fabrication and installation phases (so, this pool is referred to here as engineering, procurement and construction or EPC contractors). An on-line survey and discussions with some vendors indicate that there are about 10 vendors in this pool in the US market.[105] It is important to note that vendors indicated that perhaps only half of these large vendors do the design work and manage the fabrication and installation. The rest of the vendors subcontract out all phases. Appendix A provides a listing of SCR and SNCR vendors with a focus on North American companies. There may be additional European or Asian (especially Japanese) vendors serving the North American market. The pool of EPCs may help address a small number of EGU SCR optimizations noted above (however, in most cases the EGU operator will likely undertake optimizations without EPC support); but is not expected to pursue smaller non-EGU systems, such as those that EPA estimates for non-EGU boilers.
- Smaller industrial systems: this pool includes a larger number of vendors serving the industrial sector and smaller EGUs, such as natural gas turbine plants. These vendors may handle all phases of SCR design, fabrication, and installation. There appears to be at least 12 vendors for this pool in the US market (see Appendix A). Given the size of this vendor pool, operators of the 15 affected non-EGU units needing SCR should have ample access to vendor support.
- Compact SCR systems: seven vendors were identified that provide compact systems for internal combustion engines (see Appendix A). These vendors appear to offer all phases of compact SCR design, fabrication, and installation.

Skilled Labor. A discussion of available skilled labor for the design phases of SCR systems is presented below. Section 5 provides an assessment of the fabrication and installation labor needed.

Large system vendors typically handle all the major phases of SCR installation through EPC contracts. This includes SCR design, fabrication, and installation. Regarding the fabrication and installation work, much of that is subcontracted out to equipment fabricators and local construction companies. SCR contacts have indicated that, currently, their staffing levels might support the design and installation of a half dozen or so systems per year (EGU-sized systems). This compares to twenty or more projects per year in the late 1990s by the largest vendors to address the demand spurred by the NOx SIP Call. The relative lack of large SCR projects during the last ten or more years led to a contraction in the number of vendors and their staffing levels. Vendors were reluctant to suggest that the air pollution control industry could not quickly respond to a surge in demand, and that, for some companies, additional

[105] A&WMA Buyers Guide, website at https://awmabuyersguide.com/. Air Pollution Control Equipment Manufacturers Listings, An Authoritative List of the Best Air Pollution Control Equipment, website at https://www.airpollutioncontrolequipment.com/more-air-pollution-control-equipment-manufacturers-listings/. Institute of Clean Air Companies, ICAC Members, website at https://www.icac.com/page/Members. T. Licata, Licata Energy & Environmental Consultants, Inc., personal communication with S. Roe, SC&A, Inc., September 2022. D. Harajda, Mitsubishi Power Systems Americas, Inc., personal communication with S. Roe, SC&A, Inc., September 2022. F. Collinsworth, CECO Environmental, personal communication with S. Roe, SC&A, Inc., September 2022. B. Gretta, SCR Solutions, personal communication with S. Roe, SC&A, Inc., October 2022. R. Sadler, Catalytic Combustion, Inc., personal communication with S. Roe, SC&A, Inc., October 2022.

system design support could be leveraged from overseas staff.[106] In addition to US fabricators, large SCR system vendors use equipment fabricators in Canada and Mexico, when needed. As noted above, EPA does expect a relatively small amount of EGU capacity to be retrofit with SCR between 2023 and 2027 (2.5 - 8 GW of capacity or 16 units). However, given the fact that this pool of large system vendors is not expected to serve the affected non-EGU sources, and that EPA estimates only 15 non-EGU SCR systems will be installed for compliance with the final rule, significant competition for skilled designers of non-EGU SCR systems is not expected.

In addition, regarding EGU SCR optimizations, discussions with SCR vendors indicate that most EGUs may want to use the original equipment manufacturer (OEM) to conduct these optimizations (the OEM here meaning the builder of the power plant). Thus, SCR vendor support would only be needed for a very small number of the total 229 EGU optimizations estimated by EPA, since most optimizations will be done through operational changes conducted by plant staff. Moreover, 2022 data from EGU sources with existing SCRs illustrates that optimization has already occurred at many sources and future optimization is just a continuation of scheduled routine maintenance and operation for most sources, and does not constitute unplanned, incremental demand on system resources in these cases. Complementing this notion, EPA's assumptions for deriving emission performance consistent with optimization utilizes a methodology that allows for routine – rather than increased – catalyst replacement. The pool of qualified vendors is much larger than just these OEMs. It includes smaller SCR system vendors and architectural and engineering firms with power sector expertise. Where physical optimizations are employed, they could range from simple catalyst upgrades or additions of catalyst layers or to upgrades of the reagent mixing systems and/or ammonia flow control units.[107] Those requiring enhanced mixing would require vendors with flow modeling expertise (generally, the large SCR vendor pool). Again, EPA's expectations for EGU optimizations are that the vast majority of these will be operational optimizations, including more frequent maintenance, or changes to the operation of the combustion unit or dispatching of the EGU to maintain optimal exhaust temperatures for the SCR. These are changes that will not place additional demand on the skilled labor pool.

For non-EGUs, EPA has estimated that 15 SCR systems, excluding compact SCR systems that are expected to be applied to natural gas compressor engines, will likely be installed. The 12 or so vendors of the small SCR vendor pool may need to be able to design/fabricate/install on average 1 or 2 SCR systems prior to May 2026. Based on discussions with vendors, the number of new systems should easily be designed and engineered within 1 to 2 years. Equipment fabrication and installation should also be completed during the timelines indicated above barring delays in fabrication or raw materials supply. More information on indicators for fabrication activity are provided in Section 5.

EPA estimates that another 77 SNCR/ASNCRs will likely be installed for non-EGU affected units with about three quarters of those being MSW combustors. Nine SNCR vendors were identified from an internet search that serve the North American market (see Appendix A). At least three of these also provide ASNCR based on information from their websites. If all 77 installations are distributed among the SNCR system vendors, on average, each would need to have the capacity to design, fabricate and install 8 to 9 SNCR/ASNCR systems within a three-year period (or 2 to 3 each per year). Based on

[106] For example, Mitsubishi Power Systems Americas also have SCR designers in Japan.
[107] D. Harajda, Mitsubishi Power Systems Americas, personal communication with S. Roe, SC&A, Inc., September 2022.

discussions with system vendors, this number of new installations should be achievable for the control industry.

One potential complicating factor related to the number of estimated new non-EGU SNCR/ASNCR installations is that 61 are in the municipal waste combustion industry. Not all the vendors listed in Appendix A may have expertise working with MWCs, and this could reduce the size of the vendor pool. If the pool with MWC expertise is assumed to be only 3 to 5 vendors, then on average, each would need to install 12 to 20 systems by May 2026. This number of installations per vendor could be difficult for vendors to support based on discussions with control equipment vendors, which suggested that 3 to 5 systems per year is the capacity for some vendors. If, on the other hand, a larger number of vendors have or gain sufficient expertise to work with MWCs, then the number of installations requested of each vendor would be reduced, and the vendor pool may be able to support the demand for new SNCR/ASNCR installations at MWCs by May 2026.

For compact SCR and NSCR systems applied to RICE, feedback from one system supplier did not indicate a significant concern for the air pollution control industry to meet the demand for the estimated 350 systems by May 2026.[108] This is because of the influence of the construction of data centers in recent years. Many diesel- and natural gas-powered RICE have been installed at data centers in recent years for backup power, and many of these have required SCR. A single large data center could require dozens of compact SCR systems. Therefore, the contact believed that an additional demand of several hundred compact SCR systems over a 3-year period would not be difficult for the industry to meet.

Availability of Raw Materials. Discussions with control equipment vendors did not uncover any concerns regarding the availability of raw materials needed to fabricate and install NOx controls (e.g., sheet or plate steel, cement). Some concerns were raised in comments by a large-scale SCR OEM and catalyst supplier about the availability of sufficient catalyst to cover all the new SCR systems and optimizations.[109] A 600 MW EGU might have 3 to 4 layers of catalyst of 300 cubic meters (m^3) each. A single SCR optimization project could involve the addition of another layer, or it could involve a complete change-out of catalyst. It is anticipated that most of the 229 EGU SCR optimizations will have been conducted by the 2023 ozone season. In addition, it is anticipated that a small number of EGUs will retrofit SCR (new system installs) on 2.5 – 8 GW (potentially up to 16 EGUs at 500 MW capacity) by the 2026 or 2027 ozone season.[110] EGU SCR "optimizations" cover an array of operational or physical alterations:

- Operational optimizations: these can be made without any physical alterations to the source or SCR system and include increasing maintenance, optimizing reagent injection, or changing combustion conditions to assure that the exhaust is meeting optimal temperatures for the SCR system (e.g., assuring that the EGU is dispatch schedule maintains adequate exhaust temperature);

[108] R. Sadler, Catalytic Combustion, personal communication with S. Roe, SC&A, Inc., October 10, 2022.
[109] D. Harajda, Mitsubishi Power Americas, personal communication with S. Roe, SC&A, Inc., October 27, 2022.
[110] U.S. EPA, "EGU NOx Mitigation Strategies Final Rule TSD," Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668, March 2023.

- Physical optimizations: these include a complete change-out of catalyst material or the addition of another catalyst layer.

Depending on the number of EGU operators that elect physical optimizations to their SCR systems, a short-term spike in demand for catalyst material could be a concern. However, very few EGU operators are expected to elect to conduct physical optimizations. We were unable to source sufficient information from catalyst suppliers to gauge the significance of these new demands including the potential length of any associated supply chain delay.

The information reviewed indicates that any resulting increase in catalyst demand can easily be met via new production and/or the recycling of catalyst material from retired EGUs equipped with SCR. It can be noted that roughly 24 GW of EGUs with SCR are currently planning to retire (or have retired) between Jan 2021 and May 2026.[111] This would lower demand for catalyst, likely significantly more than any increased demand from EGU SCR optimization or retrofits and the non-EGU new SCR installs addressed in this report. In addition, the catalyst material from these retired units will be available for recycling (reducing the need to source new raw materials).

RICE NOx Combustion Control Installations

EPA has estimated for the final rule that layered combustion (LC) installations could be from 394 to 717 affected units out of a total of an estimated 905 engines anticipated to install some form of NOx control. The higher end of the range addresses compressor engines for which EPA did not have details on engine cycle; depending on configuration, operators could apply either LC or NSCR.

4.5 Control Vendor Demand/Capacity

Industry commenters on the rule stated a concern about vendor capacity in terms of the availability of SCR or SNCR manufacturers to simultaneously meet the needs of both EGU and non-EGU sources affected by the rule. Table 4-14 provides a summary of the number of EGU and non-EGUs estimated to install either SCR or SNCR. Note that these exclude compact SCR systems applied to RICE. An internet search identified over 20 companies operating in the US that provide SCR design/construction/installation (see Appendix A). At least nine of these serve the large EGU market (coal-fired power plants) and smaller EGUs (e.g., natural gas turbine plants). The others serve small EGUs and non-EGU sources. Nine SNCR vendors were identified that serve the US market.

As indicated in Table 4-14, a potential for overlap exists between EGU and non-EGU sector projects. As indicated by the estimated number of SCR/SNCR applications per vendor in Table 4-14, for large-scale SCR systems, the estimated 5 to 16 SCR retrofits for EGUs could be addressed by a vendor pool of at least nine identified by EPA. We do not display optimizations in the table below because EPA expects that many of these optimizations can be accomplished through in-house labor and in a relatively short time period (about 2 months based on past experience). Additionally, these optimizations are expected to occur by the 2023 ozone season.

[111] EPA "Appendix A: Final Rule State Emission Budget Calculations and Engineering Analytics" of Ozone Transport Policy Analysis Final Rule TSD.

Table 4-14. Estimated Demand for SCR or SNCR Projects by 2026

Parameter	Large-Scale SCR	Small-Scale SCR	SNCR / ASNCR	Applications per Vendor
Equipment Vendors	**9**	**14**	**9**	
Estimated Applications				
EGU SCR (~2.5 – 8 GW by 2027)	5 – 16*			~0.5-2
Affected Industry Boiler SCR Installs		15		~1
Cement Kiln SNCR Installs			16	~2
MWC SNCR/ASNCR Installs			61	~7

*Based on an assumed nominal 500 MW average unit capacity.

For small-scale SCR applied to non-EGU boilers, the applications per vendor presume that only the remaining small-scale SCR vendors are the available pool of suppliers (i.e., that large system providers are not interested in systems of that scale). This results in only around 1 application per vendor. Total non-EGU SNCR/ASNCR applications per vendor total 9. Over a 3-year period, this suggests that each vendor might have around 3 applications per year, which is within the typical capacity constraints suggested during vendor contacts.

We find that there are at least nine companies offering SNCR systems in the US (see Appendix A). Between EGU SNCR optimizations and non-EGU SNCR installations, the average number of applications per vendor is 13. Spread across 2 years (assuming another year for initial studies and permitting as mentioned in earlier in Section 4), this average becomes 7 per vendor per year. However, as noted above, a majority of the EGU SNCR optimizations are not expected to require vendor support, so the 7 applications per vendor per year is likely a maximum estimate, with a more likely estimate being 4 applications per vendor per year if the EGU optimizations are excluded. Note that the MWC applications will likely be drawing from a smaller pool of vendors than the 9 indicated, however. This is because not all SNCR vendors will have the expertise with MWCs (including those that have designed and installed ASNCR). Therefore, MWC SNCR installs may have an increased risk for supply chain delays associated with sourcing the skilled labor required to meet a May 2026 deadline.

Note that compact SCR and NSCR applied to RICE are not addressed in Table 4-14, since those are supplied primarily by a different set of vendors than the larger EGU and non-EGU systems. As indicated previously, the number of vendors for those systems appears to be sufficient based on vendor discussions.

4.6 Permitting Processes

As shown in Table 4-1, the typical time needed to obtain construction and operating permits for non-EGU NOx control installations is estimated to be 3-6 months for some industry/control source combinations and 6-12 months for other, more complex permits (e.g., SCR or SNCR). The Table 4-1 estimates of the amount of time required for permit reviews included in the installation timelines is conservative (that is, overstated), so that complex permitting issues can be addressed, where needed. This section provides an analysis of the permitting load that could occur by state based on the number and type of control installations estimated in each state. This informs our assessment of whether the permitting load in any covered state might overwhelm existing permitting staff and pose a risk of delay in control installations.

For states that have permitting programs that allow for expedited review, the permitting processes may be less of a concern. Especially in situations where emission reductions from existing sources are involved (rather than new sources of emissions), minor permit revisions can often be granted within 8 weeks if not sooner.[112]

A key permitting issue for any control installation is whether the change to the source is considered a minor or major modification to the existing permit. Installation of a NOx control will not always trigger substantive permit reviews. For example, if a combustion control retrofit kit is being installed on a RICE and does not lead to any increase in emissions, the owner/operator may only need a minor permit modification. Installation of a NOx control device that results in a significant increase in emissions of another regulated pollutant, however, would constitute a major modification to the source requiring a lengthier major NNSR or PSD permitting process.

Contacts with permitting agency staff in several states provided the following information relevant to estimating the timelines needed for non-EGU sources to obtain the permits necessary to comply with the final rule:

- Louisiana: Minor permit revisions take about 40 hours. Louisiana Department of Environmental Quality's current staffing includes 46 permitting staff.[113]
- Texas: The Texas Commission on Environmental Quality (TCEQ) has around 90 permitting staff,[114] and has a target of completing operating permit modifications within 120 days.[115] The number of ongoing permitting projects in Texas are 974, and the state is keeping up with the current workload based on information available for this report.
- Oklahoma: Permitting staff indicated that their estimate of affected units was 109, and that these were located at around 40 facilities.[116] The Oklahoma Department of Environmental Quality currently has 15 permitting staff and three open positions.

Table 4-15 provides a summary of the estimated number of non-EGU NOx control installations by state.[117] The controls are broken out by large add-on controls (SCR or SNCR) and other NOx controls. The latter include NSCR and compact SCR applied to RICE and combustion controls (layered combustion, LNB, LNB + FGR). The number of control installations were broken down into these two categories since

[112] B. Johnston, Louisiana Department of Environmental Quality (LDEQ), personal communication with S. Roe, SC&A, Inc., October 25, 2022. Based on the number and type of affected units, LDEQ felt confident that ATCs could be issued in a timely manner that would not impact an operator from meeting the compliance schedule indicated in the proposed rule.

[113] B. Johnston, Louisiana Department of Environmental Quality (LDEQ), personal communication with S. Roe, SC&A, Inc., October 25, 2022. Based on the number and type of affected units, LDEQ felt confident that ATCs could be issued in a timely manner that would not impact an operator from meeting the compliance schedule indicated in the proposed rule.

[114] S. Short, Acting Director, Office of Air, Texas Commission on Environmental Quality, personal communication with S. Roe, SC&A, Inc., October 31, 2022.

[115] This target is for the alteration of a new source review permit. TCEQ also mentioned a target of 330 days for revision of a general operating permit or 365 days for revision of a site operating permit. Source: Short, S. Acting Director, Office of Air, TCEQ, personal communication with S. Roe, SC&A, Inc., October 27, 2022.

[116] L. Warden, Engineering and Permitting Group Manager, OKDEQ, personal communication with S. Roe, SC&A, Inc., October 24, 2022.

[117] EPA, Office of Air Quality Planning and Standards, "Non-EGU Unit Results – Scenarios – 12-01-2022.xlsx."

large add-on controls may require more time by permit reviewers than combustion controls or packaged add-on controls.

Table 4-15 also includes an indication of whether a state has an expedited permit review process available. Most state expedited permitting programs allow a source operator to pay an additional fee to have their permit or permit revision processed on an expedited manner. Additionally, some states have other requirements for expedited review, such as the unit owner or operator being a member of an environmental stewardship program.

Finally, Table 4-15 provides an estimate of the incremental state permitting staff load that might result from the non-EGU controls needed to comply with the final rule. This is estimated in terms of annual staff full time equivalent (FTE) hours, with 2,000 hours assumed to be a typical FTE workload per year. The state incremental FTE permitting load is calculated as 400 hours per major modification (based on the information provided by Minnesota)[118] and 40 hours per minor modification (based on the information provided by Louisiana), with each multiplied by the number of expected units needing permits in each category. The resulting total incremental permit hour burden is divided by 2,000 hours per FTE and by 2 years, since there will be approximately 2 years during which these permits might be processed.

Table 4-15. Estimated Non-EGU NOx Control Installations by 2026 by State

State (Expedited Program?)	SCR / SNCR (Major Modification)	Other NOx Controls (Minor Modification)	Total	Estimated Annual FTE increment*
Arkansas (N)	2	32	34	0.5
California (Y)	6	7	13	0.7
Illinois (Y)	0	61	61	0.6
Indiana (Y)	7	44	51	1.1
Kentucky (Y)	0	48	48	0.5
Louisiana (Y)	4	195	199	2.4
Maryland (N)	0	2	2	0.0
Michigan (N)	3	58	61	0.9
Mississippi (N)	0	63	63	0.6
Missouri (N)	1	39	40	0.5
New Jersey (N)	10	1	11	1.0
New York (N)	18	12	30	1.9
Ohio (N)	2	108	110	1.3
Oklahoma (N)	9	126	135	2.2
Pennsylvania (N)	21	66	87	2.8
Texas (Y)	1	176	177	1.9
Utah (N)	0	6	6	0.1
Virginia (N)	8	29	37	1.1

118 Sources in Minnesota were included in the proposed rule, but not in the final rule.

State (Expedited Program?)	SCR / SNCR (Major Modification)	Other NOx Controls (Minor Modification)	Total	Estimated Annual FTE increment*
West Virginia (N)	0	63	63	0.6
Totals	**92**	**1,136**	**1,228**	**21**

***Estimated as 400 hours per major modification, 40 hours per minor modification, with 2,000 hours per FTE per year, and with 2 years available.

With the number of staff present in Louisiana, the Table 4-15 incremental FTE of 2.4 represents about a 5% increase in workload. We anticipate that this incremental workload increase can be accommodated in Louisiana. Note this number of affected units represents an upper end to the number of permit modifications needed to support the rule as some sources may have more than one affected unit and will likely seek permit modifications for them at the same time.

Even though the number of estimated NOx control installations for Texas is high, a large fraction of these is for controls on natural gas-fired compression engines (RICE). TCEQ staff has indicated it can address the expected increase in permit workload for non-EGUs.[119] Assuming that the bulk of permits need to be processed within a two-year period, roughly a 2% increase in permit staffing workload, or a 9% increase in ongoing permit workload is estimated to result from the final rule. We anticipate that this incremental workload increase can be addressed.

In Oklahoma, it appears there may be an incremental increase in permit review labor associated with permit modification reviews of around 12 to 15% (depending on whether Oklahoma has 15 or 18 permitting staff). Oklahoma permitting staff could face a relatively higher permitting load on a per-FTE basis. However, as in Texas, many of the units in Oklahoma are RICE and thus not likely to trigger major modification review.

Available time and resources did not allow for permitting staff levels to be collected from each affected state to conduct similar assessments to the analyses above for Louisiana, Texas, and Oklahoma. Based on the state-specific assessments above, all of the incremental FTE estimates associated with permitting appear to be manageable, as all are less than 3 FTE per year. Thus, no additional delays are attributed to permitting beyond the standard timeframe needed for permitting as listed in Table 4-1.

Note that the permitting load from EGU controls was not included in this assessment, as only a handful of NOx retrofit controls (beyond optimizations of existing controls) are expected in compliance with the final rule by 2026. As indicated in Section 4, the total number of expected EGU SCR retrofits and combustion control installs is estimated to be between 15 and 50. Spread across all states affected by the rule, the incremental permitting workload is expected to be small. In addition, we anticipate that the vast majority of EGU SCR/SNCR optimizations will be completed in-house with operational changes that will not affect the operation of the existing control equipment. Rather, the operational changes will be mainly increased maintenance, changes to combustion unit operation, or changes in EGU dispatching (that maintain exhaust at optimal temperatures for control operation). It is assumed that these

[119] S. Short, Acting Director, Office of Air, Texas Commission on Environmental Quality, personal communication with S. Roe, SC&A, Inc., October 31, 2022.

operational changes are all within the conditions of the existing operating permit and no revisions will be required.

5. Potential for Supply Chain Delays and Constraints

5.1 Supply Chain Concerns

Supply chain concerns can be organized into the following three phases of control equipment installation:

1. Producer constraints in raw materials and control equipment component production. Raw materials include bar and plate steel and catalyst components. Note that bar and plate steel products are manufactured by an industry addressed by the final rule.

2. Shipping delays for raw materials and components (especially imported components). Examples of control equipment components are pumps, nozzles, fans, motors, and electronic controllers.

3. Constraints in the skilled labor pools involved in control equipment design, fabrication, and installation. Depending on NOx control type and application, the skilled labor pool could include the initial system modelers and equipment designers, equipment fabricators, control equipment installers, and other local construction trades needed for control installation (e.g., equipment foundations, structural supports).

Producer constraints in raw materials and control equipment components were identified as concerns by both commenters and control equipment vendors. One of the raw materials of concern was catalyst material for SCR systems (including oxides of base metals and various precious metals). As described in Section 4.4, while there are overlapping needs for catalyst material for both the EGU and non-EGU sectors, EPA expects that the incremental demands will be small, and that additional catalyst material will be available for recycling due to recent and ongoing EGU retirements.

Based on input from control equipment vendors, demand constraints brought on by the pandemic for bar and plate steel and equipment components (e.g., nozzles, pumps, fans, controllers) were easing in the final quarter of 2022. Vendor expectations are that any remaining producer constraints will resolve during 2023. Also, based on November 2022 statistics presented below (Figure 5-1) from the Bureau of Transportation Statistics, business inventories are trending back toward pre-pandemic levels.

Statistics presented below also indicate that shipping delays that occurred during the pandemic are abating (Figures 5-2 through 5-8). These include statistics on shipping, truck activity and more generalized supply chain indices.

Available statistics for the skilled labor pools needed for control equipment fabrication indicate a high level of capacity utilization for the US, especially for the fabricated metals sector which includes manufacturers involved in constructing many add-on controls (Figure 5--9). Other fabricators in Canada and Mexico are also commonly used by US control equipment vendors. While the data for Mexico are not presented at the same level of detail as the US statistics, they indicate high levels of capacity utilization in the manufacturing sectors of both countries (Figures 5-10 and 5-11). This supports feedback from some equipment vendors about long lead times (> 12 months) experienced during 2022.

Section 5.2 below addresses the potential for constraints in local installation labor. These are the specialty contractors that might be needed for construction of large add-on controls, such as SCR or SNCR. As indicated by those statistics, some states have still not recovered in terms of employment levels of specialty contractors. Although the number of large add-on controls for the non-EGU sector is small as addressed elsewhere in this report, these statistics indicate that there could be some localized challenges in sourcing installation labor. However, no analysis was undertaken of the capacity for labor mobility for control installation projects.

Information gathered to characterize each of the three areas of supply chain concern and related comments are summarized below.

Potential Producer Constraints for NOx Control Equipment Components and Associated Raw Materials

Comments were due on the proposed rule by June of 2022, and so commenters discussed their experience or perception of these supply-chain issues as of that time period. As discussed further below, recent economic indicators suggest some of these concerns are ameliorating.

In their comments on the proposed rule, CIBO noted current delays in the delivery of specialized parts for SCR systems (which may also affect other control types). These include variable frequency drives, programmable logic controllers, and ammonia pumps.[120] The lead time for variable frequency drives was cited as being around 1 year as compared to a year ago (from when these comments were submitted) when these drives were available off the shelf or had a lead time of around 1 month. Similarly, according to this commenter, typical lead times for ammonia pumps were 18 months in the pre-Covid era but were around 24 months at the time the comment was submitted.

Control equipment vendors have also reported delays in components that are typically imported: electronic control equipment, nozzles, and pumps. Many of these parts are imported from Asia (especially Taiwan and China). However, the situation seems to be improving, and one vendor expected that the supply delays may be resolved sometime in 2023.

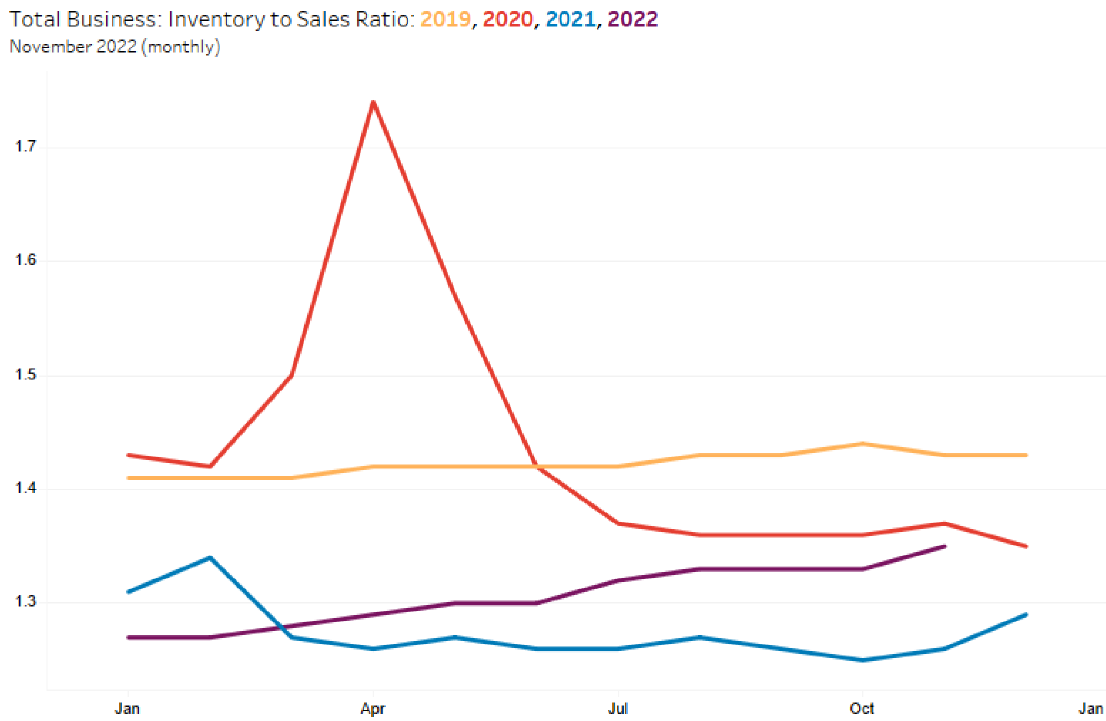
The Utah Petroleum Association/Utah Mining Association commented that lead times for combustor and controller parts had increased from 40 weeks to 80 – 120 weeks, as of the time the comment was submitted.[121] They also commented that skilled labor shortages are expected, especially in rural areas. The commenter also mentioned that more NOx reductions and other environmental benefits could be obtained by extending electricity system distribution, so that electrification could become a compliance option.

The Associated General Contractors of America commented that current lead times for procurement of certain construction materials could impact the timelines for various industries subject to the proposed rule.[122] Examples mentioned were six-month lead times for fittings used in water supply systems and lead times of over a year for aluminum used in metal fabrication of bridges. Some of these construction materials would also be used to support large NOx control systems.

Regarding component supplies from U.S. manufacturers, Figure 5--1 below shows the inventory to sales ratio for US business through September 2022.[123] These data from the Bureau of Transportation

[120] EPA-HQ-OAR-2021-0668-0362. Comment submitted by Council of Industrial Boiler Owners (CIBO).
[121] EPA-HQ-OAR-2021-0668-0378. Comment submitted by Utah Petroleum Association (UPA) and Utah Mining Association (UMA).
[122] EPA-HQ-OAR-2021-0668-0415. Comment submitted by Associated General Contractors of America (AGC).
[123] Bureau of Transportation Statistics (BTS), Latest Supply Chain Indicators, website at https://www.bts.gov/freight-indicators#labor. The ratio of total inventory at retailers, wholesalers, and

Statistics (BTS) indicate that business inventories are improving relative to 2021; however, inventory levels have still not yet returned to pre-pandemic levels (2019).



Notes: The ratio of total inventory at retailers, wholesalers, and manufacturers, divided by total sales. Data on inventory and sales are based on Census Bureau surveys. Data adjusted for seasonal, holiday and trading day differences but not for price changes.
Source: U.S. Census Bureau, Total Business: Inventories to Sales Ratio

Figure 5-1. US Inventory to Sales Ratio

Shipping Delays for Raw Materials and Control Equipment Components

National indicators of shipping constraints from BTS indicate a mixed picture of economic recovery following the pandemic. Figure 5-2 shows that the number of container ships awaiting berth at US ports has improved somewhat over the past year at two of the four ports reported; however, overall, the number of ships remains high (about 90 at all US ports) with only a small reduction overall in the past year.

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manufacturers, divided by total sales. Data on inventory and sales are based on Census Bureau surveys. Data adjusted for seasonal, holiday and trading day differences but not for price changes.

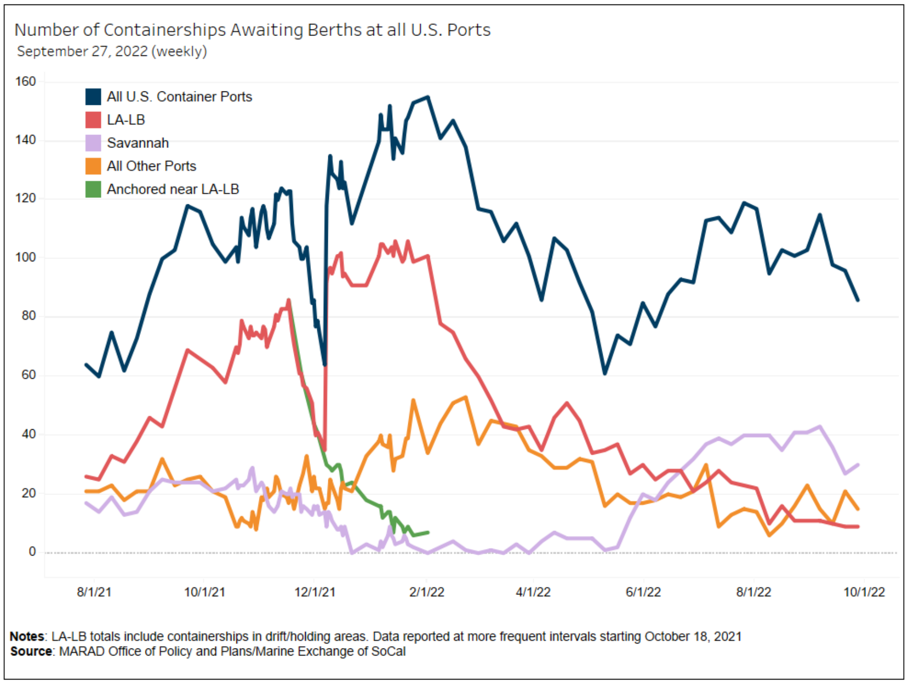

Figure 5-2. Containerships Awaiting Berth

For truck freight activity, the BTS data in Figure 5-3 below show that truck travel activity has returned to pre-pandemic levels. The BTS freight transportation services index through September 2022 shown in Figure 5-4 also indicates that services have recovered to near or above 2019 levels.

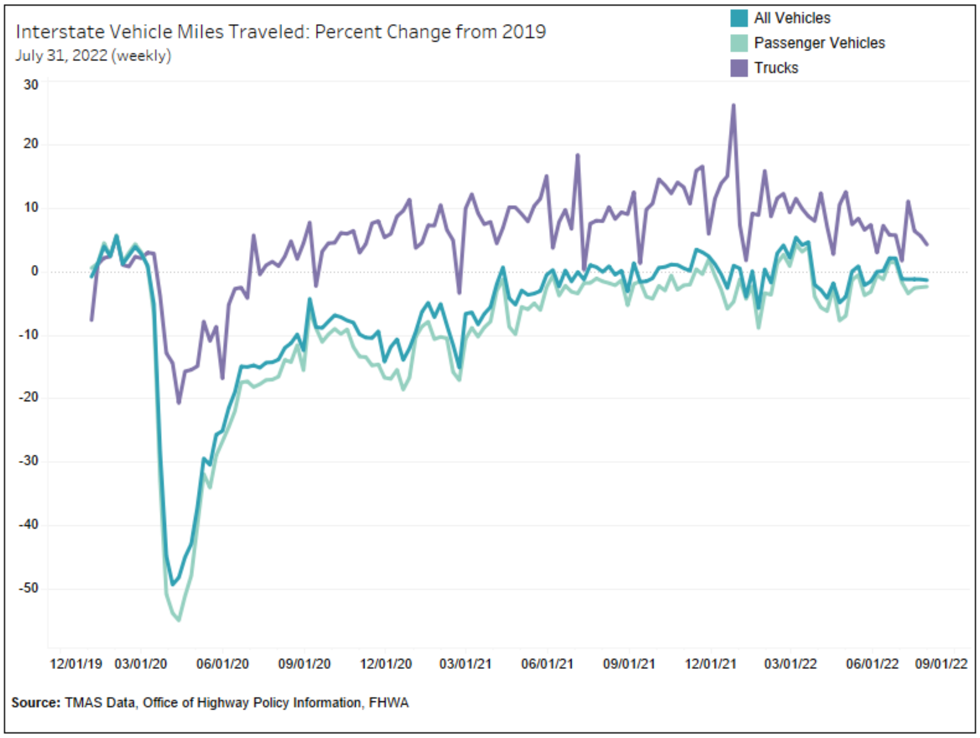

Figure 5-3. Interstate Vehicle-Miles Traveled (% Change from 2019)

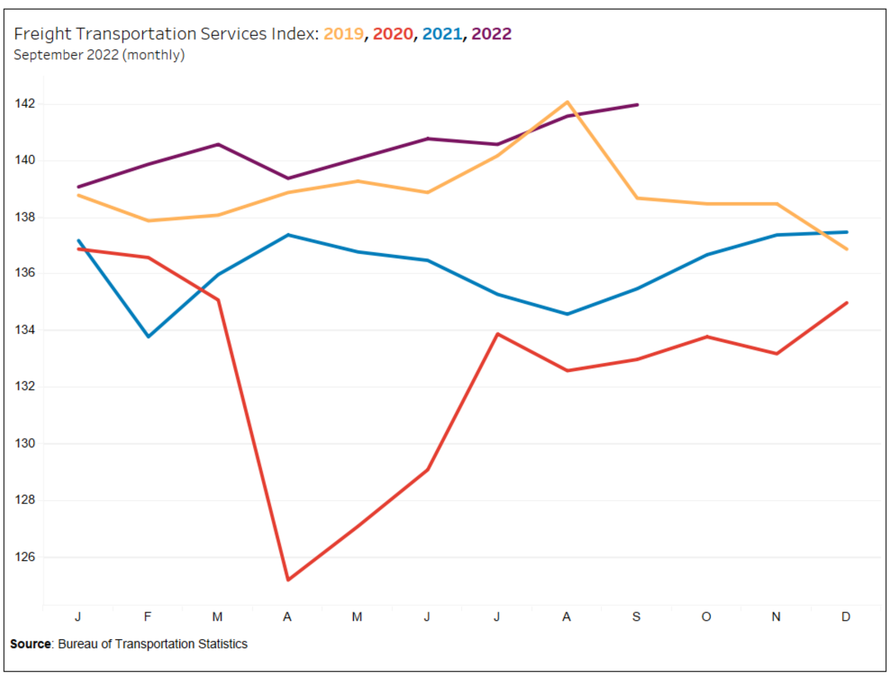

Figure 5-4. Freight Transportation Services Index

While the indicators above show that the transport of goods has largely returned to more normal levels, Figure 5-5 below shows another BTS indicator on the volume of imported goods, which is now well above pre-pandemic levels. Hence, there still seems to be strong potential for more freight delays for imported goods, although the imported goods appear to be heading back to more historic or normal levels.

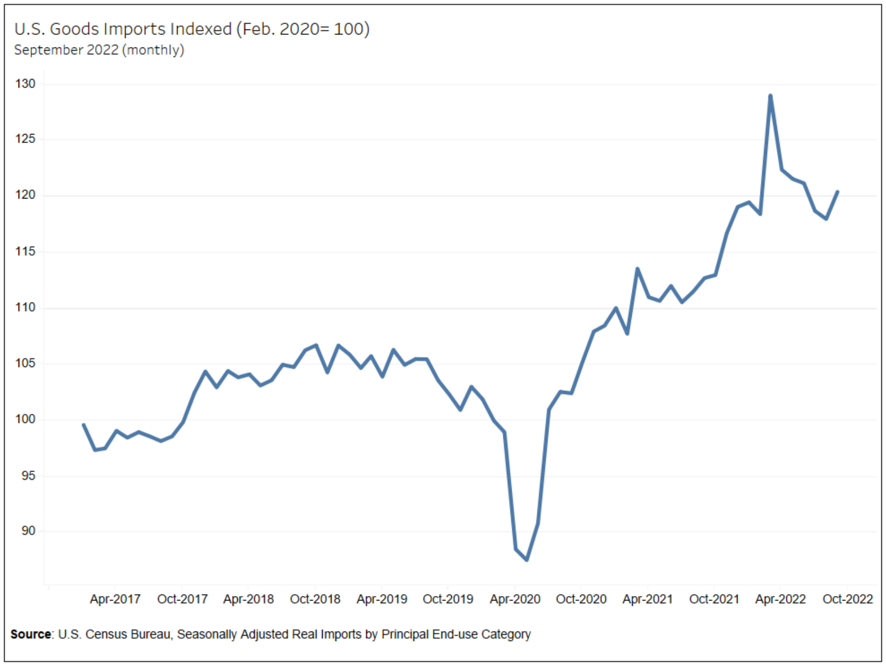

Figure 5-5. Index of US Imported Goods

Control equipment vendors have reported quotes from metal fabricators with significant lead times of up to a year for items such as electrical components (e.g., controllers) and valves. Typical lead times previously would have been 18 to 20 weeks. These reports are consistent with the supply chain indicators above on business inventories (such components need to be manufactured, rather than pulled from existing inventory).

Another sign that supply chain bottlenecks may be in the process of being resolved is illustrated by the recent RSM US Supply Chain Index.[124] Figure 5-6 below shows that the index just returned to a positive value for the first time in over two years. This index is a composite of ten subindices, which are shown in Figure 5-7. In particular, the subindices associated with inventory levels from manufacturers to retailers are above historical levels and the other subindices are all improving.

[124] The Real Economy Blog, RSM U.S. Supply Chain Index: Back to normal for first time since pandemic hit, website at https://realeconomy.rsmus.com/rsm-u-s-supply-chain-index-back-to-normal-for-first-time-since-pandemic-hit/.

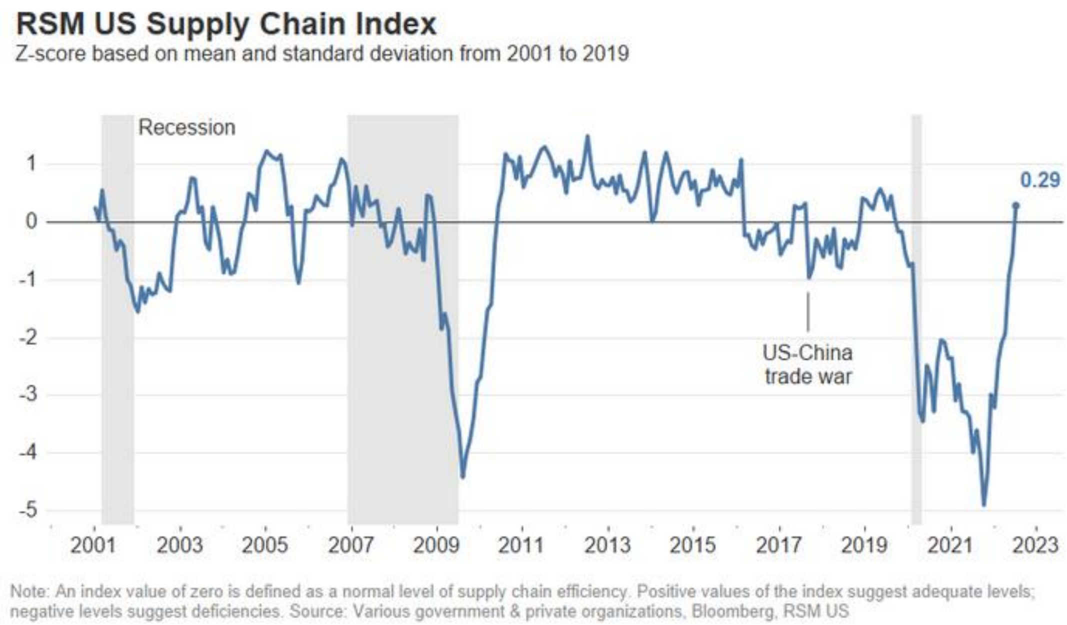

Figure 5-6. RSM US Supply Chain Index

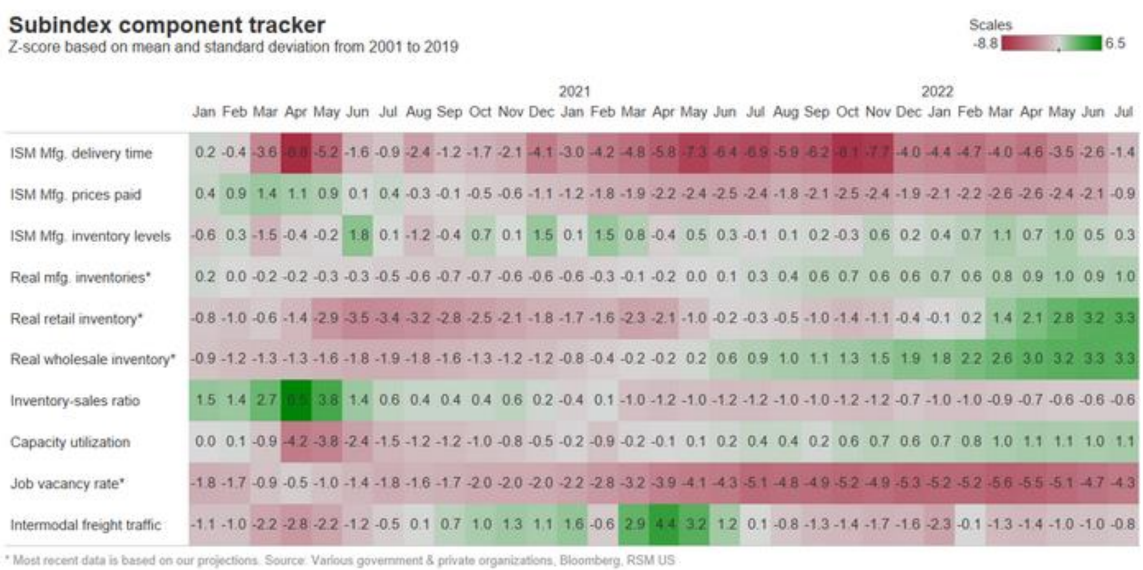

Figure 5-7. RSM US Supply Chain Subindices

Figure 5-8 is a chart of the global supply chain pressure index produced by the Federal Reserve Bank of New York.[125] It also indicates that, at a global level, supply chain linkages are being re-established and

[125] Federal Reserve Bank of New York, Global Supply Chain Pressure Index (GSCPI), website at https://www.newyorkfed.org/research/policy/gscpi#/interactive. The GSCPI integrates several commonly used

pressures reduced. However, supply chain pressure is near historically high levels. While there are good signs both in the US and at the global level for reduced supply chain disruption, it is still too early to know whether the supply chain issues noted by equipment vendors will resolve entirely in the coming years.

Figure 5-8. Global Supply Chain Index

Skilled Labor Constraints for Equipment Design, Fabrication, and Installation
Based on the potential number of NOx control installations for both the non-EGU and EGU sectors, the following non-EGU technologies and applications appear to be competing for limited skilled labor pools:

- SCR applied to ICI boilers;
- SNCR applied to cement kilns and MWCs; and
- Combustion controls applied to natural gas compressor station RICE.

Each of these constraints is addressed within a broader discussion of skilled labor constraints in this section.

SCR on ICI Boilers; and SNCR on Cement Kilns and MWCs. Some control equipment vendors offering SCR might also offer SNCR. These smaller non-EGU NOx sources may experience delays in contracting for equipment design, fabrication, and installation, since vendors may tend to focus on larger and likely more profitable contracts first.[126] For example, MWC units are often smaller than EGUs (usually less than 30 MW of capacity), and some commenters indicated that they would be competing for the same control equipment vendors. As described above in Section 4.5, there is a pool of SCR/SNCR vendors that service the EGU sector, and those vendors may not be inclined to bid on projects at these smaller scales. Those vendors will also likely be servicing the needs of EGUs with existing SCR systems that are optimizing those SCR systems for rule compliance. For both SCR and SNCR systems for these groups of affected non-EGU sources, it appears that a different set of equipment vendors would be serving them

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metrics with the aim of providing a comprehensive summary of potential supply chain disruptions. Global transportation costs are measured by employing data from the Baltic Dry Index (BDI) and the Harpex index, as well as airfreight cost indices from the U.S. Bureau of Labor Statistics. The GSCPI also uses several supply chain-related components from Purchasing Managers' Index (PMI) surveys, focusing on manufacturing firms across seven interconnected economies: China, the euro area, Japan, South Korea, Taiwan, the United Kingdom, and the United States.

[126] EPA-HQ-OAR-2021-0668-0301. Comment submitted by Minnesota Resource Recovery Association (MRRA).

as compared to the much larger EGU sources (at least from a design perspective). Based on the assessment in Section 4.5, it appears that competition for skilled labor is more likely to be an issue during equipment fabrication and installation phases. For example, large EPC contractors may provide the overall design and engineering of an SCR system but use subcontractors to fabricate and install equipment.

Control Equipment Fabrication Constraints. The comparisons of labor requirements above only include the US boilermaker occupation. Some of the labor needs might be supplied by other workers in aligned industries. These include metal fabrication, machinery, and construction. Local construction labor constraints are addressed below. For metal fabrication and machinery, Figure 5-9 below provides historic data through August 2022 of U.S. capacity utilization in these sectors, along with all manufacturing. As indicated by these data, since 2000, capacity utilization does not tend to peak much above 80%. Current levels of capacity utilization have increased well above their levels following the start of the pandemic. Overall manufacturing capacity stood at 79.6% at the end of August 2022. This compares to the average of 75.3% going back to 2000, and a maximum monthly value of 80.5%. For fabricated metals, the current value of 79.0% compares to a long-term average of 77.6% and a maximum value of 87.8%. For machinery, the current value is 83.5% compared to a long-term average of 75.4% and a maximum of 86.6%.

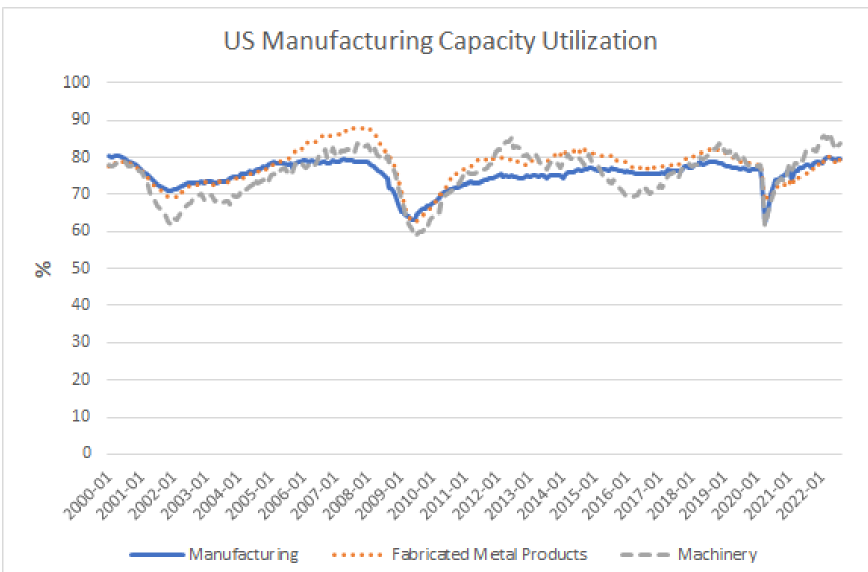

Figure 5-9. US Manufacturing Capacity Utilization[127]

It is important to note that equipment vendors have indicated that they draw support from fabricators throughout North America (including Canada and Mexico). Figure 5-10 presents a chart of Canadian manufacturing capacity that is similar to Figure 5-9 shown above for the U.S. The Canadian data indicate a similar situation as the U.S. for available capacity. The most recent data cover the second quarter of

[127] Board of Governors of the Federal Reserve System, Industrial Production and Capacity Utilization - G.17, website at https://www.federalreserve.gov/releases/g17/current/table1.htm.

2022. Overall manufacturing and fabricated metals capacity are slightly below their long-term averages (back to the year 2000). Machinery capacity is slightly above the long-term average.

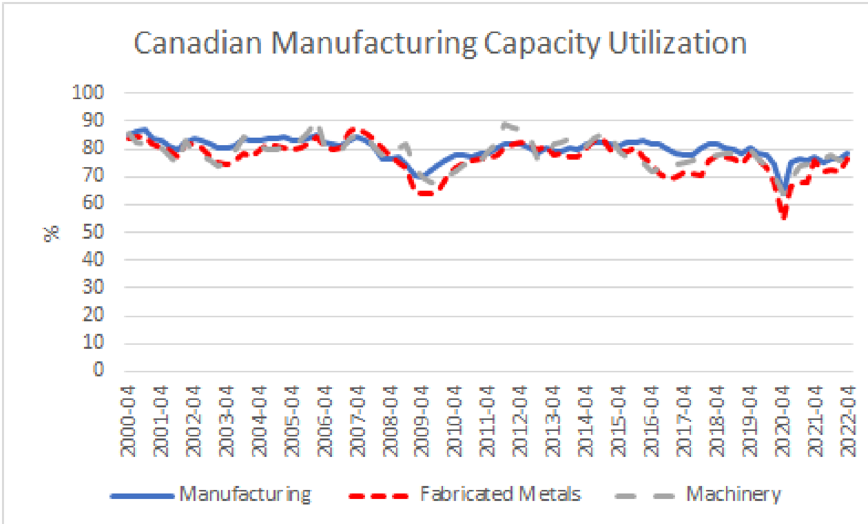

Figure 5-10. Canadian Manufacturing Capacity Utilization[128]

Similar disaggregated capacity utilization data were not identified for Mexico; however, Figure 5-11 provides historical data on the country's manufacturing capacity utilization. The most recent values indicate that capacity is being utilized at levels above historical averages. Taken together with the U.S. and Canadian data above, this information is consistent with reports from some vendors about delays in orders.

[128] Statistics Canada, Industrial capacity utilization rates, by industry, website at https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1610010901.

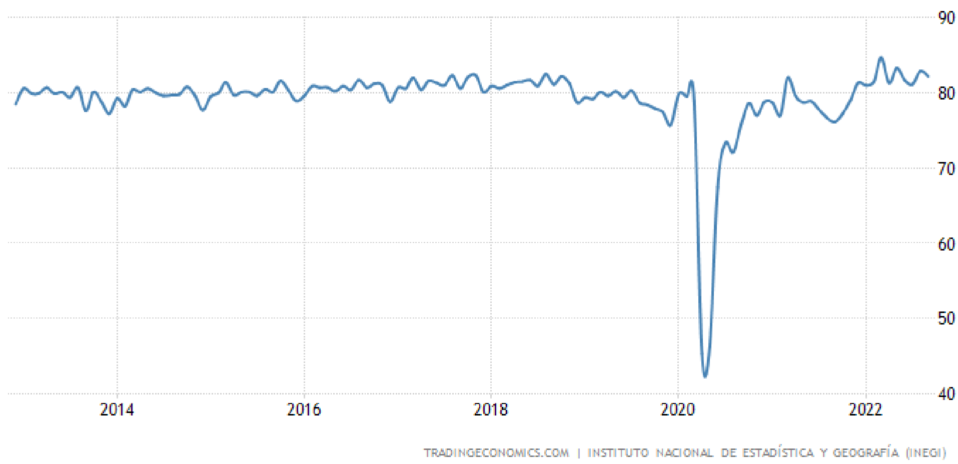

Figure 5-11. Mexican Manufacturing Capacity Utilization[129]

Constraints on Local Construction Labor. Specific to construction labor that could be involved in the installation of large air pollution control systems, such as SCR and SNCR, Figure 5-12 below indicates that nonresidential construction employment in the U.S. has still not recovered to pre-pandemic levels (still 3% below levels in February 2020).[130] A regional assessment of demand and supply of labor is provided in Section 5.2 below.

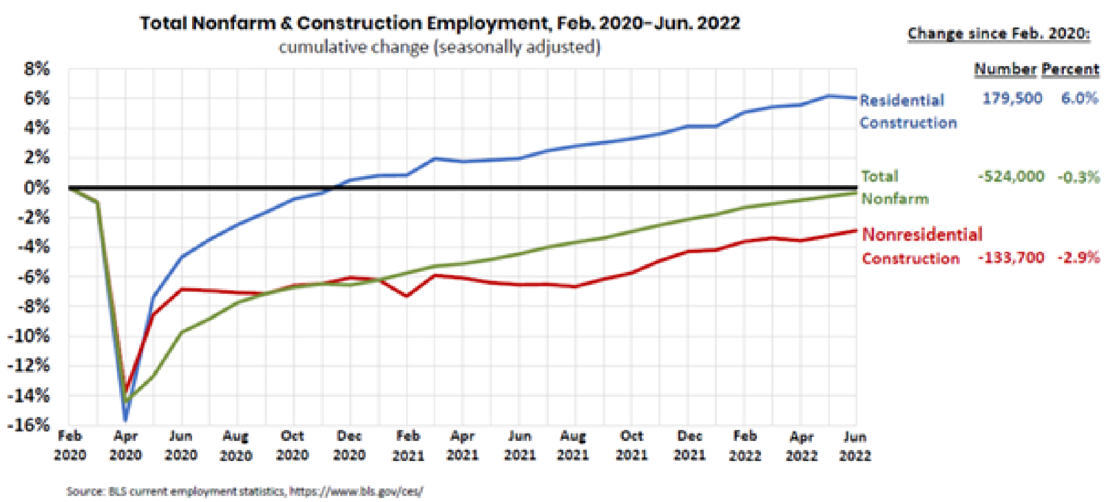

Figure 5-12. US Nonfarm and Construction Employment

[129] Primary source: National Institute of Geography and Statistics, Mexico, https://tradingeconomics.com/mexico/capacity-utilization. These values are for overall manufacturing capacity, rather than just the metal fabrication sector.

[130] Associated General Contractors of America (AGC), "July 2022 Construction Inflation Alert," July 2022.

Skilled labor for Installation of Controls for External Combustion Sources. One example of an analysis of impact to skilled labor necessary to install air pollution control equipment is the analysis EPA conducted in 2005 of boilermaker employment in the US, and its availability to address NOx and SO_2 control installations for the final Clean Air Interstate Rule (CAIR).[131] Note that the Bureau of Labor Statistics (BLS) defines boilermakers as follows:[132]

> *Construct, assemble, maintain, and repair stationary steam boilers and boiler house auxiliaries. Align structures or plate sections to assemble boiler frame tanks or vats, following blueprints. Work involves use of hand and power tools, plumb bobs, levels, wedges, dogs, or turnbuckles. Assist in testing assembled vessels. Direct cleaning of boilers and boiler furnaces. Inspect and repair boiler fittings, such as safety valves, regulators, automatic-control mechanisms, water columns, and auxiliary machines.*

Although the boilermaker labor category closely addresses the skilled labor pool that could be involved in air pollution control installation, we note that a much broader group of trades people are involved in the fabrication and installation of air pollution controls, such as SCR systems. For example, these include contracted metal fabricators that build the housing and ducting of SCR systems, electricians for installing control and monitoring systems, and local construction contractors that build and install the structural components to mount the new SCR system. Many of these skilled trades people would not be included in the BLS estimates of boilermakers. However, extracting employment estimates for all segments of these skilled trades aligned with the air pollution controls industry and related equipment/services is not possible. Thus, using boilermaker employment is a conservative surrogate for the full complement of skilled trades involved.

The key inputs to EPA's 2005 boilermaker labor analysis were:

- Boilermaker population: 28,000
- Percentage of boilermaker labor available for CAIR retrofits: 35%
- Number of annual hours worked by a boilermaker: 2,000 hours/year
- SCR duty rate: 0.175 year/MW (annual boilermaker labor per unit of EGU capacity)

Recent BLS employment estimates for boilermakers (May 2021) indicate a significant contraction for the occupation to 12,920.[133] EPA noted in 2005 that BLS was forecasting lower boilermaker employment due to both lower demand and an accelerated retirement rate among the aging workforce. This employment estimate and the previous labor analysis inputs above provide an annual available boilermaker labor supply estimate of 12,920 x 0.35 x 2,000 hours/yr = 9,044,000 hours/year.

Note the key assumption in the analysis above that 35% of the workforce is still considered available for control retrofits. Given the apparent contraction for the boilermaker occupation, that value may be

[131] EPA, Office of Air and Radiation, "Technical Support Document for the Final Clean Air Interstate Rule, Boilermaker Labor Analysis and Installation Timing," Docket ID No. OAR-2003-0053, March 2005.
[132] U.S. Bureau of Labor Statistics, Occupational Employment and Wages, May 2021 47-2011 Boilermakers, website at https://www.bls.gov/oes/current/oes472011.htm#(1).
[133] U.S. Bureau of Labor Statistics, Occupational Employment and Wages, May 2021 47-2011 Boilermakers, website at https://www.bls.gov/oes/current/oes472011.htm#(1).

overstated.[134] On the other hand, while it is not clear from the 2005 technical memo, the SCR duty rates are likely based on estimates from large coal-fired power plants. Since the affected non-EGU boilers are likely to be smaller, the SCR systems would also be smaller and potentially much less labor intensive to install. For non-EGU sources, EPA estimated 15 SCR systems (excluding compact SCR units for RICE) would be installed on industrial boilers.[135] There are no SCR duty rates available for non-EGUs as there are for EGUs. For a rough gauge of the fabrication and installation labor requirement for SCRs for non-EGUs, the following assumptions were made:[136]

- SCR is being retrofitted to a 250 MMBtu industrial oil/gas boiler;
- EPC vendor percentage of total project cost is 20% (design, procurement, and construction management);
- Fabrication and installation labor percentage of total project cost is 40%; and
- The loaded average fabrication and installation labor rate is $70/hour.

EPA's SCR Cost Manual Spreadsheet[137] was used to generate a total capital cost for the project ($8.63 million in 2022 dollars). This value is assumed to be representative of the average for all non-EGU SCR installations. Application of the assumptions above to the estimated capital cost resulted in a fabrication/installation labor estimate of 39,400 hours. Applying this value to the 15 estimated non-EGU SCR systems (again, excluding compact SCR units for RICE) yields 0.6 million labor hours. Based on the available boilermaker labor estimate above, this load could be absorbed relatively easily. Note this does not account for the boilermaker labor that might be needed for non-EGU SNCR applications and EGU SCR/SNCR optimizations.

Skilled Labor for Combustion Controls on Natural Gas Transmission Compressor RICE. In their comments, TC Energy cited previous EPA rulemaking estimates that only about 75 engines could be retrofit annually on a sustained basis given resource constraints (skilled labor) and the time needed to procure and install equipment. TC Energy referenced a 2014 report by INGAA, t which is the source of the 75 engines per year estimate.138 A number of commenters representing this industry concluded that decades would be needed to address all RICE addressed by the rule. An example cited was the conversion of over 200 natural gas transmission RICE to add Low Emissions Combustion beginning in 1999 as part of the NOx SIP Call. The entire retrofit process took six years according to the commenters.

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[134] Discussions with SCR vendors indicate that metal fabricators are currently constrained across North America (includes, US, Canadian and Mexican suppliers).

[135] U.S. EPA. Technical Memorandum. Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs. March 15, 2023.

[136] These assumptions are based on discussions with control equipment vendors, BLS labor statistics (U.S. Bureau of Labor Statistics, Occupational Employment and Wages, May 2021 47-2011 Boilermakers, website at https://www.bls.gov/oes/current/oes472011.htm#(2)), and industry wage/benefits information (Boilermakers Union Local 242, Wages & Benefits, website at https://boilermakers242.com/wages-benefits/).

[137] EPA, Cost Reports and Guidance for Air Pollution Regulations, website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[138] Interstate Natural Gas Association of America (INGAA), "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Prime Movers Used in the Interstate Natural Gas Transmission Industry," prepared by Innovative Environmental Solutions and Optimized Technical Solutions, INGAA Foundation Final Report No. 2014.03, July 2014.

Multiple commenters referenced INGAA's estimated limit of 75 RICE retrofits per year based on the size of the skilled labor pool for such retrofits.[139] Although state-level data were not provided in these comments, INGAA estimated that most control retrofits would be directed at 2,050 two-stroke engines (this includes engines in 40 states and was thought to be ~80% complete at the time). INGAA pointed out that the 75 retrofits/year estimate compared to 50 retrofits/year carried out earlier during the NOx SIP Call.

The estimate of 75 retrofits per year provided by INGAA is now about 10 years old. INGAA also noted in its report that this estimate was based on current resource availability and did not take account of hiring and training to respond to a new regulations. A skilled labor pool has likely already grown given the extent of retrofits over the previous years to service the growing size of the current storage and transmission industry. In addition, there has been a significant expansion in RICE used for other applications, including backup power for data centers. Therefore, the skilled labor pool for engine retrofits should have grown with the size of the RICE population. Considering just the growth in natural gas production, which in the US has nearly doubled since 2005 (as indicated in the Figure 5-13 below), a skilled labor pool should be present to support the retrofits in the industry. Assuming that the size of the skilled labor pool has grown along with natural gas production and RICE-use expansion and would continue to grow in response to a regulatory mandate as INGAA acknowledged in their report, this would allow for a reasonable estimate that the size of the labor pool with the requisite skills could be doubled from the prior estimate and thus would be large enough to conduct 150 specialized retrofit installations per year (75 retrofits/yr x 2). Using EPA's estimate of 905 affected engines for the final rule as a very conservative upper-bound estimate for the number of units that may require such specialized labor, the maximum amount of time to apply the retrofit controls to this estimated number of engines would be just over 6 years (a lower upper-bound figure of 717 engines would reduce the time estimate accordingly).

[139] Interstate Natural Gas Association of America (INGAA), "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Prime Movers Used in the Interstate Natural Gas Transmission Industry," prepared by Innovative Environmental Solutions and Optimized Technical Solutions, INGAA Foundation Final Report No. 2014.03, July 2014.

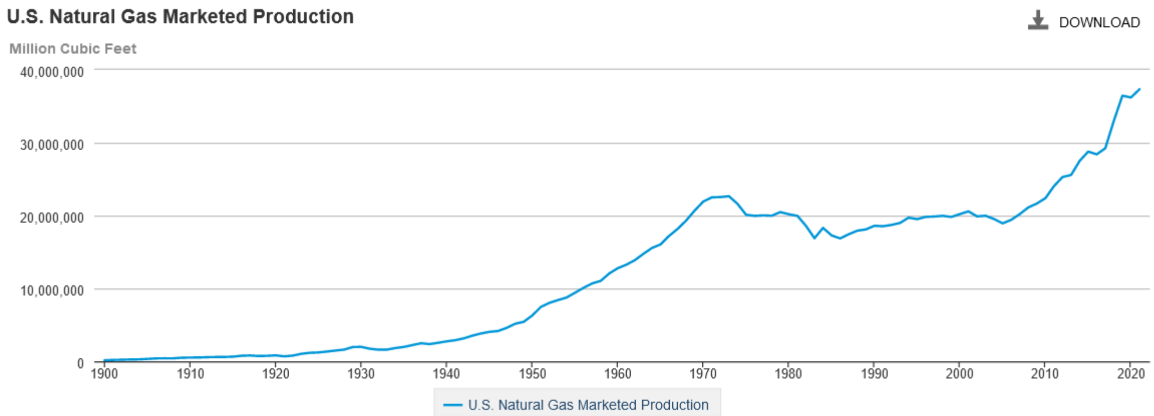

Figure 5-13. Historic US Natural Gas Production[140]

From a skilled labor perspective, industry commenters seemed to be most concerned about the population of RICE engines that were very old (>50 years). The concern is that there is a limited skilled labor pool that has the experience working with RICE of that vintage. In situations where the control is LC, rather than an add-on control, skilled mechanics would be needed. The data supplied to EPA on affected RICE and that are estimated to adopt LC does not include the age of the equipment.

5.2 Regional Analysis of Demand and Available Supply of Labor

For the purposes of examining regional labor constraints, to the extent they may exist, the metrics of most interest are those that address state-level construction labor that could be involved in the local installation of NOx controls, in particular, larger SCR and SNCR systems. Design and equipment fabrication could occur locally, however, in most cases, these services might come from suppliers outside of the region.

Figures 5-14 through 5-17 provide state-level summaries of employment within the Specialty Trade Contractors category from 2005 through October of 2022.[141] The state-level summaries provided represent the states with the greatest number of estimated non-EGU controls installations. BLS defines the Specialty Trade Contractors subsector as comprising establishments whose primary activity is performing specific activities (e.g., pouring concrete, site preparation, plumbing, painting, and electrical work) involved in building construction or other activities that are similar for all types of construction, but that are not responsible for the entire project. The work performed may include new work, additions, alterations, maintenance, and repairs. The production work performed by establishments in this subsector is usually subcontracted from establishments of the general contractor type or operative builders, but especially in remodeling and repair construction, work also may be done directly for the owner of the property. Specialty trade contractors usually perform most of their work at the construction site, although they may have shops where they perform prefabrication and other work.

[140] U.S. Energy Information Administration (EIA), Natural Gas, website at https://www.eia.gov/dnav/ng/hist/n9050us2a.htm.
[141] U.S. Bureau of Labor Statistics and Federal Reserve Bank of St. Louis, All Employees: Construction: Specialty Trade Contractors in Texas [SMU48000002023800001SA], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/SMU48000002023800001SA, December 6, 2022.

Establishments primarily engaged in preparing sites for new construction are also included in this subsector.[142]

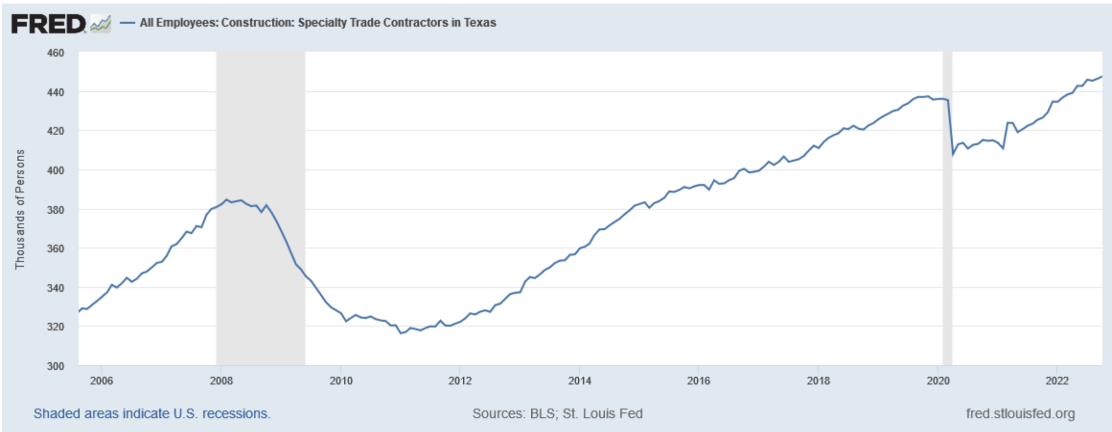

Figure 5-14. Specialty Trade Contractors in Texas

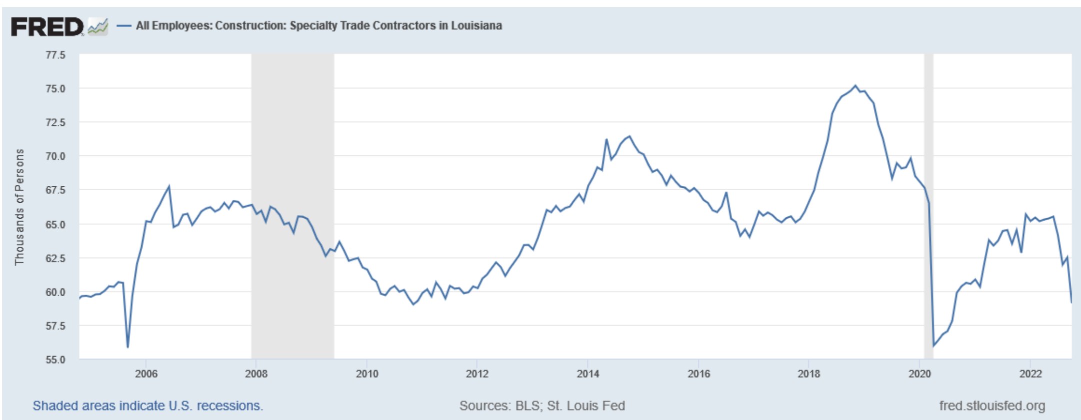

Figure 5-15. Specialty Trade Contractors in Louisiana

[142] U.S. Bureau of Labor Statistics, Specialty Trade Contractors: NAICS 238, website at: https://www.bls.gov/iag/tgs/iag238.htm.

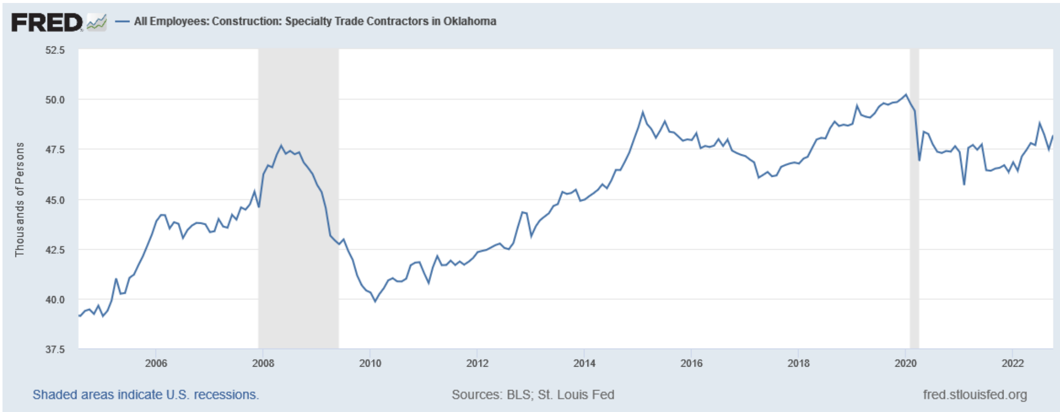

Figure 5-16. Specialty Trade Contractors in Oklahoma

Figure 5-17. Specialty Trade Contractors in Ohio

As indicated by these summaries, employment has rebounded to above pre-pandemic levels in Texas and Ohio. Louisiana's employment level is still well below 2019 levels, initially slowing through 2021, but with sharp declines in the number of employees again in 2022. This information doesn't necessarily provide a sense of available labor capacity going forward; however, it does indicate that some states have lost installation labor capacity as compared to historic levels, though it could also indicate that the overall installation labor market could potentially be higher than current levels.

A forward-looking indicator of construction activity is the Construction Backlog Indicator (CBI) from Associated Builders and Contractors (ABC).[143] A chart showing the latest (September 2022) CBI reading is shown in Figure 5-18 below. According to ABC, the CBI is a forward-looking national economic indicator that reflects the amount of work that will be performed by commercial and industrial contractors in the months ahead. We include data from this indicator in this report because this new, national economic data set is the only reliable leading economic indicator offering this level of specificity focused on the

[143] CBI methodology: https://www.abc.org/Portals/1/Documents/CBI/CBIMethodology1.pdf. September release: https://www.abc.org/News-Media/News-Releases/entryid/19644/abcs-construction-backlog-indicator-jumps-in-september-contractor-confidence-remains-steady.

U.S. commercial and institutional, industrial, and infrastructure construction industries, which are among those affected by this final rule.

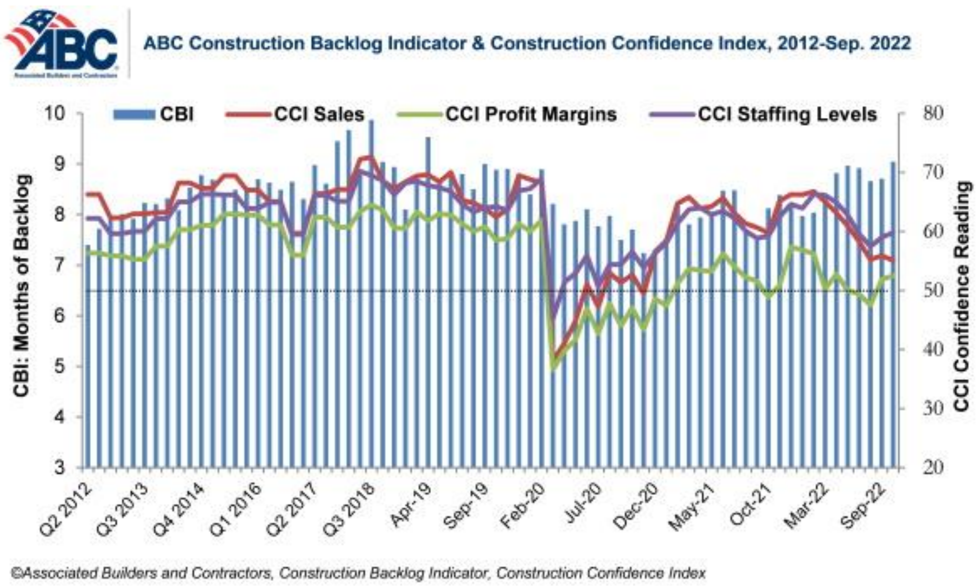

Figure 5-18. Construction Backlog Indicator through September 2022

The CBI measures months of backlog in construction activity. The September 2022 value of 9.0 is an increase above the value of 8.7 measured in August 2022. It is also 1.4 points higher than the value from September 2021. Figure 5-18 also provides ABC's Construction Confidence Index, which has three separate readings representing sales, profit margins, and staffing. Any value above 50 indicates expectations for growth over the next six months. So, while values are down from a year ago, the readings all continue to point toward higher levels of construction activity.

6. Summary of Results

6.1 Estimated Time Needed for Controls to be Installed on All Non-EGU Emissions Units

Assuming that all phases of permitting and control installation proceed without delays and not accounting for any supply chain constraints noted in Section 6.3 below, when looked at individually, the estimated non-EGU emissions units could potentially install controls to achieve compliance within 28 months of final rule publication (see Table 4-1).

If there are supply chain disruptions or delays (including vendor or equipment shortages, such that vendor capacity does not increase from its current level in order to meet demands for additional control installations), this 28-month time estimate could increase in some cases. As described in more detail in Section 6.3 and summarized in Table 6-1 below, the total amount of time required including potential supply chain delays is as follows for the source types affected by potential delays:

- ASNCR application extends to 35 - 57 months (MWC),
- LC application to natural gas transmission system RICE extends to 40 – 72 months,
- Boilers extends to as much as 37 months, and
- Cement extends to as much as 58 months.

See Section 6.3 for additional details.

6.2 Estimated Time Needed for Non-EGU Emissions Units to Install Controls

After factoring in all information reviewed for this report, Table 6-1 below provides a summary of the number of months estimated to conduct all phases of control installation. Two timelines are provided in the last two columns of the table.

Table 6-1. Summary of Expected Calendar Time Required for Control Installation for an Individual Source

Industry	Emissions Source Group	Control Technology	Total Estimated Installs	Estimated Install Timeline (months)	SCD Install Timeline (months)
Cement and Concrete Product Manufacturing	Kilns	SNCR	16	17 - 24	35 - 58
Glass and Glass Product Manufacturing[a]	Melting Furnaces	LNB	61	9 – 15	9 – 15
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	19	9 – 15	9 – 15
Pipeline Transportation of Natural Gas[b]	RICE 2-Cycle	Layered Combustion	394	6 – 12	40 – 72

Industry	Emissions Source Group	Control Technology	Total Estimated Installs	Estimated Install Timeline (months)	SCD Install Timeline (months)
Pipeline Transportation of Natural Gas[b]	RICE 4-Cycle Rich Burn	NSCR	30	6 – 12	6 – 12
Pipeline Transportation of Natural Gas[b]	RICE unspecified	NSCR or Layered Combustion	323	6 – 12	40 – 72
Pipeline Transportation of Natural Gas[b]	RICE 4-Cycle Lean Burn reciprocating	SCR	158	10 – 19	10 – 19
Affected Non-EGU Industries[c]	Boilers	LNB + FGR	151	9 – 15	9 – 15
Affected Non-EGU Industries[c]	Boilers	SCR	15	14 – 25	26 – 37
Municipal Waste Management	MWC Boilers	LN^{tm} + SNCR	4	22 – 28	22 – 28
Municipal Waste Management	MWC Boilers	ASNCR	57	17 – 23	35 - 57

The general approach for assessing time requirements is summarized below:

Step 1 – Estimate base time required for equipment design, vendor selection, fabrication, and installation ("estimated installation timeline").

- These estimates were taken from comments received, previous EPA reports supporting the rule, and related technical reports (e.g., RACT assessments). Typically, these estimates are based on a range of months provided in a data source or combination of data sources. These timelines are further detailed in Section 4 (summarized in Table 4-1).

Step 2 – Estimate the additional amount of time associated with supply chain delays.

- These are addressed on a case-by-case basis in Section 6.3.

We note that these estimates presume that the current (i.e., 2022) state of supply chain delays, including those associated with current levels of skilled labor and availability of necessary materials and resources, are assumed to continue through 2026, though there is strong evidence of easing of supply chain delays discussed in Section 5.

6.3 Potential Impact of Supply Chain Constraints on Control Installation Timing

For key NOx source and control combinations, supply chain issues could increase the estimated install timeline. Supply chain concerns include: equipment vendor availability (e.g., EPCs that handle overall engineering/design, fabrication, and installation); equipment fabrication backlogs; skilled labor constraints; local installation labor constraints; and limitations on raw materials. The potential for these issues to delay equipment installation may be important considerations to support the need to include flexibility provisions for affected units to comply with the rule.

Descriptions of where supply chain delays are expected, as well as their length, are provided below:

- No expected supply chain delays: for control installations in Table 6-1, where the "SCD timeline" is the same as the "estimated install timeline", the control technology is expected to be readily available or to have a short lead time for design and fabrication (e.g., compact SCR[144] or NSCR applied to RICE; LNB for furnaces in the glass and glass product manufacturing and reheat furnaces in iron and steel). Further, skilled labor for control equipment design and installation is expected to be available to meet the estimated demand for services.
- Supply chain delay potential: additional time will likely be needed due to an identified supply chain limitation. Situations where supply chain delays are expected are summarized below along with an estimate of the length of delay:

    - <u>Cement and concrete product manufacturing, kilns installing SNCR for compliance:</u> estimated units (16) may be competing for SNCR EPCs along with MWCs (61). Although 36 EGU SNCR optimization projects are expected, as stated previously, in-house personnel should be able to accommodate these projects. The pool of identified US SNCR vendors is 9, but the number of these vendors that actually conduct the design (including modeling), engineering, fabrication, and installation may be less than this. Based on discussions with control equipment vendors, 5 SNCR installation projects per year is a representative annual capacity for each vendor.

    - <u>MWC boilers</u>: these 61 sources are estimated to achieve compliance by applying either LN^{tm} + SNCR or ASNCR. The pool of SNCR EPC contractors will likely be limited to those with boiler expertise in the MWC sector. For the four installations of LN^{tm} + SNCR, these all involve a single OEM for the original MWC unit (Covanta using their own proprietary technology). Given the lack of competition for these facilities and no other supply chain delays, it is assumed that Covanta can address these installations within the required installation timeline.

      The 57 expected ASCNR and 16 cement kiln SNCR installations may be competing for the same set of vendors. On-line information suggests that there are 3 to 5 vendors capable of supplying ASNCR technology. The total number of EPC contractors for SNCR is somewhat larger, but, if selected, it is possible that those companies would still subcontract to the more limited pool of experienced ASNCR equipment suppliers and installers to complete a total of 73 SNCR or ASCNR installations.

      Assuming that initial studies and permitting requires up to 12 months, there are two years available before the compliance deadline of May 2026 for final design, engineering, fabrication, and installation. Discussions with vendors suggest that full capacity is on the order of 5 projects at any one time for most suppliers (five per year). Therefore, for purposes of this exercise, we assume 15 to 25 installations could be addressed by the assumed vendor pool per year; or 30 to 50 units within 2 years. If vendor capacity does not expand, this leaves an additional 23 to 43 units that may have

[144] Note: compact SCR systems are the same in design as the SCRs applied to RICE in the final rule cost analysis.

difficulty installing controls by May 2026 (which could be some combination of cement kiln SNCR or MWC ASNCR installations). With the current vendor pool able to address 15 to 25 units per year, approximately an additional 18 to 34 months (that is, 23 units/15 units/year x 12 months/year to 43 units/15 units/year x 12 months/year) may be needed to address installations at all affected units. This results in a total maximum supply chain delay timeline of 35 to 58 months (17 to 24 months + 18 to 34 months) for cement installations of SNCR and 35 to 57 months (17 to 23 months + 18 to 34 months, again showing the broadest range of values) for ASNCR installation at MWCs.

- Pipeline transportation of natural gas, RICE: Application of layered combustion controls to some RICE may involve emissions units that are over 60 years old. We note that the age of RICE that may install controls in response to this final rule is not available in the emissions inventory. Comments received by EPA indicate that while retrofit kits should be available for these RICE, installations on older units may require skilled labor familiar with these units and the specialized control kits to be applied. A key uncertainty is the number of RICE that will elect to apply these combustion kits versus NSCR or another compliance option (e.g., engine replacement or electrification). EPA's estimates in Table 6-1 above indicate that 394 RICE are estimated to apply layered combustion and 323 RICE are estimated to apply either layered combustion or NSCR. Based on these estimates and on the conservative assumption that all of these engines are approximately 60 years in age, this results in a likely high upper range estimate of 717 units that could require specialized labor to install controls (technicians with the skills to apply layered combustion control kits to older RICE). Industry comments, which we were not able to verify, cited an older report suggesting that a skilled labor pool is available to address at most 75 RICE per year. However, other estimates based on projections of available skilled labor for such RICE as reflected in Figure 5-13 that are more recent than the labor pool provided in the industry report show the potential for a RICE retrofit rate as high as 150 RICE per year. With 905 RICE potentially installing NOx controls according to the final rule non-EGU cost analysis, a retrofit rate of 150 per year would yield an absolute upper bound of 905/150 = 6 year (or 72 month) installation timeframe for this number of potential RICE retrofits. Hence, depending on the number of older RICE that industry decides to control with layered combustion, potentially the full amount of time needed to complete installations of layered combustion on all affected units is 717/150 = 4.8 years (58 months). For the portion of RICE estimated to be addressed by either layered combustion or NSCR, if half of the RICE are addressed by layered combustion or NSCR, this results in a total estimate of 506 units. The total amount of time required to address them by the available skilled labor pool is then 506/150 = 3.4 years (40 months). The estimated supply chain delay timeline if all 905 RICE install controls in response to this final rule is expected to range from 40 to 72 months. These estimates do not account for the potential for replacement of older RICE with new engines instead of retrofitting or further growth in the labor pool and other resources.

- Affected industries, boilers: sources that require installation of SCR for compliance aren't expected to compete for control equipment vendors that serve the EGU sector for equipment fabrication and installation, since EPA expects primarily optimization of SCRs at existing EGUs which do not require a vendor plus a relatively small number of SCR installations by May 2026. Also, EGU SCR EPCs are generally a different group of vendors than those that serve the non-EGU sector. The number of SCR installations estimated isn't exceptionally large as indicated in Table 6-1; however, information gathered from vendor contacts indicates some potential delays for equipment fabrication and certain imported components. Considering this potential additional 12 months of supply chain delay related to equipment fabrication, the full amount of time needed for SCR installation at an affected industry boiler could extend to 26 to 37 months (as noted in the SCD timeline in Table 6-1).

Appendix A. North American SCR and SNCR Suppliers

This listing of SCR/SNCR vendors serving the North American market was developed from the on-line data sources cited below. Based on information presented on their corporate websites, each SCR supplier was allocated into one of the following market segments as shown in Table A-1:

- EGU and Large Non-EGUs: most of these vendors serve the EGU market; but a small number also serve large non-EGU sources (e.g., MWCs);
- Small EGUs and Non-EGUs: these vendors serve small EGUs, such as natural gas turbine power plants and the non-EGU sector;
- Internal Combustion Engines: these vendors supply compact SCR systems, primarily for implementation on RICE.

Table A-2 provides a listing of SCR catalyst manufacturers or recyclers. Table A-3 provides a listing of SNCR vendors.

Data Sources:

- AWMA Vendor Listings: https://awmabuyersguide.com/;
- Air Pollution Equipment.com: https://www.airpollutioncontrolequipment.com/more-air-pollution-control-equipment-manufacturers-listings/;
- Institute of Clean Air Companies: https://www.icac.com/page/Members;
- General internet search.

Table A-1. SCR Vendors

Company	Apparent Market Segment	Website
1. Babcock Power Inc.	EGU/large Non-EGU	www.babcockpower.com
2. Babcock & Wilcox	EGU/large Non-EGU	https://www.babcock.com/home/products/selective-catalytic-reduction-scr-systems/
3. BHI-FW	EGU/large Non-EGU	http://www.bhifw.com/eng/technologies/scr.html
4. Braden	EGU/large Non-EGU	https://braden.com/environmental-care-solutions/
5. CECO/Peerless	EGU/large Non-EGU	https://www.cecoenviro.com/products/selective-catalytic-reduction-scr-peerless-emissions/
6. CEECO Equipment	EGU/large Non-EGU	https://www.ceecoequipment.com/page/engineered-equipment-solutions
7. General Electric	EGU/large Non-EGU	https://www.ge.com/steam-power/services/aqcs/upgrades/nox
8. Fuel Tech Inc.	EGU/large Non-EGU	https://www.ftek.com/en-US/products/productssubapc/scr-systems-industrial
9. Mitsubishi Power Systems Americas, Inc.	EGU/large Non-EGU	https://power.mhi.com/products/aqcs/lineup/flue-gas-denitration
10. CTP Sinto America	Small EGU/Non-EGU	https://ctp-airpollutioncontrol.com/solutions/systems
11. Branch Environmental	Small EGU/Non-EGU	https://www.branchenv.com/selective-catalytic-reduction-scr/
12. Catalytic Products International	Small EGU/Non-EGU	https://www.cpilink.com/selective-catalytic-reduction
13. CORMETECH	Small EGU/Non-EGU	https://www.cormetech.com/screngineering-design/

Company	Apparent Market Segment	Website
14. Durr Systems	Small EGU/Non-EGU	https://www.durr.com/en/products/environmental-technology/exhaust-gas-and-air-pollution-control
15. GEA	Small EGU/Non-EGU	https://www.gea.com/en/products/emission-control/catalytic-gas-cleaning/index.jsp
16. Hamon	Small EGU/Non-EGU	https://www.hamon.com/power/
17. Jardar Systems	Small EGU/Non-EGU	https://www.jardarsystems.com/pollution-control-systems.html
18. McGill AirCLEAN LLC	Small EGU/Non-EGU	https://www.mcgillairclean.com/proddenox
19. Nationwide Boiler	Small EGU/Non-EGU	https://www.nationwideboiler.com/environmental-solutions.html
20. SVI Industrial	Small EGU/Non-EGU	https://sviindustrial.com/selective-catalytic-reduction-systems/
21. Turner EnviroLogic	Small EGU/Non-EGU	https://www.tenviro.com/Systems/Selective-Catalytic-Reduction-Systems-SCRs
22. Catalytic Combustion	RICE: compact SCR	https://www.catalyticcombustion.com/products/selective-catalytic-reduction/
23. DCL International	RICE: compact SCR	https://dcl-inc.com/products/scr-systems/
24. HUG Engineering	RICE: compact SCR and Small EGU/Non-EGU	https://hug-engineering.com/technologies/low-emissions/technology
25. Johnson-Matthey	RICE: compact SCR	https://matthey.com/products-and-markets/other-markets/stationary-emissions-control/scr-systems
26. Miratech	RICE: compact SCR	https://www.miratechcorp.com/our-products/scr-dpf-solutions/
27. MSHS	RICE: compact SCR and Small EGU/Non-EGU	https://www.mshs.com/emissions-aftermarket-treatments/selective-catalyst-reduction-scr-systems/;
28. NETT Technologies	RICE: compact SCR	https://www.nettinc.com/power-generator-scr-systems

Table A-2. SCR Catalyst Manufacturers or Recyclers

Company	Website
1. CDTi	https://cdti.com/engine-emissions-2022/
2. CORMETECH	https://www.cormetech.com/
3. Mitsubishi Power Systems Americas, Inc.	https://power.mhi.com/products/aqcs/lineup/flue-gas-denitration
4. Umicore	https://fcs.umicore.com/en/stationary-catalysts/
5. Environex	https://environex.com/services/industrial-catalyst/catalyst-replacement/

Table A-3. SNCR Vendors

Company	Website
1. Babcock Power Inc.	www.babcockpower.com
2. Babcock & Wilcox	https://www.babcock.com/home/products/selective-catalytic-reduction-scr-systems/
3. CECO Environmental	https://www.cecoenviro.com/products/selective-non-catalytic-reduction-sncr/
4. CORMETECH	https://www.cormetech.com/sncrengineering-design/
5. CTP Sinto America	https://ctp-airpollutioncontrol.com/solutions/systems
6. Durr Systems	https://www.durr.com/en/products/environmental-technology/exhaust-gas-and-air-pollution-control
7. Fuel Tech, Inc. (mentions also supplying ASNCR)	www.ftek.com; https://www.ftek.com/en-US/products/productssubapc/urea-sncr;
8. ISGEC (mentions also supplying ASNCR)	https://www.isgec.com/apce/ba-apce-DeNox.php
9. Mobotec (mentions also supplying ASNCR)	https://www.environmental-expert.com/products/rotamix-model-sncr-advanced-selective-non-catalytic-reduction-system-438786

Comments of the Interstate Natural Gas Association of America on the U.S. Environmental Protection Agency's Proposed Rule: "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard"

87 Fed. Reg. 20,036 (April 6, 2022)

Docket ID No. EPA–HQ–OAR–2021–0668

Interstate Natural Gas Association of America

Date: June 21, 2022

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Executive Summary

The Interstate Natural Gas Association of America ("INGAA"), a trade association that represents 26 members of the interstate natural gas pipeline industry, is pleased to submit comments on the United States Environmental Protection Agency's ("EPA" or the "Agency") proposed "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" ("Proposed Rule"). The Proposed Rule represents significant efforts on the part of the Agency to address interstate transport of nitrogen oxides ("NOx") and the "significant contribution" of upwind states to downwind nonattainment and maintenance issues. INGAA has substantial experience addressing these issues and a track record of working with EPA to develop feasible and environmentally meaningful rules to address air quality.

The Proposed Rule is based on underlying assumptions and takes approaches to regulation that INGAA believes EPA should reevaluate. Most significantly, the Proposed Rule reflects a considerable underestimation of the number of units serving the pipeline transportation of natural gas industry that would become subject to new proposed emission limits. INGAA's estimates of these units are nearly five times larger than EPA's assumptions. The emission reductions that would result such a miscalculation would overwhelm EPA's intent as expressed in the Proposed Rule. Those projections, however, are what EPA has determined are needed to address the "significant contribution," as defined by the Clean Air Act, of the pipeline transportation of natural gas industry to downwind air quality problems. For that reason, the Proposed Rule would result in over-control in violation of Supreme Court and D.C. Circuit precedent. EPA can address this over-control problem by withdrawing the Proposed Rule and issuing a new proposal that achieves the emission reductions EPA has concluded are appropriate.

EPA could achieve that outcome, for instance, by reevaluating the horsepower threshold and potentially raising it to reflect the realities industry faces. INGAA looks forward to supporting EPA's efforts in this regard.

In addition, EPA should incorporate emissions averaging as a compliance flexibility. Averaging will help to ensure that states and sources achieve the overall environmental objectives of the Proposed Rule while offering a level of flexibility that will make compliance more efficient and effective overall. EPA itself, with INGAA's input, developed emissions averaging rules in previous rulemakings and has approved the use of NOx emissions averaging in state plans for the natural gas industry. Incorporating averaging here would help ensure the successful implementation of a new rule.

EPA should also better account for realities facing the industry with respect to the time needed to complete the retrofits this new regulatory initiative envisions. There are considerable constraints on expertise and materials that will be needed to complete the installation of controls to meet the Proposed Rule's emission limits. These constraints render the proposed 2026 compliance timeframe unworkable. INGAA requests that EPA consider a phased approach to compliance that can be tailored to ensure the most timely implementation possible.

For similar reasons, the Proposed Rule would have serious impacts on reliability. EPA has not assessed how the natural gas pipeline system will be impacted or offered any guidance on how the massive effort to retrofit affected units could be coordinated to avoid reliability impacts. EPA must address reliability to provide an adequate basis for a new rule.

The Proposed Rule also includes a number of technical assumptions and requirements related to achieving and assuring compliance with the emission limits it would impose. INGAA believes that a number of changes to these provisions is warranted, but also supports many of the provisions EPA has developed. For instance, although INGAA does not disagree with the emission limits EPA has proposed for the Proposed Rule's affected units, INGAA does believe that four stroke lean burn engines are not likely to comply with the proposed emission limits through installation and operation of selective catalytic reduction controls and are instead much more likely to use low emission combustion technology. A new rule should address that and similar issues.

INGAA also supports EPA's proposal to rely on parameter monitoring for compliance assurance and not to require continuous emission monitoring systems. On the other hand, INGAA does not believe EPA's proposed requirements that sources conduct semi-annual performance tests and semi-annual reporting are necessary to ensure compliance with the Proposed Rule, and they may be practically impossible for certain units.

Finally, INGAA has identified apparent errors or areas for clarification in the Proposed Rule's regulatory language and suggests revisions in these comments. INGAA further notes that substantial changes or departure from the proposal, including the addition of new states or new sources to the rule's coverage, would require a new proposed action.

INGAA supports appropriate action to address upwind state contributions to downwind nonattainment and maintenance issues for the 2015 ozone NAAQS. The Proposed Rule, however, is unfortunately premised on significantly flawed information that will undoubtedly lead to ongoing legal disputes and implementation problems. For those reasons, the proposal should be withdrawn, and EPA should issue a new proposal that remedies over-control. INGAA offers its expertise to assist in those efforts and appreciates the opportunity to continue working with EPA.

Interstate Natural Gas Association of America

Comments of the Interstate Natural Gas Association of America on the U.S. Environmental Protection Agency's Proposed Rule:

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

87 Fed. Reg. 20,036 (April 6, 2022)

Docket ID No. EPA-HQ-OAR-2021-0668

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I. Introduction

The Interstate Natural Gas Association of America ("INGAA"), a trade association that represents 26 members of the interstate natural gas pipeline industry, respectfully submits these comments in response to the United States Environmental Protection Agency's ("EPA" or the "Agency") proposed rule entitled "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" (hereinafter, "Proposed Rule"), which was published in the Federal Register on April 6, 2022.[1]

INGAA members own and operate a large percentage of the reciprocating internal combustion engines ("RICE" or "engines") used in the interstate transportation of pipeline natural gas.[2] INGAA member companies transport more than 95 percent of the nation's natural

[1] 87 Fed. Reg. 20,036 (Apr. 6, 2022).

[2] The Proposed Rule does not appear to limit its application to interstate transportation of natural gas. INGAA's representation of its members, however, only extends to interstate pipelines. Although many of the issues addressed

gas, through approximately 200,000 miles of interstate natural gas pipelines. In 46 of the 48 contiguous United States, INGAA member companies operate over 5,400 natural gas compressors at over 1,300 compressor stations and storage facilities along the pipelines to transport natural gas to local gas distribution companies, industrial manufacturers, gas marketers, and gas-fired electric generators. This includes over 3,500 stationary natural gas-fired reciprocating engines. Accordingly, this rulemaking is of tremendous importance to INGAA and its members.

EPA first established primary and secondary national ambient air quality standards ("NAAQS") to protect against the adverse effects of nitrogen oxides ("NOx") and ozone in 1971 and has revised the standards numerous times since then.[3] EPA completed the most recent review of the primary and secondary NOx standards in 2018 and 2012, respectively, where the Agency retained the pre-existing NAAQS. NOx emissions, as a precursor to the formation of ozone, are subject to significant regulation under EPA's ozone NAAQS program. EPA last revised the ozone standards in 2015, setting the primary and secondary ozone NAAQS at 70 parts per billion ("ppb") in the form of the annual fourth-highest daily maximum 8-hour average concentration, averaged over 3 years.[4]

In addition to addressing emissions from sources located within NOx and ozone nonattainment areas, EPA has a long-established approach to reducing NOx emissions from sources located in "upwind" states that "significantly contribute" to either nonattainment or interference with maintenance in "downwind" states. EPA's authority to address the interstate

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in these comments may apply with equal force to intrastate pipelines and natural gas transportation, INGAA does not purport to speak for that segment of the industry.

[3] Primary standards are intended to protect the public health, and secondary standards are intended to protect the public welfare.

[4] 80 Fed. Reg. 65,292 (Oct. 26, 2015).

transport of NOx emissions is found in the good neighbor provision of the Clean Air Act ("CAA" or the "Act").[5] That provision requires each state to submit a State Implementation Plan ("SIP") that prohibits emissions that will significantly contribute to nonattainment of a NAAQS, or interfere with maintenance of a NAAQS, in a downwind state. If a state fails to submit a good neighbor SIP or if EPA disapproves such a SIP, the Agency may be authorized to promulgate a Federal Implementation Plan ("FIP") in its place. The current Proposed Rule is such a FIP.

INGAA and its members have a strong commitment to environmental stewardship and to reducing the interstate gas pipeline industry's NOx emissions. NOx emissions from the interstate natural gas pipeline industry are not only subject to the NAAQS, but to a host of other CAA-based programs. These include emission control technology requirements for new or modified major emitting facilities and compliance with new source performance standards ("NSPS") that require the "best system of emissions reduction."[6] Pursuant to these regulatory requirements and other voluntary measures, INGAA members have collectively achieved significant reductions in NOx emissions.

EPA's Proposed Rule attempts to address the exceedingly complex issue of interstate transport of NOx and its contribution to downwind nonattainment of the 2015 ozone NAAQS from electric generating units ("EGUs") alongside emissions from seven non-EGU industrial sectors. The EGU portion of the Proposed Rule would apply to 25 states, and the non-EGU portion of the Proposed Rule would apply in 23 states, covering a vast and diverse geographic area. The covered states for non-EGU sources are Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New

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[5] CAA § 110(a)(2)(D)(i)(I).

[6] 40 C.F.R. § 52.21(k)(1); 42 U.S.C. §§ 165(a)(4), 169(3); 40 C.F.R. § 165(a)(1)(xiii).

Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.[7] Of the seven non-EGU industries, the only sources directly owned or operated by INGAA's members are RICE in the pipeline transportation of natural gas.[8]

The Proposed Rule would establish NOx limits for stationary, natural gas-fired, spark ignited RICE ("stationary SI engines") within the natural gas pipeline transportation industry that have a maximum rated capacity of 1,000 horsepower ("hp") or greater.[9] The applicable limits would be:

Engine Type and Fuel[10]	**Proposed NOx Emission Limit**	**Additional Information**
Natural Gas Fired Four Stroke Rich Burn ("4SRB")	1.0 g/hp-hr	Limits reviewed ranged between 0.2 and 3.0 g/hp-hr
Natural Gas Four Stroke Lean Burn ("4SLB")	1.5 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0g/hp-hr
Natural Gas Fired Two Stroke Lean Burn ("2SLB")	3.0 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0 g/hp-hr

These emission limits would begin to apply at the start of the 2026 ozone season. EPA states that it has selected these limits based on reviews of reasonably available control technology ("RACT") NOx rules, air permits, and model rules by the Ozone Transport Commission.[11]

EPA asserts that the limit for Natural Gas Fired 4SRB RICE is designed to be achievable through installation and operation of Non-Selective Catalytic Reduction ("NSCR") controls.[12] The limit for Natural Gas 4SLB RICE is designed to be achievable through installation and

[7] 87 Fed. Reg. at 20,039.

[8] The other non-EGU industries are: 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. *Id*.

[9] *Id*. at 20,142.

[10] *Id*. at 20,142, Table VII.C–1.

[11] *Id*. at 20,142.

[12] *Id*.

operation of selective catalytic reduction ("SCR") technology.[13] For Natural Gas Fired 2SLB RICE, EPA states the limit is designed to be achievable with layered combustion controls.[14]

For all of the limits, the Proposed Rule says that the covered RICE can install different emission control technology than the technology selected by EPA so long as the source achieves the applicable emission rate.[15] The cost-effectiveness of each control option appears to have been evaluated against EPA's cost threshold of $7,500 per ton.[16]

The Proposed Rule also includes monitoring and reporting requirements to ensure that the limits are being met at all covered stationary SI engines. The Proposed Rule would require semi-annual performance testing in accordance with 40 C.F.R. § 60.8. RICE would monitor hours of operation and fuel consumption to calculate ongoing compliance.[17] EPA proposes to use a parameter-based monitoring approach, although it requests comment on alternative monitoring systems.[18] Finally, all covered industries would be required to submit electronic copies of 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").[19]

As demonstrated in these comments, many of EPA's assumptions for the pipeline transportation of natural gas industry are seriously flawed and will require substantial changes to the Proposed Rule. Of particular concern, the Proposed Rule reflects a significant

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[13] *Id*.

[14] *Id*. at 20,143.

[15] *Id*. at 20,142.

[16] *Id*. at 20,142-43.

[17] *Id*. at 20,143.

[18] *Id*.

[19] *Id*.

underestimation of the number of affected units and the proposal's resulting emission reductions. That miscalculation leads to inaccurate cost assessments and would result in substantial over-control of the pipeline transportation of natural gas industry in violation of the law. Further, the Proposed Rule does not contain basic and well-demonstrated compliance flexibilities like emissions averaging, and it would impose a compliance deadline for the pipeline natural gas sector that would result in major disruptions to the supply of natural gas. These significant negative impacts on natural gas reliability would result in increased consumer costs of natural gas and could lead to unnecessary facility closures due to unlawful over-control and infeasible compliance deadlines. EPA should remedy these issues, consistent with the case law that allows EPA to tailor its actions to avoid imposing standards that regulated industry cannot possibly meet.[20] In addition to EPA's underestimation of impacted sources and issues that stem from that error, there are a number of technical issues raised by the Proposed Rule that the Agency can easily remedy, thereby avoiding unnecessary hardship for the industry while maintaining the environmental integrity of the proposed regulatory program. Some of these technical issues are raised in requests for comment by EPA, and others are already reflected in the preamble or the proposed regulatory text.

Although INGAA recognizes that EPA wishes to proceed with this rulemaking to timely address ozone nonattainment in downwind states by the relevant deadlines, INGAA respectfully suggests that EPA take the time needed to develop a well-supported final rule. In accordance with the CAA, a number of states submitted their SIPs before the October 1, 2018 deadline.[21] But EPA failed to take action on these SIPs within the timelines required of it—as evidenced by

[20] *Wisconsin v. EPA*, 938 F.3d 303, 367 (D.C. Cir. 2019).

[21] 87 Fed. Reg. at 20,058.

the four deadline suits that were filed against the agency.[22] More than 12 months after its approval or disapproval was required, on February 22, 2022, EPA proposed to disapprove 19 good neighbor plan SIP submissions.[23] Under the consent decrees for three of these suits, EPA was required to take final action on SIP submissions by April 30, 2022 (or, if it proposed to disapprove any SIP submissions and proposed a replacement FIP by February 28, 2022, the deadline would be extended to December 30, 2022). For seven other states, on December 5, 2019, EPA published a rule finding these states failed to submit or otherwise make complete SIP submissions, thereby requiring the agency to promulgate a FIP no later than January 6, 2022, unless prior to that time, the state made a submission to meet the requirements of CAA section 110(a)(2)(D)(i)(I) and EPA fully approved such submission.[24] However, it wasn't until April 6, 2022, that EPA published the Proposed Rule.[25] Rushing to finalize the Proposed Rule to make up for previously missed deadlines should not be done at the expense of a reasoned and defensible rule. Pushing forward a rule simply to meet deadlines will have unintended consequences that will negatively impact regulated parties and improperly shift EPA's burden to industry. Additionally, rushing the Proposed Rule invites litigation alleging that EPA has acted arbitrarily and capriciously. These are all outcomes that can and should be avoided. While it may take longer to finalize a rule after carefully considering industry's comments, including those

[22] *See id*. at 20,057 n.69 (noting there are consent decrees related to three of these suits: *New York et al. v. Regan,* (No. 1:21–CV–00252, S.D.N.Y.), *Downwinders at Risk v. Regan*, (No. 21–cv–03551, N.D. Cal.); *Our Children's Earth Foundation v. EPA*, (No. 20–8232, S.D.N.Y.)). The fourth deadline suit was filed on March 8, 2022, to compel EPA to perform its non-discretionary duty to promulgate a good neighbor FIP for New Mexico: *Wildearth Guardians v. Regan*, (No. 22-cv-174, D.N.M.)

[23] *See id.* at 20,057 n.75.

[24] *See* 42 U.S.C. § 7410(c)(1)(A).

[25] 87 Fed. Reg. at 20,057-58.

contained herein, any such delay is not unreasonable in light of the complexity of the Proposed Rule. EPA must take the time to do this correctly.

For all of these reasons, INGAA strongly advises that EPA address the concerns raised in these comments. INGAA requests that EPA withdraw the proposal and offer a new proposed rule that substantially revises its regulatory approach.

II. EPA Has Vastly Underestimated the Number of Engines that Would Be Subject to its Proposed Rule, Resulting in Serious Ramifications for Industry and the Validity of the Proposal.

In the preamble and supporting documentation, EPA estimates that there are 307 affected units in this sector.[26] Based on review of INGAA member information, it is apparent that EPA has significantly underestimated the impacts of the Proposed Rule for natural gas transmission and storage companies by miscounting the number of affected units. As these comments explain, EPA's Proposed Rule would in fact apply to nearly five times the number of units that EPA assumes, vastly increasing the costs and time for compliance with the Proposed Rule and requiring more than twice as many emission reductions than EPA believes are necessary. INGAA understands that these results were not EPA's intention and that EPA's interest is in appropriately controlling only the most significant sources of NOx emissions in the pipeline transportation of natural gas sector. We expect the Agency would agree that the Proposed Rule must be substantially revised to address the incorrect factual underpinnings of the

[26] *See, e.g.*, *id*. at 20,090.

proposal and to achieve the Agency's policy goals—including the overall amount of NOx emission reductions—that EPA has identified as appropriate for this rulemaking.

These comments will help EPA to address those issues. Based on information currently available to INGAA members,[27] an estimate of actual unit counts and resulting emissions reductions was prepared:

- 1,199 engines owned or operated by INGAA members in natural gas transmission and storage would require control. **This is four times the EPA estimate.**

- Approximately 181 additional engines owned or operated by INGAA members currently include emission controls but cannot meet the proposed NOx limits, thus requiring incremental control. **The collective total of 1,380 reciprocating engines owned or operated by INGAA members requiring NOx control is 4.5 times EPA's estimate.**

- Another 678 units owned or operated by INGAA members that meet the emission limits would incur incremental compliance costs to address Proposed Rule requirements for biannual emissions tests and continuous parameter monitoring. For controlled units, compliance is typically based on an annual emissions test, and parameter monitoring is not typically required.

- While EPA projects NOx reductions of 55,546 tons per year ("TPY") for all covered states combined, INGAA's estimate indicates **additional reductions** in most states and total reductions of **over 57,000 TPY more than EPA's estimate**. This is more than double (203.4%) the reductions EPA estimates.[28]

As shown below, significant disparities exist in all states where pipeline transportation RICE are common. These disparities are of such a nature and magnitude that they require serious

[27] Although the comment period has limited the amount of information that INGAA has been able to compile at this time, INGAA would be pleased to continue to work with EPA to further evaluate the number of affected units and to help the Agency develop rule provisions that better reflect the realities of the industry. While initial information has been gathered on affected unit counts and location, the comment schedule precluded the ability to conduct a detailed, state-by-state analysis of EPA's underestimation of NOx reductions and costs.

[28] INGAA members account for 79 percent of the RICE included in EPA's list of 307 units, and INGAA members comprise the vast majority of interstate natural gas transmission companies, but these estimates do not include pipeline companies that are not INGAA members. In addition, INGAA data estimates are from transmission and storage operations and do not include RICE in the gathering and boosting segment located between the gas production and gas processing segments. RICE in gathering and boosting would also be affected units based on the proposed definition of "pipeline transportation of natural gas" in section 52.41(a). Many additional units would be affected in that segment, and the total count of affected units may be more than double the values presented above for transmission and storage facilities operated by INGAA members.

reconsideration of key aspects of the Proposed Rule and the proposed approach to regulating the natural gas pipeline transportation sector. EPA might, for instance, address some of these issues by revising the hp applicability threshold for affected units to more appropriately target sources with significant annual emissions. EPA might also further refine the definition of "affected unit." Because the issues identified in these comments are so central to EPA's proposed action, the Agency should also consider issuing a supplemental proposal for the natural gas pipeline transportation portion of the Proposed Rule. INGAA believes such an approach is warranted.

A. EPA's State-by-State Unit Counts Differ Significantly from Data Available to INGAA and its Members.

INGAA compiled a state-by-state assessment of affected units for comparison to EPA estimates.[29] Table 1 provides a comparison of EPA unit counts for the pipeline transportation of natural gas sector to INGAA-compiled counts of affected RICE requiring control (i.e., currently uncontrolled), as well as units with NOx emission controls in place that would require additional control to meet the proposed NOx standard.[30]

Table 1. State-level comparison of EPA count of affected pipeline transportation reciprocating engines to actual INGAA member count of units requiring NOx control or incremental control.

	AR	IL	IN	KY	LA	MI	MN	MS	MO	NY	OH	OK	PA	TX	UT	VA	WV	WI	WY
EPA	10	22	3	17	45	21	9	25	22	2	25	32	7	26	4	9	20	0	6
INGAA[1]	52	51	46	121	191	95	37	218	32	12	79	38	1	70	10	25	87	11	23
INGAA[2]	0	11	0	0	13	0	0	7	0	17	19	1	57	45	0	0	0	0	3

[29] EPA data is available from docket document number EPA-HQ-OAR-2021-0668-0191, which includes a technical memorandum and an Excel file identifying affected non-EGU units. "Technical Memorandum Describing Relationship between Proposed Applicability Criteria for Non-EGU Emissions Units Subject to the Proposed Rule and EPA's *'Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'*" (Mar. 30, 2022).

[30] Four of the 23 states with non-EGU controls are not shown in Table 1 (California, Maryland, Nevada, and New Jersey have no, or limited, units). EPA estimates one affected unit in California, and INGAA estimates four units, but all are controlled. In Maryland, EPA estimates one unit; INGAA data indicate no uncontrolled units and 14 units that would meet the proposed standard. EPA estimates no affected units in Nevada and New Jersey. INGAA data indicate there are a total of four controlled units in Nevada and New Jersey, and eight New Jersey units with emission controls in place that would require additional control to meet the proposed standard.

INGAA[1]: Count of reciprocating engines requiring NOx control.
INGAA[2]: Count of units with NOx control installed that do not meet the proposed limits and would require incremental control.

These data discrepancies demonstrate, even at this high level of detail, the serious nature of the flaws in the current basis of support for the Proposed Rule. When an agency relies on a fatally flawed factual record as the justification for a regulation, that regulation is inherently arbitrary and capricious.[31] This underscores the need for EPA to substantially revise, if not re-propose, the Proposed Rule.

B. EPA Has Miscounted Affected Units Because its Applicability Threshold Does Not Take Utilization into Account.

EPA explains that a NOx emission rate of 100 TPY provided the screening basis for identifying affected units. For pipeline transportation RICE, EPA equates that emission rate with the 1,000 hp applicability threshold in the Proposed Rule. This assumption is incorrect, and it has distorted much of what flows from it in the Proposed Rule. In particular, this error would inadvertently pull far more sources into the scope of the program than EPA apparently intends, leading to serious compliance concerns, unnecessary emission reductions and unlawful over-control. This serious flaw is another reason for EPA to withdraw or substantially revise the Proposed Rule.

For EPA's assumption to be accurate, an uncontrolled unit would need to operate a significant portion of the year, but that is not consistent with interstate natural gas transmission operations. For example, depending on the uncontrolled NOx emission factor used (*e.g.*, EPA AP-42 factor versus EPA factor from NOx SIP Call Phase 2 rule), a 1,000 hp two-stroke lean

[31] *Almay, Inc. v. Califano*, 569 F.2d 674, 682 (D.C. Cir. 1977) (regulation was arbitrary and capricious because it relied heavily on discredited study); *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923,935 (5th Cir. 1998) ("A regulation cannot stand if it is based on a flawed, inaccurate, or misapplied study.").

burn engine would need to operate 62 percent to 86 percent of the year to emit 100 TPY. Actual operations are often much less than 25 percent of the year for gas transmission RICE in this size range, and ozone season operation may be very low for pipelines serving markets with lower gas demand in the summer. Transmission compressor stations are designed to meet peak demand days and typically include significant over-capacity.[32] This results in average annual utilization on the order of 40–45 percent for most natural gas transmission pipelines, with some units within the system operating minimally—*e.g.*, only when needed during peak demand during cold winter weather events.

Utilization data is not readily available for all units, but there are data sources available that demonstrate utilization for natural gas transmission and storage operations. For example, compressor stations that report greenhouse gas ("GHG") emissions to EPA under Subpart W of the GHG Reporting Program ("GHGRP") report annual hours in operating mode, standby-pressurized mode, and shutdown depressurized mode for each unit at the affected facility. A white paper[33] from the Pipeline Research Council International ("PRCI") compiled Subpart W utilization data for hundreds of affected facilities over six years, and those results are presented in Figure 1. For completeness, turbine data is included as well as RICE data. The figure shows the percentage of units with utilization in ten different "bins," from zero to 100 percent utilization. The data show that about 2/3 of transmission RICE units operate less than 50 percent of the time, with nearly 25 percent operating less than 10 percent of the time. For RICE at

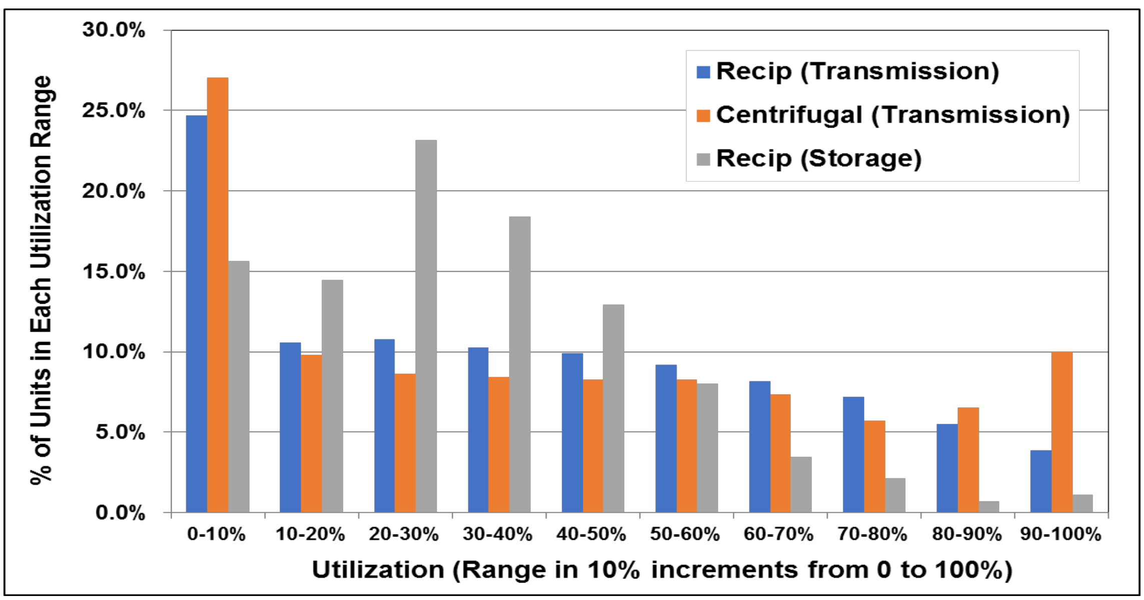
[32] It should be noted that sources within the industry cannot generally accept enforceable limitations on operations because FERC certificate requirements demand that these units be available to operate at capacities well-above typical operating conditions. These units nevertheless can effectively address emissions through the use of emissions averaging. *See* section IV for additional discussion.

[33] PRCI White Paper, "Use of Probabilistic Statistical Techniques for Estimating NOx Emissions from Infrequently Operated Emission Units," Catalogue No. PR-312-18208-E01 (Apr. 2020).

storage facilities, over 80 percent of the units operate less than 50 percent of the time. The GHGRP reporting threshold captures larger facilities with higher utilization because emissions from combustion are the driver that results in a facility exceeding the 25,000 metric ton reporting threshold. Thus, these data from GHGRP affected facilities *over-estimate* utilization for the entire population of RICE at natural gas transmission and storage facilities that will be impacted by the Proposed Rule.

Another important characteristic to understand for natural gas transmission compressor stations is that the smaller affected units (*e.g.*, those between 1,000 hp and 2,000 hp) are also more likely to be units that operate less frequently and thus have lower annual and ozone season emissions. A RICE compressor station typically includes several units, and, when demand is low, many or all units will be idle. Facility-specific cases differ, but typically the RICE with *lowest* utilization are the *smaller* affected RICE at the facility.

Figure 1. Histogram of RICE and turbine utilization at natural gas transmission and storage facilities subject to the federal GHGRP reporting program.



Since a 1,000 hp RICE must operate approximately 65 percent of the time or more to emit 100 TPY, and actual operation is much lower for the vast majority of such units, this characteristic utilization profile is the reason that significantly more units are affected by the proposed 1,000 hp threshold than a more reasonable threshold that considers actual emissions and/or unit utilization. If an hp threshold is used as a proxy to identify affected units, *i.e.*, those with 100 TPY or more of annual NOx emissions, utilization should be factored into that threshold.

In sum, more than five times[34] as many RICE units are affected than EPA estimated because characteristic natural gas transmission RICE utilization was not properly considered when defining the 1,000 hp threshold. This threshold therefore results in control of units EPA did not intend to regulate and emission reductions that are not needed to remedy significant contribution. EPA must, therefore, reevaluate the threshold and develop a proposal that better reflects the realities of the industry.

C. Estimates of State-Level NOx Reductions Demonstrate the Proposed Rule Requires Revision.

The comments above demonstrate the significant under-estimation of affected gas transmission RICE counts for states with non-EGU emissions reduction requirements. Based on an understanding of affected units, (average uncontrolled (or "under-controlled") emissions, typical utilization, and average size (hp) by unit type), the potential NOx reductions can be estimated for every state and compared to EPA estimates. The assumptions for this analysis are shown in Table 2.

[34] As noted above, based on INGAA member data, nearly five times as many units require NOx control or incremental control than EPA estimated. INGAA members account for about 80 percent of EPA's 307 units and the vast majority of the other 20% are in interstate natural gas transmission service. Thus, for gas transmission alone, the total count is likely more than 5 times EPA's estimate. Gathering and boosting could add many hundreds to more than a thousand additional units, significantly inflating the affected unit count relative to EPA's estimate.

Table 2. Assumptions by Engine Type for NOx Reduction Estimates by State

Engine Type	Uncontrolled NOx (g/bhp-hr)	% Reduction	"Under-Controlled" NOx (g/bhp-hr)	% Reduction	Avg HP	Utilization (%)
2SLB	16.8	82%	5.0	50	2,500	35%
4SLB	12.0	90%	4.0	65	2,700	25%
4SRB	11.0	94%	2.0	50	1,400	35%

These are relatively conservative assumptions. For example:

- The uncontrolled baseline for four-stroke engines may be higher.
- Assuming 82 percent control for 2SLB engines, which are the most prevalent units, while EPA typically assumes >95 percent control).
- Utilization may be higher than estimated.
- Average size (hp) of the units may be larger.[35]

A more detailed analysis with unit-specific data may result in larger NOx emission reductions for each state or at least some states. Based on INGAA member unit counts and these assumptions, the reductions by state are shown in Table 3. While EPA projects NOx reductions of 55,546 TPY for all covered states combined, INGAA's estimate indicates additional reductions in most states and total reductions of over 57,000 TPY more than EPA's estimate. This is more than double (203.4 percent) the reductions EPA estimates.[36]

[35] These factors also contribute to EPA-estimated emission reductions in some states exceeding estimates based on INGAA data, even though INGAA data show EPA under-counted units in those states (*see, e.g.*, Missouri and Oklahoma data in Table 3). For Oklahoma, EPA estimated reductions may be higher due to the average unit size (information is not complete, but Oklahoma units appear to be larger than the average from Table 2) and assumed control (82 percent assumed versus 97 percent assumption by EPA for 2SLBs). For Missouri, nearly all of the units appear to be 2SLB, so the assumed percent reduction differences (82 percent versus >95 percent in most cases) likely contributes to EPA estimating more reductions than a calculation based on the assumptions above. For the NOx SIP Call Phase 2 rule in 2004, natural gas transmission stakeholders, including INGAA, conducted very detailed analysis for all potentially affected units, which provided a clear understanding of the assumptions discussed above. That task would be a significant undertaking that cannot be completed within the comment period for the Proposed Rule. INGAA, however, offers its continuing assistance to help EPA better understand the inventory of equipment and associated emissions and reductions for this rulemaking.

[36] INGAA's estimate would be higher if a higher 4SLB engine baseline is assumed, higher control levels (*i.e.*, >95 percent control is commonly applied in EPA's estimate) are assumed, average size (hp) is larger than assumed, or if average utilization exceeds the assumed values shown in Table 2.

Table 3. Estimated emission reductions by state based on INGAA member unit counts and average assumptions for unit size, NOx baseline, and reduction.

State	EPA Unit Count	INGAA Unit Count: Uncontrolled	INGAA Count: Existing Control Insufficient	EPA NOx Reductions (TPY)	INGAA NOx Reductions	NOx Difference (TPY)	NOx TPY Overage (%)
AR	10	52	0	2,083	6,053	3,970	191%
CA	1	0	0	328	0	(328)	NA
IL	22	51	11	3,158	5,559	2,401	76%
IN	3	46	0	364	4,334	3,970	1092%
KY	17	121	0	5,497	9,665	4,168	76%
LA	45	191	13	9,395	11,485	2,090	22%
MD	1	0	0	107	0	(107)	NA
MI	21	95	0	5,452	9,071	3,619	66%
MN	9	37	0	1,340	4,077	2,737	204%
MS	25	218	7	3,784	19,954	16,680	427%
MO	22	32	0	3,793	3,004	(789)	-21%
NV	0	0	0	0	0	0	NA
NJ	0	0	8	0	136	136	NA
NY	2	12	17	254	1,385	1,131	444%
OH	25	79	19	2,875	9,197	6,322	220%
OK	32	38	1	6,717	3,828	(2,889)	-43%
PA	7	1	57	1,025	564	(461)	-45%
TX	26	70	45	4,167	8,105	3,938	95%
UT	4	10	0	569	867	298	52%
VA	9	25	0	1,922	2,864	942	49%
WV	20	87	0	1,803	9,030	7,227	401%
WI	0	11	0	0	1,142	1,142	NA
WY	6	23	3	912	2,646	1,734	190%
Total	307	1,199	181	55,546	112,967	57,421	203%

These estimates, which show more than double the emission reductions that EPA has proposed to determine would be a full remedy for any significant contribution to downwind nonattainment or maintenance issues for the pipeline transportation of natural gas sector, again make clear that the basis for the Proposed Rule is so flawed that EPA must withdraw or substantially revise the proposal.

D. NOx Emissions, Potential NOx Reductions, and Cost Implications for Affected Units in Pennsylvania and Louisiana.

As noted previously, the comment period did not provide adequate time to complete unit-level analysis of emissions implications for all states, but a detailed analysis was conducted for two states with differing historical requirements, Pennsylvania and Louisiana, to provide EPA with additional detail and to further demonstrate that the factual basis on which EPA has relied is too flawed to reasonably form the basis for a proposed rule. In Louisiana, many gas transmission units are uncontrolled or only marginally controlled. In contrast, a Pennsylvania NOx RACT rule has resulted in installation of NOx controls on the majority of units, with some units not meeting the Proposed Rule limits due to marginally higher emission standards in Pennsylvania or unit-level compliance via emissions averaging or alternative RACT.

For Louisiana units:

- EPA estimates that there are 45 affected units, but INGAA member data indicate there are 204 units that would require control, and most of the units are currently uncontrolled (191 of 204).

- However, many units exhibit very low utilization, so actual annual NOx emissions are well below 100 TPY. **Actual utilization for the 204 units was approximately 23%** of potential operations (*i.e.*, based on annual hp-hours). This is indicative of "actual emissions" less than 100 TPY for most units, as compared to the 1,000 hp applicability threshold that assumes utilization more than three times higher.

- EPA estimates **9,395 TPY** of NOx emission reductions from the 45 units with an uncontrolled baseline of 9,823 TPY, which is equivalent to 95.6 percent reduction on average.

- Based on INGAA member data and more realistic average reductions, NOx reductions are estimated at approximately **11,485, TPY**. If EPA's assumption is used (95.6 percent average reduction), NOx reductions are **14,105 TPY**.

- Note that these reductions include nominal amounts for many units with very little operating time. **Over 77 percent of the units operated less than 40 percent of the time.**

- The estimated cost for retrofitting 192 uncontrolled units in Louisiana likely exceeds $400 million. The types and sizes of units in Louisiana are similar to the full fleet of gas transmission RICE affected, so extrapolating this to 1,199 uncontrolled units (*see* Table 3) indicates a total capital cost of $3 billion or more for RICE affected by the Proposed Rule operated by INGAA members.

For Pennsylvania units:

- EPA estimates seven affected units in Pennsylvania, achieving **1,025 TPY of NOx reductions** based on 95.4 percent average control.

- Pennsylvania units include emissions control, but INGAA member data indicate there are 57 units with emissions marginally above the proposed standards (*e.g.*, 2–5 g/bhp-hr) that would require additional capital expenditure to further reduce NOx to meet the proposed standards. One unit is uncontrolled but will likely be installing controls to meet an update to Pennsylvania's NOx RACT rule.

- **Actual utilization for the 58 units was approximately 34 percent** of potential operations on an annual hp-hour basis. Because the units include NOx control and utilization is relatively low, actual emissions are less than 100 TPY for all units but one.

- EPA estimates **1,025 TPY** of NOx emission reductions from the 7 units with an uncontrolled baseline of 1,077 TPY, which is equivalent to 95.4 percent reduction on average.

- Based on INGAA member data, NOx reductions are estimated at approximately **611 TPY** with an average emission reduction of about 47 percent.

  - Note that these reductions include nominal amounts for units that already include emission controls. In addition, about 40 percent of the units operated less than 40 percent of the time.

III. Without Appropriate Revisions, the Proposed Rule Will Result in Unlawful Over-Control of the Pipeline Transportation of Natural Gas Sector.

The U.S. Supreme Court has made clear that EPA has an obligation to avoid "over-control" of upwind sources when it chooses to regulate pursuant to the good neighbor provision of the CAA to address interstate transport and downwind nonattainment or interference with maintenance.[37] That means that upwind states cannot be required to reduce their emissions below their levels of significant contribution to downwind nonattainment. In other words, all of the work to achieve attainment with the NAAQS cannot be left to upwind states. Downwind states must do their part as well.

The Supreme Court's ruling in *EME Homer II* provided EPA with some leeway to address the over-control issue. It noted 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. The Court explained that:

> a degree of imprecision is inevitable in tackling the problem of interstate air pollution. Slight changes in wind patterns or energy consumption, for example, may vary downwind air quality in ways EPA might not have anticipated. The Good Neighbor Provision requires EPA to seek downwind attainment of NAAQS notwithstanding the uncertainties. Hence, some amount of over-control, *i.e.,* emission budgets that turn out to be more demanding than necessary, would not be surprising. Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate.[38]

This "leeway" the Supreme Court explained, might allow EPA to require emissions reductions in an upwind state that could result in over-control relative to a downwind receptor in one state so long as those upwind reductions were still necessary to eliminate significant contribution at another receptor in another state. This sort of incidental over-control, the Supreme Court held, might still be consistent with the CAA's good neighbor provision. What would clearly be impermissible, the Court held, is an interstate transport rule that "requires an upwind State to reduce emissions by more than the amount necessary to achieve attainment in *every* downwind State to which it is linked."[39] Between these two extremes identified by the

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[37] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 523 (2014) ("*EME Homer II*").

[38] *Id*.

[39] *Id*.

Supreme Court, the record that EPA develops to support an interstate transport rule must certainly provide a legitimate basis for concluding that the Agency has struck a reasonable balance between potential over- and under-control, and that EPA has rational reasons for concluding that its rule will not result in either unlawful outcome. The Proposed Rule here does not appropriately strike that balance for natural gas transportation pipelines.

A. INGAA's Analysis Demonstrates the Proposed Rule Would Over-Control the Pipeline Transportation of Natural Gas Sector.

As demonstrated in section II above, EPA's Proposed Rule would require significantly more emission reductions on a national and a state-by-state basis than the Agency has assumed. On a national basis, EPA has calculated that its Proposed Rule would result in 55,546 TPY of NOx reductions from the pipeline transportation of natural gas sector. INGAA's analysis shows that the Proposed Rule would result in NOx reductions of at least approximately 112,967 TPY. EPA's national NOx reduction estimate is, therefore, off by *at least* an approximate 57,421 TPY. If EPA believes, as it must, that national NOx emission reductions on the order of 55,546 TPY are necessary to address the significant contribution of the pipeline industry in the 23 states covered by the non-EGU provisions of the Proposed Rule, then surely a rule that would result in reductions more than twice that amount would result in over-control.

The state-by-state estimates provided above further confirm that the Proposed Rule would result in over-control with respect to the natural gas pipeline transportation industry. Of the 23 states included in the non-EGU program, four states (California, Maryland, Nevada, and New Jersey) have very limited data, or no units owned or operated by INGAA members. INGAA has therefore not further evaluated them. Of the remaining 19 states, INGAA's analysis shows that 16 would be subjected to NOx emission reductions that are higher—in many cases substantially higher—than EPA has estimated the Proposed Rule would require.[40] The overages range from 22 percent to 1,092 percent, with nine of the overages over 100 percent. This is not incidental over-control that results by virtue of an upwind state being linked to more than one downwind state. This over-control has resulted from EPA's pervasive misunderstanding of the fundamental attributes of the natural gas pipeline transportation sector.

The conclusion that the Proposed Rule would result in over-control is not simply based on the sizeable difference between EPA's estimated emission reductions and the emission reductions that INGAA projects based on its more complete and accurate data. The CAA requires EPA, when acting pursuant to the good neighbor provision, to clearly identify "significant contribution" in terms of overall emission reductions that sources and states must achieve.[41] EPA does this by applying a cost-effective control analysis to the sources it chooses to regulate.[42] That analysis for this Proposed Rule identified a level of significant contribution from the pipeline transportation of natural gas sector consistent with national emission reductions of 55,546 TPY and state-by-state emission reductions calculated by EPA as set forth in Table 3 above. Flaws in the record have caused EPA to inadvertently propose to pull in sources and require emission reductions far in excess of what the Agency believes amounts to significant contribution. That is over-control, and eliminating it by revising the Proposed Rule will help

[40] Three states—Missouri, Oklahoma, and Pennsylvania—are expected to achieve fewer emission reductions than EPA has projected. INGAA's analysis shows EPA has estimated reduction overages of 37, 29, and 45 percent, respectively. As explained above, this is almost certainly due to a combination of factors, including that the sources in these states are either controlled pursuant to RACT and differences in unit-type and size. *See* footnote 35 above.

[41] *North Carolina v. EPA*, 531 F.3d 896, 908 (D.C. Cir. 2008) ("It is unclear how EPA can assure that the trading programs it has designed … will achieve section 110(a)(2)(D)(i)(I)'s goals if we do not know what each upwind state's 'significant contribution' is to another state.").

[42] *See, e.g.*, 87 Fed. Reg. at 20,055.

EPA achieve the emission reductions that are warranted without undue hardship on industry and protracted legal battles over these issues.

B. Additional Considerations Do Not Undercut the Conclusion that the Proposed Rule Would Result in Over-Control.

It is also important to emphasize that EPA's underestimation of affected units and emission reductions does not stem from a misunderstanding of the pipeline transportation of natural gas sector's overall NOx emissions. On the contrary, EPA's national emissions inventory for the source category is complete. As explained above, the primary reason that the Proposed Rule would control more sources and result in more reductions than EPA expected is the Agency's lack of information on unit utilization and the Proposed Rule's flawed applicability threshold. The Agency does know exactly how many NOx emissions are at issue and what emission reductions (approximately 55,546 TPY) may be needed to address significant contribution.

Additionally, the over-control analysis presented in the Proposed Rule does not adequately address the issue and cannot counter the conclusion that the pipeline transportation of natural gas sector would be over-controlled under the Proposed Rule. EPA's analysis looks only at the emission reductions it has assumed. Because the record for the pipeline transportation of natural gas sector is so flawed, it does not speak to the actual effects of the proposal in the real world.

It is also important to discuss the manner in which the courts have previously addressed over-control issues. In *EME Homer II*, the Supreme Court determined that potential over-control did not warrant invalidation of a good neighbor rule "on its face" and that instead it was appropriate to contest over-control of individual upwind states in "particularized, as-applied challenge[s]."[43] While that was the appropriate remedy for the rule in question in that earlier litigation, it is not the necessary or appropriate approach here. In particular, state-specific, as-applied challenges were needed during the previous round of transport rule litigation because the petitioners there argued only that EPA's methodology for devising state budgets, using uniform emission control costs to select reasonable controls and to model budgets that reflect the installation and operation of those controls, had the *potential* to result in over-control.[44] Here, EPA has identified tonnage reductions from the pipeline transportation of natural gas sector that it believes will address the industry's significant contribution to downwind nonattainment, but inadvertently proposed requirements that would impose vastly larger reduction requirements. There is not just potential for over-control, as there was under previous versions of CSAPR. Over-control is guaranteed. As such, state-by-state as applied challenges are not necessary to demonstrate over-control.[45]

Finally, EPA should consider that the controls to be installed to comply with the Proposed Rule would operate year-round, not just during the ozone season. Although the Proposed Rule is concerned with ozone season reductions and those are the reductions needed to address significant contribution, EPA should acknowledge that the rule will result in additional reductions, and the Agency could find some manner to credit the sector for those additional reductions.

Because EPA's Proposed Rule will result in unlawful over-control, INGAA requests that the Agency reevaluate the control requirements it has proposed. One approach that could address

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[43] *EME Homer II*, 572 U.S. at 524.

[44] *EME Homer III*, 795 F.3d at 126.

[45] A particularized as-applied challenge is appropriate "for challengers who raise the possibility of overcontrol in only a few instances," where petitioners "speculate" that EPA's methodology could lead to over-control. *Wisconsin v. Env't Prot. Agency*, 938 F.3d 303, 325 (D.C. Cir. 2019).

the issue of over-control would be raising the hp threshold for the Proposed Rule's applicability. Taking this approach, EPA could more effectively target those uncontrolled sources that emit more than 100 TPY. Determining an appropriate threshold with precision could involve additional technical analysis, and INGAA would be happy to assist EPA in that effort. Whichever approach EPA ultimately chooses, INGAA encourages the Agency to work collaboratively with the industry to identify regulatory requirements that will achieve meaningful environmental benefits consistent with EPA's legal obligation to address significant contribution without improper over-control.

IV. The Proposed Rule Should Be Revised to Provide Cost-Effective and Environmentally Sound Compliance Flexibility Consistent with Other EPA and State Regulatory Policies.

Because eliminating the significant contributions of upwind state sources to downwind state nonattainment and interference with maintenance poses many challenges, EPA has consistently sought to provide sources as much flexibility as possible. For electric utilities, EPA has consistently acknowledged the need to provide flexibility through emission allowance trading programs to address interstate transport.[46] For the natural gas pipeline transportation sector, EPA has historically provided regulatory flexibility through emissions averaging.[47] EPA should take that approach here.

[46] EPA adopted a trading program approach in the 1998 NOx SIP Call, 2005 Clean Air Interstate Rule ("CAIR"), 2011 Cross-State Air Pollution Rule, 2016 CSAPR Update, the 2018 CSAPR Closeout, and it is the approach EPA has proposed for EGU provisions of the Proposed Rule.

[47] INGAA supports EPA's decision to separate the EGU and natural gas transportation programs. EPA identified reasons (lack of data, lack of CEMS) for not including the natural gas pipeline industry in the EGU trading program. INGAA agrees that incorporating the pipeline transportation of natural gas industry into the EGU program would be unnecessarily complicated. Nevertheless, INGAA believes other forms of flexibility are necessary and that they would enhance the environmental benefits of the program.

A. EPA Precedent Supports Use of Averaging.

If EPA moves forward with the Proposed Rule, INGAA recommends EPA adopt emissions averaging, as it did in the NOx SIP Call Phase 2 rule, which demonstrated real and lasting emission reductions in an efficient manner. Starting in 1998, EPA's NOx SIP Call rule included control requirements for large stationary internal combustion engines.[48] INGAA challenged aspects of the 1998 NOx SIP Call, and the D.C. Circuit remanded the 1998 NOx SIP Call to EPA with respect to INGAA's challenge.[49]

In response to the court's decision and in support of EPA's action on remand, INGAA engaged in extensive discussions with the Agency to help design the elements of a replacement rulemaking. That resulted in the development of the 2004 NOx SIP Call Phase 2 rule. There, EPA evaluated and came to support reliance on emissions averaging for RICE in the natural gas pipeline sector as a reasonable compliance flexibility mechanism. The Phase 2 rule, like the Proposed Rule, was developed to address the interstate transport of ozone and required 21 states and the District of Columbia to eliminate NOx emissions that contributed significantly to downwind nonattainment of the 1-hour ozone standard. As such, the emissions averaging provisions used to implement the Phase 2 NOx SIP Call rule are particularly relevant to implementation of the Proposed Rule.

EPA first addressed in detail the issue of emissions averaging for the purpose of addressing interstate transport in an August 22, 2002 guidance memorandum[50] that was intended to help states developing SIPs respond to NOx SIP Call. The memo says that "[w]here states

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[48] 63 Fed. Reg. 57,356 (Oct. 27, 1998).

[49] *See Michigan v. EPA*, 213 F.3d 663, 693, 695 (D.C. Cir. 2000).

[50] Memorandum from Lydia N. Wegman, "State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NOx) – Stationary Reciprocating Internal Combustion Engines" (Aug. 22, 2002) ("Wegman Memo").

choose to regulate large IC engines, EPA encourages states to allow owners and operators of large IC engines the flexibility to achieve the NOx ton/season reductions" by using a variety of control technologies, noting that while control technologies are known to have "a specific average control effectiveness for an engine population, some individual engines that install the controls would be expected to be above and some below that average control level, simply because it is an average."[51] For that reason, EPA stated:

> During the SIP development process the States may establish a *NOx tons/season emissions decrease target for individual companies and then provide the companies with the opportunity to develop a plan that would achieve the needed emissions reductions*. The companies may select from a variety of control measures to apply at their various emission units in the State or portion of the State affected under the NOx SIP call. These control measures would be adopted as part of the SIP and must yield enforceable and demonstrable reductions equal to the NOx tons/season reductions required by the State. *What is important from EPA's perspective is that the State, through a SIP revision, demonstrate that all the control measures contained in the SIP are collectively adequate to provide for compliance with the State's NOx budget during the 2007 ozone season*.[52]

Accordingly, in one of EPA's earliest rulemakings to address interstate transport for the ozone NAAQS, the Agency embraced emissions averaging for RICE on an individual company basis. In its 2004 final rule for the Phase 2 NOx SIP Call, EPA adopted the position stated in the Wegman memo, using almost exactly the same language.[53] As described in the final Phase 2 rule, commenters on the proposal provided additional well-reasoned rationales for allowing RICE to use emissions averaging for purposes of meeting their interstate transport obligations. The commenters noted the following benefits of company-specific emissions averaging:

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[51] *Id*. at 1.

[52] *Id*. at 2 (emphases added).

[53] 69 Fed. Reg. 21,604, 21,621 (Apr. 21, 2004).

- Engine owners and operators would accept enforceable and verifiable measures to control engines to meet assigned NOx SIP Call reductions.

- Based on the company compliance plans, States would be able to clearly demonstrate their compliance with Phase II of the NOx SIP Call.

- The EPA, States, and regulated companies would not have to work through the technical confusion of definitions of lean-burn and rich-burn engines and whether individual engines could in fact achieve certain control levels with a prescribed control technology.

- Compliance with NOx SIP Call requirements could be achieved with minimum impacts on cost, natural gas capacity, and operational reliability.[54]

In furtherance of these goals and to encourage states to adopt SIPs that incorporated emissions averaging for RICE, EPA developed a model rule that states could adopt as part of their SIPs. The model rule was focused on compliance with the rule's emission reduction requirements by 2007 and was based on a "Facility Seasonal NOx 2007 Tonnage Reduction," which EPA defined as "the total of the Engine Seasonal NOx 2007 Tonnage Reductions attributable to all of an owner/operator's Large NOx SIP Call Engines," *i.e.*, the engines subject to the rule's requirements.[55]

As suggested by the language included in the preamble to final Phase 2 rule, the model rule was based on a compliance plan approach. These compliance plans "must demonstrate enforceable emission reductions from one or more stationary internal combustion engines equal to or higher than the Facility Seasonal NOx 2007 Tonnage Reduction."[56] The plan "may cover some or all engines at an individual facility or at several facilities or at all facilities in a State that are in control of the same owner/operator."[57] Interestingly, the model rule allowed facility

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[54] *Id*.

[55] Model Rule § 1(c).

[56] *Id*. § 3(a)(2).

[57] *Id*. § 3(a)(3).

owners to get credit for emission reductions from engines subject to the rule and from other engines:

> The compliance plan may include credit for decreases in NOx emissions from Large NOx SIP Call Engines in the State due to NOx control equipment. Credit may also be included for decreases in NOx emissions from other engines in the State due to NOx control equipment not reflected in the 2007 Ozone Season Base NOx Emissions in the NOx SIP Call Engine Inventory.[58]

Finally, the compliance plan had to include "[a] numerical demonstration that the emission reductions obtained from all engines included under the plan will be equivalent to or greater than the owner/operator's Facility Seasonal NOx 2007 Tonnage Reduction, based on the difference between the Past NOx Emission Rate and the Projected NOx Emission Rate multiplied by the Projected Operating Hours for each Affected Engine."[59]

Since the emissions averaging approach adopted in the NOx SIP Call Phase 2 rule has been demonstrated to achieve real and lasting emission reductions in an efficient manner, state environmental regulatory bodies have adopted similar regulatory approaches. Texas, for instance, has allowed emissions averaging to demonstrate compliance with its emission reduction requirements for grandfathered RICE located in West and East Texas. Those rules generally require each affected engine in East Texas to achieve at least a 50 percent reduction of the hourly emissions rate of NOx and affected engines in West Texas to achieve up to a 20 percent reduction of the hourly emissions rate of NOx.[60] The rules further provide, however, that "the owner or operator of more than one grandfathered reciprocating internal combustion engine may average the reductions achieved among more than one reciprocating internal combustion engine

[58] *Id*. § 3(a)(5).

[59] *Id*. § 3(a)(6)(v).

[60] 30 TAC § 116.779 (b)(1), (2).

connected to or part of a gathering or transmission pipeline in order to demonstrate" the required reductions.[61] The Texas rules even allow averaging across engines located in both East and West Texas so long as the owner or operator demonstrates that "the sum of the reductions achieved from all of the engines located in the East Texas region as defined in §101.330 of this title will achieve the reductions" required of such units.[62]

Pennsylvania has also adopted emissions averaging provisions to address NOx and volatile organic compounds ("VOCs") for purposes of RACT, and EPA has approved those provisions.[63] The Pennsylvania rules provide source-specific RACT determinations or alternative NOx emissions limits for sources at 23 major NOx and VOC emitting facilities within the state to address the 1997 and 2008 8-hour ozone NAAQS. The alternative NOx emission limits include facility-wide or system-wide NOx emissions averaging plans. To assess the effectiveness of averaging, Pennsylvania conducted an evaluation of aggregate NOx emissions emitted by the sources included in the facility-wide or system-wide NOx emissions averaging plan. The state concluded, and EPA agreed, that those emission reductions under the averaging plans would be equivalent to emissions if the individual sources were operating in accordance with the applicable presumptive limit. Accordingly, EPA determined that the averaging plan was consistent with all applicable laws and regulations and approved the plan.

These states are not outliers. On the contrary, a range of geographically diverse states have adopted emissions averaging based on EPA's model rule for control of RICE NOx emissions. Illinois, for instance, allows owners and operators of affected RICE units to comply

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[61] *Id*. § 116.779 (b)(3).

[62] *Id*.

[63] *See* 87 Fed. Reg. 3,929 (Jan. 26, 2022).

with NOx emission limits through an emissions averaging plan.[64] The rule provides equations by which owners and operators must demonstrate that total mass of actual NOx emissions from the units listed in the emissions averaging plan are equal to or less than the total mass of allowable NOx emissions for those units for both the ozone season and calendar year.

New York has also adopted emissions averaging rules.[65] New York's rules require emissions averaging plans to employ a weighted average permissible emission rate and include provisions for adjusting the weighted average to address forced outages. The state's rules also prohibit averaging of emissions from sources within the severe ozone nonattainment area with those outside the severe ozone nonattainment area.

Ohio has adopted similar regulations authorizing owners and operators of affected RICE to comply with NOx emission standards through EPA-approved emissions averaging plans.[66] Ohio's rules require that emission reductions counted under such a plan be "real, quantifiable and enforceable and … in excess of any state or federal requirements."[67] The rules further provide that those emission reductions must be equal to or greater than the actual emission reductions that would be required under Ohio's rules if an emissions averaging program were not employed. Further, Ohio allows an owner or operator to take credit for emission reductions resulting from a unit shutdown only if the owner or operator can demonstrate that "the shutdown does not correspond to load-shifting or other activity which results in or could result in an

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[64] Ill. Admin. Code tit. 35, § 217.390.

[65] 6 NYCRR 227-2.5(b).

[66] Ohio Admin. Code 3745-110-03(I).

[67] *Id.*

equivalent or greater emission increase and that the reduction accounts for any increase in NOx emissions from other sources as a result of the shutdown."[68]

Finally, in addition to EPA's model rule, the Ozone Transport Commission ("OTC") has developed its own NOx RACT technical guidelines for RICE used in natural gas transmission.[69] The OTC guidelines provide emission rate limits that would apply to various types and sizes of RICE. They also include provisions that would authorize emissions averaging for multiple natural gas-fueled units that are under the control of a common owner or operator at a single facility to achieve the same level of NOx reductions that would be achieved if all of the units at the location met the applicable NOx emissions limitations of the guidelines.[70] As EPA has relied on OTC model rules to establish the emission rate limits proposed in this Proposed Rule, EPA should likewise adopt emission averaging as a compliance measure based on OTC approval of that approach.

B. Averaging Will Help to Address Otherwise Insurmountable Obstacles to Compliance with the Proposed Rule.

EPA has proposed to require non-EGU sources to comply with the Proposed Rule's emission limits beginning in 2026. As explained in section V of these comments, INGAA does not believe EPA has established record support for the feasibility of a 2026 compliance deadline. Indeed, there is no realistic pathway to retrofitting every affected unit with the controls necessary to meet EPA's proposed emission limits. The compliance deadline is not, however, the only practical impediment to compliance for INGAA members. Units of certain vintages and units

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[68] *Id*. at 3745-110-03(I)(1)(e).

[69] OTC, "OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NOx) Emissions from Natural Gas Pipeline Compressor Fuel- Fired Prime Movers," (May 14, 2019), available at https://otcair.org/upload/Documents/Model%20Rules/OTC_RegAndTechGuideline_NGPipelineCompressorPrimeMovers_TechFeasibility_CostEffectivenessAnalysis_Final_05142019.pdf.

[70] *Id*. at 5.1.2.

from certain manufacturers will not be able to meet the emission rate limits EPA has proposed. Absent a system based on source-specific emission limits, emissions averaging is one of the only practical mechanisms for addressing these challenges. Even with emissions averaging, absent additional changes to the Proposed Rule, compliance challenges will remain. Nevertheless, what is clear is that compliance without averaging will be impossible.

As the D.C. Circuit has explained, "impossibility" is a key concept under the good neighbor provision of the CAA.[71] EPA is obligated to align its interstate transport emission reduction requirements with the next applicable NAAQS attainment date unless doing so is "impossible." Just as EPA is obligated to provide sources with adequate time to achieve the emission reductions necessary to address significant contribution, EPA must provide adequate regulatory tools and safety valves to ensure that affected sources can comply with the Agency's rules.

V. EPA Has Underestimated the Length of Time Necessary to Retrofit Existing Units.

As EPA has acknowledged in past rulemakings where it has considered addressing interstate transport of ozone by including emission reduction requirements for RICE in the natural gas pipeline industry, significant time and resources are needed for acquiring control technologies, hiring the labor required for retrofits, obtaining needed permits, and managing the timing for staggering retrofits.[72] The Proposed Rule includes a compliance timeframe that cannot be reconciled with EPA's past positions and that the industry cannot meet under current conditions. INGAA's comments advocate for a number of changes to the Proposed Rule, all of

[71] *Wisconsin*, 938 F.3d at 320; *New York v. EPA*, 781 Fed. App'x 4, 7 (D.C. Cir. 2019).

[72] *See, e.g.*, U.S. EPA Office of Air and Radiation, Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance at 21; Docket ID No. EPA-HQ-OAR-2015-0500 (November 2015) (hereinafter "Non-EGU NOx Emission Controls TSD").

which would help to improve the feasibility of NOx regulation for affected units. Those changes include:

- Revising the Proposed Rule to regulate a number of units that would achieve emission reductions consistent with the level of control needed to address the significant contribution of the industry to downwind nonattainment and maintenance issues
- Preventing unlawful over-control
- Allowing the use of emissions averaging as a compliance tool for affected units
- Responsibly addressing regulatory costs and reliability impacts

Even with these changes, compliance with a well-designed and reasonable rule to address interstate transport of NOx is almost certainly impossible for the interstate natural gas pipeline industry to achieve by 2026. This section of INGAA's comments explains why that is the case and the nature of the constraints that will limit the installation or modification of controls on RICE that would be affected by the Proposed Rule. As described below, for these reasons, INGAA suggests that EPA generally consider a phased approach to compliance with any NOx standards that it promulgates for the industry.

In a 2014 analysis[73] prepared for the INGAA Foundation, Inc. and submitted to EPA as part of rulemaking docket for its 2014 CSAPR "Close-out" rule,[74] Innovative Environmental Solutions, Inc. & Optimized Technical Solutions evaluated "the resources required of the operating companies, emission reduction suppliers, engineering service providers, and contractors to implement NOx control regulations for low speed reciprocating engines used in the interstate natural gas transportation industry" and concluded that "the projected time to

[73] Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," (July 2014) ("Control Availability Report").

[74] 83 Fed. Reg. 31,915 (July 10, 2018).

implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules."[75] The report is extremely relevant to the current rulemaking. It evaluates the same emission control technologies, including Low Emission Combustion ("LEC"), nonselective catalytic reduction ("NSCR"), and selective catalytic reductions ("SCR") that continue to be the basis for the emission rates proposed by EPA to address interstate transport for the 2015 ozone NAAQS.[76] The report also contains a review of the various types and numbers of RICE inventoried at the time.[77] The report's evaluation of potential regulatory drivers includes a new regional rule to address interstate transport comparable to but more stringent than the 2004 Phase 2 NOx SIP Call, precisely what the Proposed Rule is, and it specifically considers potential impacts (including "a broad regional NOx control rule") of a 2015 ozone NAAQS set in a range from 60 to 70 parts per billion ("ppb"), accurately reflecting the current regulatory landscape.[78] It also evaluated available resources and the cost and schedule to install controls based on NOx endpoints of 3 g/bhp-hr or 1 g/hp-hr, consistent with the limits EPA has now proposed.[79]

After reviewing this fundamental information, the report provides an assessment of resource constraints associated with NOx control retrofits. In doing so, it provides relevant examples, such as the conversion of 200 natural gas transmission units to LEC starting in 1999 as part of the NOx SIP Call. The report finds "[f]rom interviews with the operators and the emission reduction equipment suppliers, the conversion process took six years in total to fully implement."[80] The report further concludes that, generally, "[b]ased on interviews with pipeline

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[75] Control Availability Report at 1.

[76] *Id*. at 6-9.

[77] *Id*. at 10-18.

[78] *Id*. at 18-19.

[79] *Id*. at 21.

[80] *Id*. at 27.

operations and emission reduction equipment suppliers having experience with previous conversion projects, NOx control for each engine requires between 1 and 2 ½ years to complete (from inception to completion of commissioning)" with older engines and retrofits requiring more infrastructure modifications taking additional time.[81] Most importantly for purposes of a broadly applicable rule like the Proposed Rule, "[t]aking into account both the lead time and conversion time and based on currently available resources (i.e., trained personnel), the average number of units that can be modified to lean combustion on a sustained basis is *approximately 75 engines per year*."[82] The report's conclusion in this regard is based on what it calls current resource availability, but it acknowledges that "a dramatic increase in market demand would likely result in hiring and training of additional resources."[83] Nevertheless, "the special skills associated with this niche market would require time to build that resource."[84]

To retrofit RICE to meet a 3 g/hp-hr standard, the report estimates that "[b]ased on current technical resources, the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules[, and] that it would take decades to address NOx controls for a large number of engines, even if the annual rate of retrofit conversions is doubled."[85] Retrofitting a smaller number of engines to achieve a 1g/hp-hr standard, the report concludes, would have a minimal impact on schedule, but would have "a significant cost impact, with engine-specific costs on average about 65% higher to achieve 1 g/hp-hr."[86]

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[81] *Id*.

[82] *Id*. (emphasis in original).

[83] *Id*.

[84] *Id*.

[85] *Id*. at 29.

[86] *Id*.

The market for expert services needed to conduct the retrofits that would be required by the Proposed Rule has not improved in any substantial way since the preparation of the Control Availability Report. EPA's own estimate that covered RICE can install controls by the 2026 ozone season is undermined by the Agency's substantial underestimation of affected units, as described in section II of these comments. For the existing equipment in natural gas transmission, there is a limit of qualified service providers that support control implementation. Factors to be considered include service provider and equipment availability (which is limited), access to multiple vendors that serve the supply chain, budget cycles and lead time for procuring equipment, consideration of control installation downtime requirements of about one month for each unit serviced, operating constraints that limit out-of-service equipment, and timing for permitting. Further, current supply chain issues affecting the economy as a whole will undoubtedly result in further delays in performing necessary retrofits.

In addition, there are permitting constraints that will significantly expand the timeframe for completing retrofits required by the Proposed Rule. Due to the workload of the permitting agencies, the permitting process typically takes six to fifteen months to complete. In some cases, the process can take longer depending on the complexity of the project. With a rule that envisions permitting requirements as broadly applicable as the Proposed Rule's, significant delays and resource constraints are likely to add additional delays to the process.

EPA's proposal also does not take into account that pipelines that choose to replace RICE units with new units must seek permitting approval from various federal agencies, including the Federal Energy Regulatory Commission ("FERC") should they either increase the hp of the unit or need to seek a new or temporary right-of-way for construction. A pipeline that wishes to increase its hp must seek a certificate of public convenience and necessity from FERC under section 7 of the Natural Gas Act. It must also obtain various environmental permits from permitting agencies, such as U.S. Army Corps of Engineers, EPA, and the Department of Interior's Fish and Wildlife Service, and submit for safety review by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration. The FERC timeline for reviewing—assuming it must go through a National Environmental Policy Act review—will take at a minimum 1 ½ years. EPA's proposal is likely to prompt a sudden, substantial increase in the number of certificate or permit applications submitted to the government for review if owners and operators determine that retrofitting affected units will require the expansion of facility footprints or if other similar action will be necessary. This increase in turn could further lengthen the review period by straining the resources of federal agencies. The review period also could take longer if the compressor is sited in a densely populated area or there are protests associated with the project.

As one measure to address potential compliance deadline bottlenecks and other complications, EPA has asked for comment on a case-by-case extension process for non-EGU sources. The Agency has asked for specific criteria by which it should judge such requests and on the process for reviewing and acting on such requests. A flexible and timely approach for addressing case-by-case compliance deadline extensions is an important backstop measure that could be of significant use to industry and permitting authorities when circumstances demand it. To that end, INGAA supports adoption of a process substantially similar to the approach used to determine RACT for individual sources. EPA could implement such a process pursuant to its FIP, but also could make clear in its final rule that states could submit simple SIPs to take over this process from EPA.

It is unclear from EPA's proposal whether the Agency envisions making these determinations itself or delegating these sorts of decisions to the states. INGAA generally supports allowing states to take over the process for making source-by-source determinations, given their experience and expertise in overseeing such determinations. EPA should make clear in any final rule that it encourages states to take such action. To assist states in taking control of these interstate transport provisions, EPA should clearly state the emission reduction targets that it believes are needed to address significant contribution. EPA should also make clear, consistent with governing case law, that states are free to determine the means used to achieve emission reductions and that states may choose alternative approaches to the emission limits EPA has proposed in its FIP.[87]

In addition, INGAA suggests that upon submittal of a complete application for a case-by-case deadline extension determination, the final rule provide for an automatic tolling of the relevant compliance date or dates that would be commensurate with the time taken by EPA (or other decisionmakers) to make a final determination regarding the extension. Such a provision would confer a necessary level of certainty for regulated sources to make effective use of any extension provision.

INGAA supports EPA adopting the most flexible process possible for making such requests, as cost, technical, or issues or other constraints could arise at any time leading up to the Proposed Rule's general compliance deadline. Accordingly, INGAA does not recommend that EPA establish a hard cutoff date for submittal of case-by-case extension requests. EPA should

[87] *Michigan v. EPA*, 213 F.3d 663, 686 (D.C. Cir. 2000), *cert. denied*, 121 S. Ct. 1225 (2001) (noting that in the NOx SIP Call "EPA calculated the budgets using highly cost-effective emission controls, [but] the agency allows the states to choose the control measures necessary to bring their emissions within the budget requirements").

judge any such request on the merits of the issues that have arisen, including whether the issues were brought to EPA's attention in a timely manner.

Even if EPA adopts a case-by-case extension provision, INGAA nevertheless believes, as stated above, that the interstate natural gas pipeline industry requires a more comprehensive and universally applicable phased compliance schedule for any rule that EPA is likely to develop. How long that phased compliance schedule will need to be will depend on the number of units that are ultimately subject to the rule and key features of the rule. INGAA is prepared to work with EPA to help design a compliance program that will be reasonable and successful. What is clear, however, is that the proposed compliance deadline in 2026 is not possible for the industry.[88]

As noted above, impossibility is a key legal standard that the courts have identified as controlling EPA's discretion to establish compliance deadlines under the good neighbor provision. Generally, EPA's interstate transport rules must include compliance deadlines for upwind states that will ensure implementation of upwind state obligations by the next applicable

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[88] EPA suggests in the Proposed Rule that affected units have been given additional notice by virtue of the Proposed Rule's availability and that this additional time further supports the 2026 compliance deadline for non-EGUs that would be subject to the Proposed Rule. 87 Fed. Reg. at 20,101 ("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"). EPA should acknowledge that owners and operators of potentially affected units cannot realistically plan for compliance with provisions of a Proposed Rule that is likely to change as a result of the rulemaking process and that the proposal of a new regulation will not alter the market constraints, permitting bottlenecks, and similar issues that will all determine the timeframe in which compliance with a final rule will be possible. As a legal matter, moreover, the courts have recognized that regulated parties must have fair notice of what will actually be required of them and the time necessary to comply. A proposed rule does not provide adequate assurance of what will ultimately be required. *See, e.g., FCC v. Fox Television Stations, Inc.*, 132 S. Ct. 2307, 2317 (2012) ("A fundamental principle in our legal system is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required."); *id*. ("regulated parties should know what is required of them so they may act accordingly"); *Christopher v. SmithKline Beecham Corp.*, 132 S. Ct. 2156, 2168 (2012) ("It is one thing to expect regulated parties to conform their conduct to an agency's interpretations once the agency announces them; it is quite another to require regulated parties to divine the agency's interpretations in advance ...."). Further, under the most generous interpretation, the publication of the Proposed Rule would provide affected units, with at most, four years and 25 days until the beginning of the ozone season in 2026. Even if this were a valid consideration, the additional time provided by virtue of publication of the Proposed Rule would not come close to addressing the constraints on compliance for the interstate natural gas pipeline industry, as these comments explain.

attainment deadline. That is the case unless it is impossible for sources to achieve those emission reductions in that timeframe. The schedule EPA has proposed for engines in the pipeline transportation of natural gas sector is impossible for the affected units to meet. As such, EPA has the authority and the obligation to establish alternative, workable compliance deadlines in the final rule.

VI. EPA Has Not Adequately Evaluated Reliability Issues.

Installation of controls and monitoring equipment will require taking affected units offline for extended periods of time. Installing controls to meet EPA's proposed schedule is certain to have serious reliability implications due to the Proposed Rule's impact on interstate natural gas pipeline companies that operate as an interconnected system. EPA has not assessed how the system will be impacted nor offered any guidance on how such a massive effort could be coordinated.

Each pipeline will need to take their affected units offline at the same time to meet EPA's compliance deadline because the time needed to complete the necessary retrofits would preclude an orderly, sequential approach. This will greatly reduce throughput throughout the nation, leading to reliability issues. This is the case because the U.S. natural gas pipeline system is a highly integrated network.[89] Thus, if throughput is reduced across the 23 states covered by the Proposed Rule, shippers in other states who depend on natural gas being transported first to those 23 states will be impacted.

For example, New England "has no indigenous fossil fuels and therefore, fuels must be delivered by pipeline, ship, truck, or barge from distant places."[90] "[A] failure at a single point

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[89] EIA, *Natural Gas Explained*, available at https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

[90] ISO-NE, Natural Gas Infrastructure Constraints, available at https://tinyurl.com/2p9ewwjc.

on the pipeline system . . . in New England will likely create significant impacts."[91] The pipelines delivering natural gas into New England run through New York and New Jersey—two states covered by the EPA's proposal. The removal of RICE units in those states could reduce capacity delivered into New England and cause significant disruptions.

Because affected pipelines will not be able to coordinate repair schedules, large volumes of capacity are likely to be reduced at the same time period as a result of the Proposed Rule. These periods will likely extend over times of "peak" demand, either during winter or summer months when natural gas utilities and electric generators (who are pipeline shippers) need natural gas service to provide heat or air conditioning for their customers. During these periods, at a minimum, pipelines operate at full capacity and need all of their compressor units available to run. Removing multiple units from service during these high demand periods will inevitably lead to reliability issues. Even during non-peak periods, reducing pipeline capacity for long periods of time will reduce pipeline throughput, preventing shippers from transporting as much gas as their users require.

Neither the Proposed Rule nor any of the technical support documents currently in the docket provide any substantive analysis of reliability issues for the interstate natural gas pipeline industry. EPA cannot reasonably evaluate the appropriateness and feasibility of the Proposed Rule without assessing potential impacts on natural gas system reliability, supplies, and price. The Proposed Rule, accordingly, lacks a reasoned basis based on the current record. To address this shortcoming, EPA must evaluate reliability and tailor its rule to prevent serious and predictable reliability problems.

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[91] *Id.*

VII. EPA Has Inappropriately Identified SCR as the Preferred Technology for Four-Stroke Lean Burn Engines.

For 4SLB engines, the Proposed Rule identifies SCR[92] as the technology basis to achieve the proposed NOx limit, while acknowledging that "layered combustion controls" (*i.e.*, typically referred to as low emissions combustion or LEC technology) may apply. While SCR application is fairly common for larger combustion sources, such as electric utilities and large industrial boilers, SCR application to RICE in the gas transmission industry is very rare. In previous RICE rulemakings, such as the spark ignition engine NSPS[93] or the NOx SIP Call Phase 2 rule, EPA clearly identified LEC technology as the preferred approach for 4SLB engines, and that technological choice still applies. For example, the Technical Support Document[94] for the NOx SIP Call and the Response to Comments[95] for that rulemaking identify LEC as the control technology for both 4SLB and 2SLB. An EPA commissioned report[96] supporting the NOx SIP Call also identifies LEC as the preferred control technology for lean burn engines. The more recent Subpart JJJJ rulemaking also based NOx standards on LEC control.

LEC is the preferred technology for natural gas operators for many reasons, including environmental, reliability, and economic reasons. Once the retrofit installation is complete, LEC technology is inherent to engine operation and requires minimal additional attention to engine operating and maintenance procedures. SCR requires considerable attention to the reagent

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[92] 87 Fed. Reg. at 20,142.

[93] 40 C.F.R. Part 60, Subpart JJJJ.

[94] "Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call" (Oct. 2003).

[95] "Response to Comments Phase II NOx SIP Call Rulemaking" (Apr. 1, 2004).

[96] "NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States," E.H. Pechan and Associates report for U.S. EPA Innovative Strategies and Economics Group (Aug. 2000) ("Pechan Report").

injection system and instrumentation that controls reagent feed rate. The pollution prevention provided by LEC (*i.e.*, emissions are not formed) is far preferrable to post-combustion exhaust control, and the operational simplicity compared to SCR ensures engine availability. While the initial capital investment *may* be marginally higher for LEC retrofit technology, ongoing operating costs are significantly lower.

The environmental performance of LEC is also superior. Similar NOx levels can be achieved with LEC and SCR, and LEC technology performance is ensured because it is inherent to engine operation, while SCR requires proper control of ammonia injection and catalyst performance. In addition to low NOx levels, LEC can provide improved efficiency (*i.e.*, lower fuel use) and lower emissions of unburned hydrocarbons due to improved in-cylinder mixing prior to ignition of the air-fuel mixture. Thus, LEC can reduce GHG, VOC, and carbon monoxide ("CO") emissions relative to an uncontrolled lean burn engine. In addition, since a reagent or chemical addition to the process is not required, LEC eliminates the negative environmental impacts of SCR—*e.g.*, ammonia emissions ("ammonia slip" past the catalyst); impacts of ammonia production and frequent delivery to the site; catalyst production, cleaning and disposal; and operational inefficiencies caused by exhaust back pressure on the engines caused by the catalyst.

This "technology choice" does not impact the NOx emission standard proposed, but EPA should ensure that the record in the final rule clearly indicates LEC is the preferred control technology for 4SLB engines.

VIII. Assumed NOx Control Efficiencies Are Inaccurate and Not Consistent with Past EPA Decisions.

The natural gas transmission reciprocating engines affected by the Proposed Rule are similar in key respects to the units regulated in the NOx SIP Call Phase 2 rule. In that action, EPA focused on the very largest units (*i.e.*, those with ozone season emissions above 1 ton per day, which is equivalent to 365 TPY). As discussed above, in this rulemaking, EPA initially identified units in the affected states with emissions above 100 TPY and then incorrectly equated that to a 1,000 hp uncontrolled engine. The gas transmission reciprocating engines affected by the Proposed Rule are, therefore, the same industrial class and type of equipment regulated by the NOx SIP Call Phase 2 rule, but with a much lower applicability threshold. Since the NOx SIP Call Phase 2 rulemaking, additional units have been controlled or otherwise reduced emissions due to state RACT rules or system upgrades (*e.g.*, hp replacement with a turbine), but the technical facts and science relevant for the NOx SIP Call Phase 2 rule still apply today.

In the previous rulemaking, EPA analysis led to conclusions regarding baseline uncontrolled emissions, applicable control technologies (*e.g.*, LEC for lean burn engines and NSCR for rich burn engines), and average reductions from control. For example, EPA determined that the majority of affected units were 2SLB engines, and an EPA report[97] concluded, on average, that baseline emissions were 16.8 g/bhp-hr and that LEC would achieve 82 percent average control with an endpoint just under 3 g/bhp-hr. The "layered combustion technology" referred to in the Proposed Rule preamble is a new EPA moniker for LEC control, and that technology is discussed in detail in the EPA report noted above. The technology basis and emission standard for 2SLB evaluated in the 2000 Pechan Report are consistent with the NOx standard for 2SLB units in the Proposed Rule as well as EPA's emission standard for reconstructed or modified units (*i.e.*, units requiring retrofit) in Subpart JJJJ.[98]

[97] *See* Pechan Report, *supra* footnote 95.

[98] 40 C.F.R. § 60.4233(f)(4).

However, the docket document summarizing EPA reduction estimates includes much higher control levels than those EPA previously determined to be realistic. For 2SLB units with LEC, EPA now typically applies 97 percent reduction. From the baseline in the previous EPA report, this equates to an emission rate of 0.5 g/bhp-hr. While this may be acceptable as the level achievable for a new lean burn engine, it is not an accurate representation of the average emission level achievable for existing units. Similarly, EPA estimates over 95 percent reduction for NSCR on rich burn engines, which equates to an endpoint less than 0.5 g/bhp-hr. EPA notes that it has reviewed results within this range for all engine types,[99] but this assertion does not adequately justify EPA's departure from the Agency's well-documented conclusions in the EPA NOx SIP Call Phase 2 rule docket.

As discussed in comments above regarding EPA's significant underestimate of unit counts and estimated reductions, INGAA welcomes additional analysis to better define the emissions budget and reductions contained in the Proposed Rule. Additional time would be needed for EPA to prepare and the public to assess such information, and INGAA offers its assistance in those efforts. In the absence of additional detailed analysis, however, EPA should re-evaluate the emissions control levels assigned to affected gas transmission RICE because EPA did not assign accurate emission control level to those units.

IX. EPA Properly Proposed Parameter Monitoring for Compliance Assurance for Natural Gas Transmission Reciprocating Engines.

For LEC-equipped lean burn reciprocating engines, EPA proposes continuous parameter monitoring[100] systems ("CPMS") for compliance assurance. INGAA supports EPA's proposed monitoring approach for compliance assurance of natural gas transmission reciprocating engines.

[99] 87 Fed. Reg. at 20,142, Table VII.C–1.

[100] *Id*. at 20,177; 40 C.F.R. § 52.41(d)(4).

INGAA recommends minor changes to the requirements for catalyst equipped engines (*e.g.*, 4SRB engines using NSCR). Additional details regarding parameter monitoring follows. In addition, information is provided to support EPA's decision not to require continuous emissions monitoring systems ("CEMS") for gas transmission reciprocating engines.

A. Parameter Monitoring for LEC-equipped Lean Burn Engines

As discussed in section VII, LEC is the preferred NOx control for all lean burn engines. Once installed, LEC technology is inherent to engine operation and the combustion controls cannot be "turned off" or bypassed. Compliant emissions are ensured by proper operation of the combustion process, and basic operating parameters can be monitored to ensure combustion health. The Proposed Rule requires a site-specific monitoring plan for LEC engine CPMS. A brief overview of example parameters to monitor is discussed here based on permit conditions for LEC monitoring at existing major source facilities (*e.g.*, to address compliance with state RACT requirements).

The majority of affected transmission reciprocating engines are 2SLB units, and combustion-based emission controls will include adding additional air (to lower temperatures and decrease NOx), higher energy ignition to ensure the lean mixture is ignited, and/or higher-pressure fuel injection to improve the uniformity of the in-cylinder mixture and enhance combustion stability. Combustion performance is ensured by monitoring parameters that indicate operation within expected norms, including fuel use, air manifold pressure, and air manifold temperature. The parameters, measurement specifications, and accepted operating range would be provided in the monitoring plan, and similar plans will be utilized for all 2SLB engines in a company fleet.

B. Parameter Monitoring for Rich Burn Engines

For 4SRB engine parameter monitoring, the Proposed Rule includes continuous monitoring of catalyst inlet temperature and monthly monitoring of catalysis pressure drop ("ΔP"). Section 52.41(d)(3)(ii) of the Proposed Rule requires ΔP monitoring monthly, with maintenance required "if the pressure drop is greater than 2 inches outside the baseline value established after each semiannual portable analyzer monitoring." The criteria are similar to RICE national emission standards for hazardous air pollutants ("NESHAP") monitoring requirements for 4SRB engines with NSCR but fail to acknowledge an important operational constraint—ΔP can vary from month to month due to the operating load of the engine because exhaust flows change with load. Thus, rather than requiring the operator to compare the monthly reading to the "baseline value established after each semiannual portable analyzer monitoring," the operator should be allowed to compare the ΔP to the value measured during any previous emissions test conducted at a similar load and then assess whether action is warranted. The operator can maintain records to document any instance where monthly ΔP monitoring warrants review or follow-up, including documentation of maintenance or other action conducted when deemed necessary.

This issue is discussed and explained in detail in INGAA comments[101] on the 2002 RICE NESHAP proposal, including documentation of how ΔP can vary with operating load. The RICE NESHAP approach to conduct ΔP at "full load" and compare to the value from a "full load" performance test is not recommended, because that load may not be achievable month-to-month. In addition, the proposed requirement to compare with the most recent performance test is not desirable because the biannual test may not always be possible at full load. Thus, INGAA recommends that monthly ΔP monitoring assess the measured value relative to a change greater than 2 inches from a

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[101] INGAA Comments on Proposed RICE NESHAP, Docket ID No. OAR-2002-0059 (Feb. 19, 2003).

previously measured value associated with a performance test at a similar load. The operator can maintain records of the measurement and review of actions taken whenever the value by more than 2 inches (of water column) from the value measured in a previous test at similar load, rather than the most recent performance test.

C. CEMS are Not Warranted for Natural Gas Transmission Reciprocating Engines.

EPA has considered CEMS for natural gas transmission compressor drivers in past rulemakings and consistently concluded that CEMS are not warranted due to costs and the availability of other established methods for compliance assurance. This technical basis still stands, and CEMS are not warranted.

EPA contemplated NOx CEMS during combustion turbine NSPS review in 2005. The preamble to proposed Subpart KKKK indicates that NOx CEMS were considered as a monitoring requirement for the proposal, but EPA concluded that CEMS costs are too high relative to a reliable alternative—annual stack testing and/or parameter monitoring. INGAA supports the EPA conclusion regarding the excessive costs of CEMS (without commensurate benefit), and also supports the conclusion that a periodic source test provides a reliable basis for demonstrating compliance with the NSPS standard. Parameter monitoring is provided as an alternative to testing in Subpart KKKK.

Analysis of CEMS costs is presented in a docket memorandum (Docket Document No. OAR-2004-0490-0115). The docket document and the preamble conclusions regarding CEMS are further supported by:

- CEMS cost analysis for other reciprocating engines rules that indicate costs similar to or higher than the cost projection for Subpart KKKK.
- Recent precedent from NSPS and maximum achievable control technology (“MACT”) standards regarding monitoring requirements and the exclusion of CEM requirements.

In addition to the cost analysis in the Subpart KKKK docket, other EPA rulemakings included the consideration of the costs of CO CEMS for MACT standards. Note that CO CEMS costs are comparable to NOx CEMS costs, with a NOx unit likely to be marginally more costly due to higher instrumentation and operating costs for a NOx analyzer. Examples of regulations that considered CEMS include the Turbine NESHAP, Engine Test Cell NESHAP, Reciprocating Internal Combustion Engine NESHAP, Petroleum Refinery NESHAP, Mineral Wool NESHAP, and Hospital/Medical/Infectious Waste Incinerator NESHAP. For these standards, analysis indicated CEMS costs similar to or higher than the estimate for Subpart KKKK. In each case, costs were considered excessive and CEMS were not required. These decisions are relevant because they provide an indication of consistency in EPA's justification of monitoring requirements and demonstrate the environmental burdens associated with the sources and regulations that did not require CEMS under Part 63. For example, the environmental implications of the Waste Incineration MACT invoke a higher level of concern and are associated with a higher probability of emissions performance variability than reciprocating engine NOx emissions.

In addition, the efficacy of reciprocating engine LEC supports an approach based on parameter monitoring and periodic testing. As opposed to add-on emission control technologies where performance can be dramatically affected by short term deviations in a key process parameter (*e.g.*, ammonia feed rate for SCR), LEC is a pollution prevention approach with the NOx control inherent to the design and operation of the engine. The control technology cannot be "turned on or off" by the operator and emissions performance is inherent to the operation and functionality of the unit. A periodic test provides assurance that minor changes or upward trending of NOx emissions that may occur over longer time periods due to equipment wear will be monitored and addressed. Because of the performance of LEC combustion technology and the viability of periodic source tests and parameter monitoring, implementation of CEMS cannot realize an incremental benefit in ensuring performance commensurate with the CEMS costs.

The proposed RICE NESHAP (Part 63, Subpart ZZZZ) considered CEMS for CO for lean-burn engines greater than 5,000 hp to demonstrate compliance with the CO percent reduction standards. For lean burn engines less than 5,000 hp, EPA proposed periodic stack testing and continuous monitoring of operating parameters. For that standard, EPA ultimately concluded that CEMS were not warranted and parameter monitoring and periodic tests assured compliance.

CO CEMS costs were included for both the RICE NESHAP and the Engine Test Cell NESHAP, with estimated costs slightly higher in the latter. Very little detail was provided to understand how the different costs were derived, but costs were likely based on the EPA CEMS Cost Model. For the Engine Test Cell NESHAP MACT, a docket memorandum (Item II-B-9 of Air Docket A-98-29) indicates that the costs were determined using EPA's CEMS Cost Model Version 3.0, updated in 1998. The projected costs (20 years ago) include an estimated initial cost of $232,400, with an estimated annual cost of $69,000.

EPA considered the cost differential between CEMS and approaches based on parameter monitoring with periodic tests in several NESHAPs—and selected parameter monitoring as a reasonable approach. Many examples are available where EPA concluded CEMS were not warranted and other compliance assurance measures were available (*i.e.*, parameter monitoring and/or testing). Other examples include the Petroleum Refineries NESHAP for catalytic cracking units, the Mineral Wool NESHAP, and the Hospital/Medical/Infectious Waste Incinerator NESHAP. EPA consistently concluded that parameter monitoring and/or periodic tests provided compliance assurance.

In addition, there is no evidence in the Proposed Rule docket to suggest that CEMS would provide any appreciable emissions control improvement as compared to parameter monitoring and periodic tests. Lacking any such evidence, it is clear that parameter monitoring and periodic tests provide compliance assurance, and CEMS are not warranted.

X. EPA Has Proposed Unnecessary Assurance and Compliance Provisions.

A. The Proposed Rule Should Be Amended to Clearly Identify Accepted Methods for NOx Emission Tests.

The Proposed Rule would require biannual emissions tests for affected RICE, and section 52.41(d)(2)(iii) cites federal code for identifying applicable test methods. To avoid confusion and ensure appropriate methods are clearly allowed, INGAA recommends amending this section to add a direct citation of applicable NOx methods and approved alternatives for units subject to EPA's NSPS for spark-ignited RICE, 40 C.F.R., Part 60, Subpart JJJJ. For NOx measurement, this includes:

- Method 7E of 40 CFR part 60, appendix A-4
- ASTM Method D6522
- Method 320 of 40 CFR part 63, appendix A
- ASTM Method D6348
- ALT 138,[102] which allows the use of OTM-39[103] as an alternative to ASTM Method D6522
- CTM-022, CTM-030, CTM-034

[102] Letter from Steffan M. Johnson, Leader, EPA Measurement Technology Group to Wendy Coulson (Aug. 25, 2020), available at https://www.epa.gov/sites/default/files/2020-08/documents/prci_08_24_2020_signed.pdf.

[103] OTM-39 Method for Determination of Oxygen, Carbon Monoxide and Nitrogen Oxides from Stationary Sources using Portable Gas Analyzers Equipped with Electrochemical Sensors, available at https://www.epa.gov/sites/default/files/2020-08/documents/otm-39_performance_method_using_portable_gas_analyzers_08_24_2020.pdf.

Amending the Proposed Rule to include this list of accepted NOx test methods will improve clarity and ensure the federally approved list of RICE test methods can be used for periodic tests. The Proposed Rule should make clear, moreover, that owners and operators of affected units are free to choose from among these various options.

B. The Proposed Performance Testing and Reporting Requirements Are Overly Burdensome.

The Proposed Rule would require semi-annual performance testing for units that do not meet the certification requirements of section 60.4243(a). Proposed section 52.41(d)(2) would require new engines to conduct an initial performance test within six months of engine startup and subsequent tests every six months thereafter. Existing engines would be required to conduct an initial performance test within six months of becoming subject to an emission limit under the Proposed Rule and would have to conduct subsequent tests every six months thereafter. Similarly, the Proposed Rule would require semi-annual reporting of data generated by the required performance testing.

Because the Proposed Rule is intended to address emissions during the ozone season, which runs from May 1 to September 30 of each calendar year, a single performance test and report per year should be sufficient to demonstrate compliance. Limiting performance testing and reporting to an annual requirement would also provide significant cost savings.

This would be a practical measure for a number of reasons. For instance, a significant number of the units that would be subject to the Proposed Rule would also be regulated pursuant to the NSPS for stationary spark ignition internal combustion engines in 40 C.F.R. Part 60, Subpart JJJJ. Those tests are conducted on an annual basis, and EPA should not layer additional, contrary requirements on Subpart JJJJ sources through the Proposed Rule.

Further, for many units, semi-annual testing would be impractical. For example, semi-annual testing for compressors located at storage facilities that are used both for storage and transmission operations is unnecessary and infeasible. Those units, which would be covered by the Proposed Rule, are used to inject gas into storage fields when it is purchased in the summer and pumped into transmission pipelines based upon market demands in the fall and winter. During the summer, when gas is purchased and injected, compressor capacity can be controlled and maintained at 90 percent, as required for conducting a reliable emissions test. During fall and winter withdrawals, however, that capacity cannot be maintained, preventing a meaningful stack test. Accordingly, EPA should eliminate semi-annual testing.

The Proposed Rule would also rely exclusively on electronic submittal of performance testing. EPA should allow owners and operators alternative means of submitting required reports. The Agency should also allow submittal in hard copy form where that approach is required by the relevant state authority.

INGAA requests that EPA consider amending these proposed requirements.

XI. Issues Related to States EPA Has Identified as Linked to Downwind Nonattainment or Interference with Maintenance for Emissions from Non-EGUs.

If EPA were to pursue adding additional states to the non-EGU Good Neighbor Plan region, the Agency would be required to first propose such action and provide a sufficient record basis to support such action. The requirement that agencies provide notice and an opportunity for comment on a proposed rule is a basic hallmark of administrative law that is grounded in the constitutional right to due process. As long recognized by the courts, the purpose of adequate notice in the rulemaking process is to "provide an accurate picture of the reasoning that has led the agency to the proposed rule," and to allow interested parties to contest that rulemaking if they see fit.[104] Any decision to expand the scope of the Proposed Rule to include additional states or sources is substantial enough to fundamentally alter the premises of the proposal and to require additional notice to adequately inform potentially interested parties.[105] Accordingly, INGAA requests that EPA ensure that any significant change in course from the terms of the Proposed Rule be noticed through a supplemental proposal.

XII. The Proposed Rule Contains Regulatory Language that Should Be Modified.

The regulatory language that EPA has published includes provisions that are ambiguous, contain clerical errors, or that otherwise should be clarified to avoid unnecessary confusion. This section of INGAA's comments identifies those provisions and suggests appropriate revisions for EPA's consideration.

The definition of "affected unit" should be amended to make clear that emergency engines are not included in the Proposed Rule's requirements. As a policy matter, the vast majority of emergency engines are not likely to have emissions in significant amounts due to their limited hours of operation, and are, therefore, regulated pursuant to other, more appropriate programs. Furthermore, due to the limited hours of operation, it is extremely unlikely that additional controls on emergency engines over the hp threshold are economically feasible, based on the marginal cost threshold of up to $7,500 per ton referenced in the Proposed Rule. Clarifying the definition of affected unit to address this issue would avoid unnecessary confusion on behalf of potentially affected owners and operators.

[104] *Connecticut Light & Power Co. v. Nuclear Regulatory Commissions*, 673 F.2d 525, 530 (D.C. Cir.), *cert. denied*, 459 U.S. 835 (1982).

[105] *See City of Waukesha v. EPA*, 320 F.3D 228, 245-47 (D.C. Cir. 2003) (explaining that final rule must be "logical outgrowth" of the agency's proposed rule).

The applicability section of the Proposed Rule should be amended to address several issues. First, the provision states that the Proposed Rule's requirements apply to states "listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s)."[106] The cross-reference should be to § 52.40(b)(2).

Second, similar to recent NSPS on pipeline transportation for compressor stations, *i.e.*, NSPS Subpart OOOOa, the applicability section of the Proposed Rule should be amended to include only those activities at an LNG facility that meet the intent of the included industrial source type "Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas." Based on the definition in the Proposed Rule for "Pipeline transportation of natural gas," only the portion of an LNG facility directly related to the pipeline transportation of natural gas, *i.e.*, the "compressor station" of the LNG facility, would be subject to the Proposed Rule.

The provisions specified in proposed section 52.41(c)(1)-(3), specifying emission limits, should be revised as follows:

> (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~~ then you must meet a nitrogen oxides (NOx) emissions ~~limits~~ limit 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~~ then you must meet a NOx emissions ~~limits~~ limit of 1.5 g/hphr.
>
> (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~~ then you must meet a NOx emissions ~~limits~~ limit of 3.0 g/hp-hr.[107]

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[106] 87 Fed. Reg. at 20,177.

[107] *See id.*

In proposed section 52.41(d)(1), the cross-reference to paragraph (b) should be paragraph (c).[108]

In proposed section 52.41(d)(2)(B), the cross-reference to paragraph (b) should be paragraph (c).[109]

The requirement stated in proposed section 52.41(d)(4)—"(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)"—is unclear and should be revised.[110]

XIII. Conclusion

INGAA and its members appreciate this opportunity to provide EPA with comments on its proposed Good Neighbor Plan for the 2015 Ozone NAAQS. As these comments demonstrate, the Proposed Rue's requirements for the pipeline transportation of natural gas sector are based on seriously flawed data and assumptions about the industry. The misinformation in the record has resulted in estimates of affected units and projections of emission reductions under the Proposed Rule that bear little resemblance to reality and, if implemented, would not appropriately address significant contribution to downwind nonattainment or maintenance issues. On the contrary, the Proposed Rule would lead to significant over-control and risk the reliability of the nation's natural gas supply, while imposing costs and other burdens that EPA has not considered. Accordingly, INGAA requests that EPA reevaluate it proposed requirements for the pipeline transportation of natural gas sector, and that the Agency engage with INGAA and its members to develop a rule that will lawfully and more effectively address emissions from natural gas

[108] *See id.*

[109] *See id.*

[110] *See id.*

pipeline facilities. INGAA further suggests that EPA consider withdrawing the Proposed Rule or issuing a supplemental proposal to address the issues raised in these comments. INGAA looks forward to providing the Agency with additional information and support.

Sincerely,

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Re: Docket ID No. EPA-HQ-OAR-2021-0668: Kinder Morgan, Inc.'s Comments on the United States Environmental Protection Agency's Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

Ladies and Gentlemen:

Kinder Morgan, Inc. ("Kinder Morgan," the "Company," or "we"), on behalf of itself and its subsidiaries and affiliates, submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA") proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (the "Proposed Rule").[1]

Kinder Morgan operates in 14 of the 23 states that would be impacted by the Proposed Rule. As a result, the Proposed Rule would directly and significantly impact the Company and could impact the end users that the Company serves. Kinder Morgan has a long-standing record of being a collaborative and cooperative stakeholder with EPA on implementation of regulations and initiatives related to the oil and natural gas sector, including with respect to the Greenhouse Gas Reporting Program ("GHGRP"), the Natural Gas STAR program, prior New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP"), as well as relevant state proposals (including but not limited to Colorado, New Mexico, and Illinois) addressing emissions limits for larger engines. With this experience in mind, Kinder Morgan requests that EPA carefully consider its comments provided here. In this comment

[1] See Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036–216 (Apr. 6, 2022).

letter, we address EPA's proposal to establish emissions limits for certain "non-Electric Generating Units" ("non-EGUs"), in particular, for those operating in the Pipeline Transportation of Natural Gas sector. Specifically, Kinder Morgan addresses EPA's proposed emissions limits for stationary, natural gas-fired, spark ignited reciprocating internal combustion engines ("RICE") with a maximum rated capacity of 1,000 horsepower ("hp") or greater (collectively, "Engines") (the "Engine Proposal").[2]

Several trade organizations have submitted extensive comments in response to the Proposed Rule. Kinder Morgan endorses the comments of the Interstate Natural Gas Association of America ("INGAA"), the Gas Processors Association ("GPA"), the Texas Pipeline Association ("TPA"), and the joint comments of the Association of Electric Companies of Texas, BCCA Appeal Group, Texas Chemical Council, and Texas Oil & Gas Association ("Texas Transport Working Group").[3] The Texas Transport Working Group, in particular, presents persuasive technical analysis on modeling flaws that run through EPA's analysis in support of its Proposed Rule. Kinder Morgan also appreciates the opportunity to comment separately on certain elements of the Proposed Rule.

I. EXECUTIVE SUMMARY

EPA's Proposed Rule is extensive, with a variety of proposals that impact multiple industries. Kinder Morgan focuses its comments on the Engine Proposal where EPA is proposing to establish stringent emissions limits for certain large engines operated across 23 states within the Pipeline Transportation of Natural Gas industry (summarized in further detail in Section III.A, below). Kinder Morgan recognizes the importance of continued emissions reductions, and the Company supports reasonable regulation that considers both technical feasibility and cost-effectiveness. As one of the largest energy infrastructure companies in North America, Kinder Morgan provides a unique and important perspective on the technical and cost impacts of adopting stringent NO_x emissions thresholds, especially in the transmission segment of the oil and gas industry. The Company has significant experience deploying various technologies to achieve cost-effective emissions reductions, and we have gained important knowledge regarding the limitations of certain technologies as applied to certain engines. The Company shares its experiences in this comment letter. While we submit these comments, supported by detailed technical and cost analyses, the Company requests that EPA engage in dialogue with Kinder Morgan and other stakeholders to work through the complexities of the Proposed Rule.

Kinder Morgan recognizes the importance of clean air and of the mandates of the Clean Air Act ("CAA"). Nevertheless, Kinder Morgan respectfully notes that EPA's Engine Proposal has many significant legal and factual shortcomings and EPA cannot move forward with the rule as proposed. The Engine Proposal is based on materially inaccurate data, resulting in erroneous

[2] See id. at 20,142–143.
[3] For the avoidance of doubt, Kinder Morgan's endorsement of the INGAA, GPA, TPA, and Texas Transport Working Group comments includes all content, attachments, exhibits, citations, and documents associated with such submissions.

and consequential conclusions that are inconsistent with both good policy and with the CAA's Good Neighbor Provision. It is unclear how EPA could make the necessary findings for a final rule given the inaccurate data it relies upon. Should EPA choose to move forward with a version of the Engine Proposal, the agency must develop the proposal based on updated and accurate data; republish a proposed rule and supporting technical papers, including with respect to target and anticipated emissions reductions; and provide a renewed opportunity for public comment on the draft rule. A failure to do so would be directly contrary to EPA's obligations to the public for rulemaking under both the CAA[4] and the Administrative Procedures Act.[5] Here, EPA has not provided the requisite data from which it proposes to base its regulation.

The Engine Proposal is inadequate and contrary to law for several important reasons.

1. EPA is relying on an inaccurate set of data in support of the Engine Proposal. In particular, according to EPA, only 77 of Kinder Morgan's Engines would be affected by the Engine Proposal. Further, this count of 77 includes 20 turbines, which are explicitly not subject to the Engine Proposal. Consequently, EPA's proposal assumes that only 57 of Kinder Morgan's Engines are subject to the Engine Proposal. In stark contrast to that number—and calling into significant doubt EPA's underlying data—Kinder Morgan's records show that approximately 950 of its Engines would be affected by the Engine Proposal. Therefore, EPA has underestimated the impacts to Kinder Morgan by more than a factor of 16. EPA has also underestimated the impacts to the sector more broadly, as summarized in more detail in the INGAA comments, which show that the Proposed Rule would require costly modifications to nearly *five* times more units than EPA had estimated.[6] Using such inaccurate and under-representative data provides an inadequate basis for reasoned decision making and results in over-control. In brief, the agency has materially underestimated the number of subject Engines, thereby underestimating the anticipated emissions by nearly half. A proposal of this nature that is built on inaccurate data is simply unreasonable; EPA must re-publish a new proposed draft rule based on an accurate factual basis before pursuing any version of the Engine Proposal.

2. EPA also underestimates concerns around the technical feasibility involved with the proposed emissions limits. Plainly stated, it is not technically feasible to achieve the proposed emissions limits in all cases. The technologies available are limited when applied to certain type of engines, and even after exhausting layered technologies, the emissions limits may not be achievable. Any final rule must account for this, and EPA's proposal fails to do so.

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[4] See 42 U.S.C. § 7607(d)(3) (setting forth requirements under the CAA for rulemaking in this context, among others, including the requirement that EPA identify the factual data it relies on).
[5] See 5 U.S.C. § 706(2)(A) (requiring reasoned decision-making); Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983) (same).
[6] See INGAA comments, Section II and Table 2 showing INGAA's count of its members units needing controls is 1,199, along with another 180 units that include emissions controls but would need additional controls. By contrast, EPA has undercounted the number at 307.

3. Assuming a given technology (or technologies) is technically feasible, achieving the standard could nonetheless be cost-prohibitive. In fact, the cost to Kinder Morgan alone to implement the Engine Proposal would be approximately, and on average, **$4.3 million per Engine** without the reasonable modifications Kinder Morgan proposes. In fact, Kinder Morgan's costs alone exceed EPA's estimated cost of implementation *for the entire Pipeline Transportation of Natural Gas sector to implement the Engine Proposal*. Furthermore, based on site-specific studies of Engines operated by Kinder Morgan (discussed in further detail below), we are seeing the cost-per-ton of NO_x reduced in excess of $500,000 in some circumstances, which far exceeds EPA's own proposed cost threshold of $7,500 per ton of NO_x reduced. The costs are largely driven by the fact that control technologies are limited, and where they are feasible, it is no small task to address after-market retrofit technologies on these Engines. When considering that Kinder Morgan alone operates approximately 950 Engines that would be subject to the Engine Proposal—and the majority would require retrofitting to meet the proposal—it is clear that the actual costs of the Proposed Rule were not accurately accounted for and considered.

4. EPA has not fully contemplated other foundationally important considerations necessary to make a final rule successful. For example, EPA fails to consider that the proposed timeline for compliance is unreasonable, if not impossible. Based on its significant and real-world experience of deploying NO_x emissions reduction technologies on large engines, Kinder Morgan can say with confidence that it would likely take at least **until 2045** to implement the Engine Proposal across all of its Engines that currently exceed the proposed emissions limits. In discussions with manufacturers—of which (to our knowledge) there are only two that can manage certain of the Company's (and others') units—Kinder Morgan's understanding is that manufacturers would only be able to address twenty to twenty-five of Kinder Morgan's units per year that exceed the proposed thresholds. This rate assumes that manufacturers expand their capacity to work on other companies' Engines as well. Simply put, the proposed 2026 compliance year is unrealistic.

5. EPA requests comment on whether NO_x controls would be operated seasonally. Once NO_x controls are installed for the ozone season, they cannot be uninstalled or simply turned off. Rather, they will become an integral part of each Engine and would be employed throughout the year and not on a seasonal basis. To the extent EPA's cost analyses reduced its cost assumptions based on seasonal use of NO_x controls, such an approach is unrealistic and must be revised.

6. EPA has not proposed an exemption for Engines used only in emergencies, which is inconsistent with other relevant federal and state engine rules.

7. The Engine Proposal includes a semi-annual testing requirement that is onerous, unnecessary, and does not consider the need for the Pipeline Transportation sector of the Natural Gas Industry to keep natural gas flowing throughout the country for the benefit of

the end users. To ease these burdens, while still ensuring adequate performance testing frequency and monitoring, Kinder Morgan suggests an alternative approach whereby testing frequency depends in part on past testing performance of a particular Engine.

To address the deficiencies in the Engine Proposal, Kinder Morgan respectfully recommends that EPA re-publish a proposed rule—supported by updated and accurate data—that would serve as a model rule that individual states can adopt as a part of their SIPs in furtherance of EPA's goals. To be clear, the model rule would only be a model, and states should still be afforded the flexibility to take another approach—so long as the resulting emissions reductions are sufficient. EPA's model rule should include the following core elements (1) an emissions averaging program to allow averaging across an operator's[7] fleet of Engines to offer flexibility in implementation to address cost, technical, and other constraints; (2) a site-specific Reasonable Available Control Technology ("RACT") analysis to address those individual circumstances where achieving the emissions limits is not cost-effective; (3) an exemption for emergency Engines; and (4) refined performance testing requirements. As Kinder Morgan explains in these comments, averaging allows regulated entities to leverage their operational expertise to achieve significant emissions reductions at the lowest cost and through the most technically feasible approach. Installing additional controls for certain types of Engines could be prohibitively expensive, even with averaging. To address this reality, the model rule must also include the option for owners and operators to show—on an Engine-by-Engine basis—that attaining the specific emissions limit would be economically infeasible. Such an option for individualized determination of economic infeasibility is critically important to accommodate circumstances in which a particular Engine cannot meet the emissions standards of the Proposed Rule due to unit- and/or site-specific considerations, and this option would operate in addition to (and before) any emissions averaging. If the Proposed Rule is not modified to provide a more flexible and cost-effective approach, the natural gas supply chain faces a threat of shortages and constrained deliveries, and an increase in the price of transportation in some circumstances that may ultimately flow through to consumers.

Kinder Morgan provides these comments in the interest of arriving at a reasonable and feasible solution in response to EPA's obligation to address ozone transport. Kinder Morgan is proposing an alternative approach that would result in a feasible, cost-effective, and workable final rule. Again, the Company invites engagement with EPA on these highly technical issues, and respectfully requests EPA re-publish a new *draft* rule adopting the Company's proposed alternative approach for the reasons discussed throughout these comments.

II. BACKGROUND: KINDER MORGAN, INC.

Kinder Morgan is one of the largest energy infrastructure companies in North America and, more specifically, one of the largest natural gas transporters and natural gas storage operators in North America. Kinder Morgan has interests in approximately 70,000 miles of natural gas

[7] By "operator," Kinder Morgan means a parent company together with any of its subsidiaries. Allowing averaging at the parent-company level increases flexibility, which in turn fosters cost-effective emissions solutions.

pipelines and owns approximately 700 billion cubic feet of working capacity of underground natural gas storage. The Company operates within 44 states in the Lower 48, with natural gas operations in 38 states. In fact, Kinder Morgan's natural gas pipelines are connected to every important natural gas resource play in the Lower 48, including the Bakken, Eagle Ford, Marcellus, Permian, Utica, Uinta, Haynesville, Fayetteville, Barnett, Mississippi Lime, and Woodford, all of which will play a significant role in meeting the nation's long-term natural gas supply. Approximately 40% of the natural gas consumed in the United States is transported by Kinder Morgan's pipelines. Key Kinder Morgan natural gas pipeline assets include Natural Gas Pipeline Company of America (which serves the high-demand Chicago market); Tennessee Gas Pipeline (which serves New York City and Boston); Southern Natural Gas (which serves the southeastern United States); intrastate pipelines in Texas (Texas is the largest producer and consumer of natural gas in the United States); El Paso Natural Gas, Mojave Pipeline, and Ruby Pipeline (which serve Southwestern and California markets).

Prioritizing the protection of public health, safety, welfare, and the environment has always been a priority for Kinder Morgan and is consistent with the Company's Vision and Mission statements. In particular, Kinder Morgan has been a leader and cooperative ally in state-level rulemakings to develop technically feasible and cost-effective programs that develop reasonable NO_x emissions limits for certain larger engines, while ensuring operations are not disrupted and operators are afforded the necessary flexibility to implement appropriate control technologies. For example, in Colorado, Kinder Morgan worked with the Colorado Air Pollution Control Division and other stakeholders during the 2019 rulemaking process on Colorado's unique "company-wide plan" approach to NO_x emissions reductions for engines over 1,000 hp. In New Mexico, Kinder Morgan was the primary transmission operator that worked closely with the New Mexico Environment Department and other industry members in 2021. In that rulemaking, the Company produced significant information and data to help inform reasonable emissions thresholds together with the options for alternative compliance plans and alternative emission standards in instances where the thresholds may be technically infeasible or not cost-effective. As a result of the expanse of Kinder Morgan's operations and its active involvement in this area, Kinder Morgan is well-versed in the complexities and challenges of cost-effectively reducing emissions from Engines, which are integral pieces of equipment necessary to ensure natural gas is delivered efficiently and safely to customers, the city gates, and homes alike. Importantly, in response to the Colorado and New Mexico rulemakings, as well as similar rulemakings in Arizona and Pennsylvania, Kinder Morgan has implemented or is in the process of implementing modifications to Engines that will achieve over 7,000 tons per year ("tpy") in total NO_x reductions.[8]

Further, to the Company's commitment to sustainable operations, Kinder Morgan is a founding member of ONE Future, a unique coalition made up of members across the natural gas industry focused on identifying policy and technical solutions that result in improvements in the

[8] With regard to Colorado, as of May 1, 2022, Kinder Morgan has achieved reductions of 564.2 tpy of NO_x, and once the plan is fully implemented, the Company's potential to emit will be reduced by 3,000 tpy of NO_x. Kinder Morgan is projected to achieve reductions of 935 tpy of NO_x in Arizona, 2330 tpy of NO_x in New Mexico, and 742 tpy of NO_x in Pennsylvania.

management of emissions associated with the production, gathering, processing, transmission, and distribution of natural gas. Members of ONE Future are committed to continuously improving their emissions management to achieve voluntary reductions in emissions and to assure efficient increased use of natural gas. ONE Future's goal is to enhance the energy delivery efficiency of the natural gas supply chain by limiting energy waste and achieving a total methane emission rate of less than one percent of gross natural gas production, well below current estimates for fugitive emissions in the sector. The ONE Future coalition represents the entire natural gas value chain, with members from some of the largest natural gas production, gathering, processing, transmission, and distribution companies in the United States.

In connection with Kinder Morgan's membership in ONE Future, it joined EPA's Methane Challenge program in 2016. As part of this program, Kinder Morgan committed to achieving a methane emission intensity[9] target of 0.31% by 2025.[10] In 2020, Kinder Morgan achieved an emission intensity of 0.04%.[11] Surpassing the 0.31% intensity target by such a wide margin reflects the depth of the Company's commitment to reducing emissions from its operations. For the period 2018 to 2020, Kinder Morgan achieved voluntary reductions in carbon dioxide equivalent emissions of 6.7 million metric tons and voluntary reductions in methane emissions of 14.2 billion cubic feet, resulting in an estimated $46 million in natural gas saved.[12]

III. BACKGROUND: EPA'S PROPOSED ENGINE EMISSIONS STANDARDS

A. Summary of EPA's Proposed Emissions Standards for the Pipeline Transportation of Natural Gas Sector.

As part of the Proposed Rule, EPA is proposing to establish emissions limits for certain industrial stationary sources referred to as non-EGUs in 23 states. All subject Engines would have to meet the emission limits by 2026. Based on the results of its Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 ("Non-EGU Screening Assessment Memorandum"), EPA identified emissions unit types in seven industries that it believes "provide opportunities for NO_x emissions reductions that result in meaningful impacts on air quality at the downwind receptors."[13] Of relevance to Kinder Morgan is the Engine Proposal portion of the Proposed Rule, which would apply to the Pipeline Transportation of Natural Gas sector. As discussed below in Section IV, however, EPA has not provided a clear definition of that sector.

[9] In this context, "intensity" means emissions per volume of throughput, and it is expressed as a percentage.
[10] Kinder Morgan, Inc., *Environmental, Social, and Governance Report: A Sustainability Accounting Standards Board and Task Force on Climate-related Financial Disclosure Report* at pdf page 2 (2020), https://www.kindermorgan.com/getmedia/b87cb3e5-d8d5-4d42-8e27-dd66c895768d/2020-ESG-Report.pdf (Rev. Dec. 21, 2021).
[11] See id.
[12] See id. at 27 (calculation based on values given for 2018, 2019, and 2020).
[13] Proposed Rule at 20,043.

The Engine Proposal would apply emissions limits (expressed in grams per horsepower per hour ("g/hp-hr"))[14] to three broad categories of stationary, natural-gas fired, spark ignited engines in the Pipeline Transportation of Natural Gas[15] sector that have a maximum rated capacity of 1,000 horsepower or greater: (i) natural gas fired four stroke rich burn engines ("4SRB"); (ii) natural gas fired four stroke lean burn engines ("4SLB"); and (iii) natural gas fired two stroke lean burn engines ("2SLB").[16] EPA stated that it reviewed RACT NO_x rules, air permits, and Ozone Transport Commission ("OTC") model rules to develop the following emissions limits for these engines:[17]

Engine Type (would apply to new and existing)	**Proposed NO_x emissions limit (grams per horsepower hour)**
Nat Gas fired 4-stroke rich burn, ≥ 1000 HP	1.0 g/hp-hr
Nat Gas fired 4-stroke lean burn, ≥ 1000 HP	1.5 g/hp-hr
Nat Gas fired 2-stroke lean burn, ≥ 1000 HP	3.0 g/hp-hr

EPA states that these limits can be achieved on existing Engines using various retrofit technologies at the cost-per-ton threshold of less than $7,500 per ton of NO_x reduced. With regard to the 4SRB Engines, EPA states that its proposed limits are designed to be achievable for existing Engines by installing Non-Selective Catalytic Reduction ("NSCR").[18] EPA's position is that the proposed limit for 4SLB Engines can be achieved for existing Engines by installing Selective Catalytic Reduction ("SCR")—though EPA notes that in some cases it may be more cost effective to install layered combustion controls along with SCR to achieve the necessary emissions reductions.[19] Finally, with regard to 2SLB Engines, EPA states that the proposed limit is designed to be achievable for existing Engines by retrofitting them with layered combustion technologies.[20] In all cases, however, EPA notes that sources are free to install another control technology as long as the unit is still able to meet the emissions limit.[21]

Though EPA proposes certain limits for each type of Engine, the agency is also soliciting comments as to whether lower or higher limits would be more appropriate. Specifically, EPA requests comment on whether: (i) a lower emissions limit is more appropriate for 4SRB Engines;

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[14] EPA has historically set emission limits for these types of engines using g/hp-hr. Id. at 20,142.

[15] As defined in the Proposed Rule, "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." Id. at 20,176.

[16] Id. at 20,142.

[17] Id.

[18] Id.

[19] Id.

[20] Id. at 20,143.

[21] Id. at 20,142–143.

(ii) whether lower or higher emissions limits are more appropriate for 4SLB Engines; (iii) whether a lower emissions limit would be achievable with layered combustion alone for 2SLB Engines; and (iv) whether additional control technology could be installed on 2SLB Engines at or below EPA's $7,500 cost-per-ton threshold to achieve a lower emissions rate.[22] Kinder Morgan provides responses to each of these questions in Section V.A below.

In addition to requiring Engines to meet certain emissions limits, EPA proposes certain testing, monitoring, and recording requirements for these Engines. Specifically, EPA proposes: (i) requiring semi-annual performance testing in accordance with 40 C.F.R. § 60.8 to ensure the engines are meeting their NO_x emissions limits; (ii) that affected engines monitor and record hours of operation and fuel consumption to calculate ongoing compliance with the applicable emissions limit; and (iii) the use of continuous parametric monitoring systems ("CPMS") to ensure that the NO_x emissions limit is being met at all times.[23] With regard to monitoring, EPA seeks 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.[24] We provide our response to this request in Section V.F below.

IV. EPA VASTLY UNDERESTIMATES THE NUMBER OF AFFECTED ENGINES, RESULTING IN AN UNDERESTIMATE OF EMISSIONS REDUCTIONS AND UNLAWFUL OVER-CONTROL.

By requiring all stationary, natural-gas fired, spark ignited engines in the Pipeline Transportation of Natural Gas sector that: (i) have a maximum rated capacity of 1,000 horsepower or greater; (ii) fall into one of the three covered categories[25]; and (iii) are located in one of the 23 states covered by the Proposed Rule, the impact to Kinder Morgan is significant. EPA estimates Kinder Morgan operates a mere 77 Engines that would be subject to the Engine Proposal. Furthermore, EPA erroneously included 20 of the Company's *turbines* in the agency's count of affected Engines. By definition, turbines are not subject to this Proposed Rule. This means that EPA only really considered 57 of Kinder Morgan's Engines as a part of the Engine Proposal. In support of these comments, Kinder Morgan has inventoried its engine fleet through extensive analyses and determined that approximately 950 of its Engines would be subject to the Proposed Rule, a value that is orders of magnitude larger than EPA's estimates. **Figure 1** below is a graphic showing the geographic dispersion and number of Kinder Morgan Engines that would be subject to the Proposed Rule. Of the 950 affected units, 153 are 4SRB, 309 are 4SLB, and 488 are 2SLB.[26]

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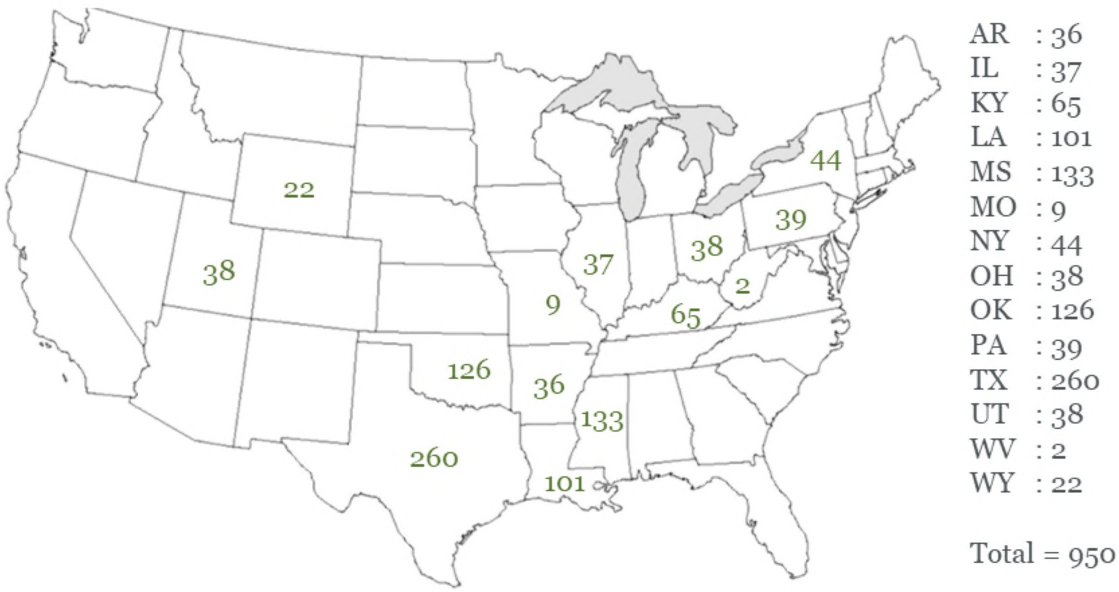
[22] Id.
[23] Id. at 20,143.
[24] Id.
[25] I.e., (i) 4SRB engines; (ii) 4SLB engines; and (iii) 2SLB engines.
[26] For purposes of Kinder Morgan's analysis, this Engine count includes engines in the gathering and boosting, processing, and transmission segments of its business units.

Figure 1: Affected Kinder Morgan Engines



Comparing EPA's estimate of the number of affected units with Kinder Morgan's on-the-ground analysis shows that EPA's estimates were off by more than a factor of 16. We expect that EPA miscounted the number of affected Engines because it relied on a NO_x emission rate of 100 tpy as a proxy for 1,000 hp Engines. This approach fails to consider utilization of 1,000 hp Engines and results in a drastic and consequential underestimation of subject Engines, not just for Kinder Morgan, but across industry. EPA's reliance on such erroneous data calls into question the validity of the Engine Proposal, as it is apparent that EPA has significantly underestimated the impacts of the Proposed Rule, thereby underestimating the expected emissions reductions.[27] The result is one of over-control. Moreover, by not considering—or even demonstrating an awareness of—the vast majority of Engines covered by the Proposed Rule, EPA has "failed to consider an important aspect of the [alleged] problem" and failed to "examine the relevant data."[28]

Not only does EPA fail to consider utilization rates of 1,000 hp Engines, but EPA's definition of the Pipeline Transportation of Natural Gas sector may sweep more broadly than it

[27] See Sierra Club v. EPA, 671 F.3d 955, 966–68 (9th Cir. 2012) (finding the EPA's action arbitrary and capricious for not utilizing a more recent model and explaining that "we should not silently rubber stamp agency action that is arbitrary and capricious in its reliance on old data without meaningful comment on the significance of more current compiled data"); Alamy, Inc. v. Califano, 569 F.2d 674, 682–83 (D.C. Cir. 1977) (concluding agency rule was arbitrary and capricious in part because "statistical integrity" of survey data was "seriously questioned"); New Orleans v. SEC, 969 F.2d 1163, 1167 (D.C. Cir. 1992) ("We have held that an agency's reliance on a report or study without ascertaining the accuracy of the data contained in the study or the methodology used to collect the data 'is arbitrary agency action, and the findings based on such a study are unsupported by substantial evidence.'" (quoting Home Health Care, Inc. v. Heckler, 727 F.2d 587, 592 (D.C. Cir. 1983))).
[28] State Farm Mut. Auto. Ins. Co., 463 U.S. at 43.

appears EPA intended. As defined in the Proposed Rule, "Pipeline transportation of natural gas" means:

> [T]he 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.[29]

At base, this scope is unclear, which impacts everything that falls under the Proposed Rule. This definition could arguably include not just the transmission segment of the natural gas industry, but also the gathering and boosting and processing segments. However, the Proposed Rule does not discuss gathering and boosting or processing activities. In particular, EPA's Engine count does not appear to consider Engines in the gathering and boosting or processing segments, and the various technical support documents similarly fail to consider these other segments of the oil and gas industry. If EPA seeks to regulate Engines in the gathering and boosting or processing segments, then it has fallen short of the CAA's requirement to provide key information and supporting rationale to the public.[30] Before EPA can go forward with the Engine Proposal, it must more clearly define the scope of its proposal, and then update its actual Engine counts accordingly.

The U.S. Supreme Court has previously cautioned EPA to avoid "over-control," defined as "[t]he possibility that a State might be compelled to reduce emissions beyond the point at which every affected downwind State is in attainment."[31] The Court recognized that upwind states could not be forced to reduce their emissions below their levels of significant contribution to downwind nonattainment.[32] And before the D.C. Court of Appeals in the same case, then judge and (now Justice) Kavanaugh, would have gone even further to hold that the Good Neighbor Provision of the Clean Air Act *only* empowers EPA to promulgate federal implementation plans ("FIPs") after a state "fails to make a required submission" or EPA disapproves of its SIP.[33]

The Proposed Rule would result in significant over-control because, due to its reliance on inaccurate data, the number of units that would be subject to the Proposed Rule is orders of

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[29] Proposed Rule at 20,176.
[30] See 42 U.S.C. § 7607(d)(3)(A).
[31] EPA v. EME Homer City Generation, L.P., 572 U.S. 489, 521 (2014) (citing EME Homer City Generation, L.P. v. EPA, 696 F.3d 7, 22 (D.C. Cir. 2012)).
[32] Id.
[33] EME Homer City Generation, L.P., 696 F.3d at 37 n.34. Under that standard, the EPA would not be authorized to promulgate a FIP for Arizona, California, Montana, Nevada, and Wyoming, as those states timely submitted SIPs, and the EPA has not formally disapproved of those SIPs. See Consent Decree, Downwinders at Risk v. Regan (No. 21–cv–03551, N.D. Cal.) (Jan. 12, 2022).

magnitude larger than EPA's estimations. Specifically, EPA estimates that there are 307 total engines in the Pipeline Transportation of Natural Gas sector affected by the rule,[34] only 77 (and really only 57 of those listed by EPA) of which belong to Kinder Morgan. However, Kinder Morgan alone has up to 950 Engines that would be subject to the Proposed Rule. And it appears EPA did not count or consider Engines operating in the gathering and boosting or processing segments, further undermining EPA's analysis. Additionally, emission controls would necessarily operate year-round rather than only during the ozone season (as discussed in further detail in Section V.D, below), further compounding the degree of over-control. The Proposed Rule would therefore result in significantly more emissions reductions on a national and a state-by-state basis than EPA has assumed. While EPA is permitted some "leeway" to over-control in light of the risk of "under-control,"[35] the Supreme Court was unequivocal that there were definite limits on EPA's discretion: "If EPA requires an upwind State to reduce emissions by more than the amount necessary to achieve attainment in *every* downwind State to which it is linked, the EPA will have overstepped its authority."[36]

Here, though, EPA has not disclosed what emissions reductions it is aiming to achieve with the Proposed Rule, effectively precluding any sort of mathematical analysis of over-control, or an evaluation of reasonable alternatives that could achieve the same result more efficiently. EPA's failure to provide this data is arbitrary and capricious, and EPA cannot rely on other data at a later time to support an adopted rule.[37] Thus, it could very well be that the Proposed Rule would fall into the category of over-control that the Supreme Court explicitly found would "overstep" EPA's authority. Pointedly, EPA has not provided the data necessary to support its Proposed Rule. Likewise, EPA's failure to provide data on how it calculated downwind emissions or disclose its emission reduction targets prevents Kinder Morgan and other stakeholders from being able to propose a comparable and reasonable alternative set of emission thresholds that would not run afoul of the prohibition against over-control. Kinder Morgan further adopts and incorporates by reference comments submitted by INGAA that address "over-control." In particular, given the erroneous Engine count, INGAA explains that EPA's calculation of NO_x emissions reductions from the Pipeline Transportation of Natural Gas sector is considerably lower than would occur if the Engine Proposal's emissions limits were incorporated into any final rule, by about double. This outcome results in emissions reductions far greater than EPA has proposed is required to eliminate significant contribution to downwind nonattainment or interference with maintenance.

The Texas Transport Working Groups' comments also explain that EPA has undercounted Engines that would be affected by the Proposed Rule and that therefore EPA did not fully account for NO_x emissions reductions resulting from emissions controls on Engines. More broadly, the

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[34] EPA, Non-EGU Screening Assessment Memorandum, Tables 5 and 6, Document ID: EPA-HQ-OAR-2021-0668-0150; see also EPA, *Transport Proposal – NonEGU Results – 03-16-2022*, Document ID: EPA-HQ-OAR-2021-0668-0150_attachment_2.xlsx, Tables 4 and 5.
[35] See EME Homer City Generation, L.P., 572 U.S. at 523.
[36] Id. at 521.
[37] See State Farm Mut. Auto. Ins. Co., 463 U.S. at 50 (review of agency action must be of the basis articulated by the agency itself (citing SEC v. Chenery Corp., 332 U.S. 194, 196–97 (1947))).

Texas Transport Working Group identified multiple flaws in EPA's photochemical modeling, which call into question the basis for the Proposed Rule. Kinder Morgan supports and incorporates by reference the Texas Transport Working Group's comments on these topics.

To remedy these foundational issues, EPA must re-publish a proposed rule that properly analyzes the effects on the Pipeline Transport of Natural Gas industry. Three foundational elements in that pursuit are to first ***clearly define*** the sector subject to the rule, understand ***how many*** Engines exist (and might fall under any proposed rule) across the sector, and develop ***a target for emissions reductions***. Kinder Morgan is willing to work with EPA to achieve these initial objectives.

V. IN ANY SUBSEQUENTLY REVISED DRAFT RULE, IF PURSUED BY EPA, EPA'S APPROACH MUST BE REVISED TO ENSURE ANY FINAL RULE IMPOSES LEGALY DEFENSIBLE, TECNICALLY FEASIBLE, AND COST-EFFECTIVE RULES.

Notwithstanding the foundational legal issues that undermine the Engine Proposal, Kinder Morgan offers EPA additional, and more specific, feedback regarding the proposal in the hopes that this feedback will assist EPA with development of a revised proposal. In particular, the Engine Proposal (A) is not technically feasible in all circumstances; (B) is not cost-effective in all circumstances; (C) cannot be achieved on the proposed timetable; (D) does not understand that the required controls are permanent and cannot be installed for the ozone season only; (E) fails to exempt emergency engines; and (F) requires onerous and unreasonable performance testing. We address each of these in turn.

A. <u>The Engine Proposal is Not Technically Feasible in All Instances.</u>

Kinder Morgan has serious concerns with EPA's characterization of the ready application of each of the described control technologies and the feasibility of installing the proposed control technologies on all Engines. It will be technically impracticable to retrofit certain of the Company's existing Engines to achieve the one-size-fits-all emissions standards set forth in the Engine Proposal. While Kinder Morgan does not oppose emission thresholds for *new* Engines, the technical feasibility of installing controls on any single *existing* Engine varies and depends, in part, on site-specific and Engine-specific considerations such as space for the installation of the control, the availability of sufficient power, the emissions reductions required to meet the applicable standards, and the vintage, make, and model of a particular Engine.

In explaining why some options may be technically impracticable, Kinder Morgan provides background on the type of control options available for each Engine type (i.e., 4SRB, 4SLB, and 2SLB). This background demonstrates the technical complexity of the various types of control options contemplated by the Engine Proposal and the limitations of each. As discussed in this section, not all proposed technologies are available across all relevant units, due to Engine- and site-specific considerations. The Proposed Rule's one-size-fits all approach fails to reflect this important fact. Furthermore, and an issue not considered in EPA's analysis: the addition of these technologies and layered controls will inevitably increase fuel consumption, which will, in many cases, result in increased greenhouse gas and carbon monoxide emissions.

4SRB Engines.

Kinder Morgan operates approximately 150 4SRB Engines that would be subject to the Engine Proposal. Regarding 4SRB Engines, EPA states that its proposed limits are designed to be achievable for existing Engines by installing NSCR.[38] Kinder Morgan offers that in addition to NSCR, layered combustion controls applicable to 4SRB Engines include turbocharging and air-fuel ratio controllers ("AFRC") may be available. NSCR is a post-combustion approach, whereas layered combustion addresses the combustion process itself. Layered combustion approaches seek to reduce the combustion temperature because much of the NO_x created by RICE results from higher combustion temperatures within the cylinder.[39]

NSCR uses the residual hydrocarbons and carbon monoxide ("CO") in the engine exhaust as a reducing agent for NO_x. In NSCR systems, hydrocarbons and CO are oxidized by oxygen and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a precious metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to water and carbon dioxide, while reducing NO_x to N_2. The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of four percent or less. As you approach leaner operation for NO_x reduction, the effectiveness of NSCR is reduced as exhaust temperatures decrease and exhaust oxygen levels increase. NSCR is generally only available for 4SRB naturally-aspirated engines and some 4SRB turbocharged engines. Engines operating with NSCR require tight air-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. Rich-burn engines have lower oxygen levels and higher temperatures in the engine exhaust, which allows for the use of NSCR.

AFRC systems can be used to adjust and optimize operating parameters on natural gas-fired engines, such as air manifold pressure and temperature and fuel delivery to the combustion chambers. Optimizing engine operation with an AFRC system raises the heat capacity of the combustion mixture, which results in lower combustion temperatures and lower NO_x formation. The feasibility of this approach depends on engine make and model.

Similarly, Turbochargers (often in conjunction with intercooling) increase the air charge density and obtain leaner air-fuel ratios. These leaner air-fuel ratios raise the heat capacity of the mixture, which results in decreased peak combustion temperatures, in turn reducing NO_x formation. Notably, all of Kinder Morgan's 4SRB Engines covered by the rule already have turbochargers, meaning that turbocharging is not an available control that can be added for *additional* emissions reductions.

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[38] Proposed Rule at 20,142.

[39] Notably, lowering the combustion temperature to avoid NO_x emissions also results in less complete combustion. Therefore, combustion control requires a tradeoff—lower temperatures reduce NO_x production but increase carbon monoxide resulting from incomplete combustion.

Importantly, however, some of Kinder Morgan's 4SRB Engines cannot achieve EPA's proposed 1.0 g/hp-hr emissions rate limit even with *both* NSCR and layered combustion controls. This is primarily due to the vintage design of the individual cylinder geometry and the fact that most of these engines are not in production today, which limits availability of parts and retrofit technologies. The takeaway is that although EPA is correct that layered combustion and NSCR are available control technologies for 4SRB Engines, these approaches are not feasible in all circumstances given site- and Engine-specific considerations and would not be sufficient to reduce emissions to the required limit for some of Kinder Morgan's Engines.

Based on preliminary assessments, the Company anticipates that over 15 4SRB Engines would require application of NSCR to meet the proposed 1.0 g/hp-hr limit. Of that subset of 4SRB Engines, Kinder Morgan would also have to add layered technologies such as AFRC to at least three of these 4SRB Engines in order to meet the standard (if feasible) and will have no margin for error against the standard even after applying the required controls. Beyond those approximately 15 4SRB Engines, Kinder Morgan also operates an additional approximately 25 4SRB Engines that already have NSCR, but that would require the Company also add AFRC to meet the 1.0 g/hp-hr limit. The Company also operates approximately 10 4SRB Engines that have all available controls on them. The Company's only option is to attempt to tune those Engines to meet the standards, but at present, even with all available controls, nearly half of these 10 Engines exceed EPA's proposed emissions limits. The incremental margin for reduction will undoubtedly be considerably more difficult to achieve, and with much less certainty. These considerations do not account for costs-per-ton estimates, which we discuss below. Even where NSCR or layered combustion is feasible, it is cost-prohibitive in some cases.

4SLB Engines.

Kinder Morgan operates approximately 310 4SLB Engines that would be subject to the Engine Proposal. EPA suggests the proposed limit for 4SLB Engines can be achieved for existing Engines by installing SCR, or layered combustion controls along with SCR to achieve the proposed 1.5 g/hp-hr limit.[40] SCR is a post-combustion control system meaning that it is an "add-on" control system that is applied after combustion occurs. It removes NO_x from the exhaust gas of an engine by causing a chemical reaction between NO_x, ammonia, and oxygen. The ammonia gas is added prior to the exhaust reaching the SCR catalyst, and the chemical reaction occurs as the exhaust passes through the catalyst chamber. The result is that NO_x in the exhaust gas is transformed into nitrogen gas and water vapor, both of which are harmless.

SCR is frequently the only option for vintage engines because manufacturers have not developed (and likely will not develop) combustion technology to reduce NO_x from them. In these situations, SCR is the only available technology to reduce even a small amount of emissions. That said, SCR is rarely applied—and Kinder Morgan has never retrofitted units with SCR in its natural gas system—which is an important fact given that the Company is one of the largest natural gas

[40] Proposed Rule at 20,142.

infrastructure and transmission companies in the U.S. This is largely because SCR is an extremely expensive and complex control technology, as discussed in more detail below, that also requires continued performance monitoring and additional, ongoing operations and maintenance costs. Furthermore, for the SCR system to operate properly, the exhaust gas must be within a specific temperature range, and the ratio of ammonia to NO_x must be accurately controlled. To achieve the best control over NO_x output, certain combustion controls may be required. Unfortunately, however, not all engines are suitable for the addition of such controls. This ultimately means that for some engines, SCR simply is not a feasible control technology. Again, because it bears repeating, certain engine-specific and site-specific factors dictate whether SCR is a feasible control technology—it is not technically feasible in all circumstances.

For some engines (1990 and more recent), however, options in addition to SCR are available to reduce emissions to the proposed limit. These options include turbocharging, high pressure fuel injection, and pre-chamber ignition. Turbocharging was discussed above for 4SRB engines. However, high pressure fuel injection and pre-chamber ignition are not techniques employed for 4SRB engines, so Kinder Morgan addresses them here in discussing 4SLB engines. High-pressure fuel injection improves air-fuel mixture and reduces NO_x formation by inducing turbulence. Pre-chamber ignition is used in extremely lean combustion conditions to increase combustion stability while nevertheless maintaining a lean (and lower temperature) combustion environment. A disadvantage of pre-chamber ignition technology is the creation of a high temperature zone within the pre-chamber, which leads to a localized spike in NO_x formation. This can reduce the overall effectiveness of that control technology.

Generally, high pressure fuel injection and pre-chamber ignition would not be used in conjunction; rather, one or the other would be used. But, as the Proposed Rule appears to acknowledge, independent unit-specific considerations can affect whether these approaches are sufficient for achieving the proposed emissions limit.[41] As noted above, these approaches are generally only available for newer engines. Nevertheless, even for some newer engines, their designs may not allow for the addition of pre-chamber ignition or turbochargers because the engine may require such extensive modification that it would be more cost effective to replace the *entire* engine. An emissions threshold that amounts to replacement of an existing engine with a new engine is wholly inappropriate.

Based on preliminary assessments, the Company anticipates that approximately 10 4SLB Engines would require SCR to meet the proposed 1.5 g/hp-hr limit. All of these Engines are older Engines, which means SCR is the *only* available control option. Moreover, adding SCR systems to these Engines would require custom retrofit because these models are no longer in production, and options such as turbocharging, high pressure fuel injection, and pre-chamber ignition are not technically feasible. These considerations do not account for costs-per-ton estimates, which we

[41] See id. at 20,089 (discussing how CoST model does not consider unit-specific engineering analyses), at 20,142-043 (noting variations in effectiveness of controls depending on unit-specific factors).

discuss below. In these particular cases, application of SCR is economically infeasible on a cost-per-ton basis.

2SLB Engines.

Kinder Morgan operates nearly 500 2SLB Engines that would be subject to the Engine Proposal. Regarding 2SLB Engines, EPA states its proposed limit of 3.0 g/hp-hr is achievable for existing Engines by retrofitting them with layered combustion.[42] These layered combustion options are the same as those for 4SLB Engines discussed above, including turbocharging, high pressure fuel injection, and pre-chamber ignition. As with the discussion of these control technologies for 4SLB Engines offered above, Kinder Morgan emphasizes that such technologies are not universally feasible for all 2SLB Engines.

In addition, SCR is a potential available control technology for 2SLB engines. However, for 2SLB engines, the addition of SCR is even more complicated than for 4SLB engines, and again, it is rarely applied given the technical complexities compounded by the overreaching costs. First, the relationship between engine load and exhaust flow rate is more complex than for 4SLB engines, which makes it more difficult to control a proper ratio of NO_x to ammonia in the SCR. Second, SCR systems create backpressure in the exhaust system, and 2SLB engines are more susceptible to adverse effects caused by backpressure. Increased backpressure on a 2SLB engine reduces engine airflow, which reduces the efficiency of exhaust gas purging and can result in increased NO_x output, engine knock, increased CO output, increased fuel consumption, increased cooling load, and decreased engine maximum load. Third, the use of direct cylinder lubrication in 2SLB engines likely results in faster SCR catalyst degradation, although long-term issues like this have not been studied extensively for 2SLB engines. Despite these difficulties, there are instances where the engine-specific circumstances dictate that SCR is the only available option for a particular 2SLB engine to meet the Proposed Rule's specified maximum emissions rate limit.

Based on preliminary assessments, the Company anticipates that approximately 110 2SLB Engines would require SCR to meet the proposed 3.0 g/hp-hr limit. For some 50 of these approximately 110 2SLB Engines Kinder Morgan has already expended significant capital costs in applying turbocharging, high pressure fuel injection, or pre-chamber ignition work to reduce emissions as required by the relevant state. For these 50 Engines, Kinder Morgan would still be required to apply SCR to meet the proposed standards. These considerations do not account for costs-per-ton estimates, which we discuss below. Even where SCR or layered control is feasible, it is cost-prohibitive in many cases.

Turning back to all engine types, for all three classes of Engines, EPA notes that sources are free to install "another control technology" as long as the unit is still able to meet the emissions limit.[43] However, there are no other control technologies. EPA has identified them all: NSCR, SCR, and layered combustion. While the Company recognizes that technologies continue to

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[42] Id. at 20,143.
[43] Id. at 20,142–143.

advance, it is highly unlikely that technologies in this arena will advance faster than EPA's expected timeline for compliance with the proposed emissions limits. It is inaccurate to suggest that other technologies exist and can be cost-effectively implemented in response to the Proposed Rule.

As noted above, EPA requests comment on: (i) whether a lower emissions limit is more appropriate for 4SRB Engines; (ii) whether lower or higher emissions limits are more appropriate for 4SLB Engines; (iii) whether a lower emissions limit would be achievable with layered combustion alone for 2SLB Engines; and (iv) whether additional control technology could be installed on such Engines at or below EPA's $7,500 cost-per-ton threshold to achieve a lower emissions rate. As explained, the limits as currently proposed are not technically feasible in all circumstances. Kinder Morgan respectfully submits that if current limits are not achievable in some circumstances, then lower limits are likewise impossible for 4SRB Engines, 4SLB Engines, and 2SLB Engines in even more circumstances. Nor can additional control technology be installed on 2SLB Engines at or below the $7,500 cost-per-ton threshold to achieve a lower emissions rate in all circumstances, as discussed in more detail below. The negative consequences of EPA's over-reaching and one-size-fits-all proposal are significant and underscore the need for a revised and alternative approach.

Accordingly, and as discussed in further detail in Section VI.B below, rather than adopting the rule as currently proposed—or revising it to include more stringent emissions limits—Kinder Morgan respectfully requests that EPA revise the Engine Proposal as a model rule that states can adopt in their individual state implementation plans ("SIPs"). The model rule must incorporate emissions averaging for Engines together with an option to demonstrate economic infeasibility on an Engine-by-Engine basis.

B. <u>The Engine Proposal is Not Cost-Effective In All Instances.</u>

EPA suggests that the proposed emissions limits can be achieved on existing Engines, by 2026, using various retrofits at what it has determined to be a reasonable cost threshold of $7,500 per ton of NO_x reduced. As evidenced by other state and federal rulemakings, $7,500 per ton is at the high-end of what has been determined as cost-effective in other NOx rulemakings.[44] Assuming

[44] For example, in the recent New Mexico (2019) regional haze planning process, the New Mexico Environment Department ("Department") determined that an appropriate cost-effectiveness threshold for requiring controls was $7,000 per ton of pollutant reduced, including NO_x. In the recent (2022) New Mexico ozone precursor rulemaking, the Department and New Mexico Environment Improvement Board determined $7,500 per ton of NO_x reduced was a reasonable cost-effectiveness threshold. <u>See</u> Proposed § 20.2.50.113(B) New Mexico Code of Administrative Regulations (May 6, 2021), https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2018/08/Proposed-Part-20.2.50-May-6-2021-Version.pdf. Colorado's Regulation No. 7, applicable to certain rich burn RICE (2009), established a cost-per-ton threshold for NO_x reduced of $5,000 per ton, which amounts to $6,400 in today's dollars. <u>See</u> 5 CCR 1001-9:E.I.D.4.a.(ii) (inflation adjustment calculated using the Bureau of Labor Statistics' online calculator: https://www.bls.gov/data/inflation_calculator.htm). New York established a threshold of $3,000 per ton of NOx reduced in 1994, which equates to approximately $5,500 per ton reduced after adjusting for inflation. <u>See</u> New York State Department of Environmental Conservation, DAR-20: Economic and Technical Analysis for Reasonably Available Control Technology (RACT) Networks (Aug. 8, 2013), at 1,

for argument's sake that $7,500 per ton reduced may be a reasonable threshold, it should certainly be considered a "not to exceed" threshold. More fundamentally, it is simply not cost effective to reduce emissions to the rates set forth in the Engine Proposal for each and every one of Kinder Morgan's Engines. As a result, the Proposed Rule would impose severe costs on Kinder Morgan and the natural gas transport sector—risking natural gas supply chain disruptions—and should be reconsidered.

1. EPA's Cost Data is Outdated and EPA Does Not Appear to Account for Inflation.

EPA's Proposed Rule uses 2016 dollars to further assess potential NO_x emissions control strategies, estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries.[45] In doing so, EPA came up with a cost threshold of $7,500 per ton of NO_x reduced and identified controls for non-EGU emissions units that cost up to this amount.[46] While EPA states that these dollars are discounted to 2022 and they are "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," it provides no other support for using cost data that is over six years old.[47] Even if one were to assume that EPA could justify that $7,500 per ton of NO_x reduced is reasonable, EPA's use of 2016 dollars to evaluate the cost of technologies will not lead to an accurate analysis. A number of dramatic macroeconomic changes have occurred since 2016 that have led to rising supply times and service costs, including the COVID-19 pandemic, the war in Ukraine, and inflation. According to a May 11, 2022 release by the Bureau of Labor Statistics, inflation has risen 8.6% in just the last 12 months, with the energy index surging to 34.6% year over year (natural gas alone increased 30.2% in the same period).[48] This is the highest level of

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https://www.dec.ny.gov/docs/air_pdf/dar20.pdf. In Pennsylvania's RACT III program, the agency established cost-effectiveness benchmarks for installing RACT-level controls at $3,750 per ton of NO_x reduced and $7,500 per ton of VOC reduced. See Technical Support Document for Proposed Rulemaking (Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS RACT III)), at 12, https://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2021/May%2019/02_7-561_RACT%20III%20Major%20Source/04b_7-561_RACT%20III%20VOC_Proposed_TSD%20w%20APPENDICES.pdf.

[45] Id. at 20,083 ("[A]ll non-EGU cost estimates in the assessment and presented in the rest of this section are in 2016 dollars."); 20,089 ("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)"; 20,090 ("Note that the average cost per ton values are in 2016 dollars."); 20,096 ("Using a $7,500/ton (in 2016 dollars) marginal cost threshold"); 20,155 ("For non-EGUs, EPA analyzed this proposed rule using a marginal cost threshold of up to $7,500 per ton (2016$) for 2026").

[46] Proposed Rule at 20,083.

[47] Id. at 20,047 ("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."); 20,048 ("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 $1,500 million"); 20,159; ("2016 dollars discounted to 2022"); 20,160 ("Millions 2016$, discounted to 2022").

[48] Bureau of Labor Statistics, *Consumer prices up 8.6 percent over year ended May 2022* (June 14, 2022), https://www.bls.gov/opub/ted/2022/consumer-prices-up-8-6-percent-over-year-ended-may-2022.htm.

inflation seen in more than 40 years.[49] Not accounting for these and other matters in its calculations of the cost of control technologies further compounds the inaccuracy of EPA's cost data. To properly evaluate a proposal with such far-reaching and costly consequences, EPA should use present dollars to evaluate the impact of its proposal.

2. Kinder Morgan's Cost-Analysis Demonstrates that EPA's Rule is Not Cost-Effective in Many Circumstances.

On top of—or perhaps because of—its use of outdated cost data, EPA's estimated compliance costs for Engines do not reflect reality for many of Kinder Morgan's Engines. Even if applying one or more of the technologies described above is technically feasible, in many instances, it remains cost-prohibitive. The Engine Proposal and supporting information do not accurately reflect this fact. In fact, specific details regarding how EPA arrived at its cost-per-ton estimates are not available, or at least not clear. It appears that EPA rolled up cost ranges for Engines, which means that the costs are averaged across units. In turn, EPA's Engine Proposal fails to appropriately account for those Engines that will, in fact, exceed a cost-per-ton threshold of $7,500. As outlined below, and when reviewed on a case-by-case basis, a considerable number of Engines will have much higher costs than EPA presumes. In addition, because EPA underestimates the total number of Engines that would be subject to the Engine Proposal it has not fully considered the total capital costs required to implement its proposal, which are far from insignificant.

The economic reasonableness of installing controls on any individual engine will vary and depend on variety of factors, including that the demand for these various technologies will certainly increase market costs. In short, there is significant heterogeneity across Kinder Morgan's approximately 950 Engines resulting from differences like site layout, vintage, and manufacturer.[50] As a result of this variability, Kinder Morgan is unable to fully analyze the costs of the Proposed Rule. However, Kinder Morgan believes that the cost-analysis examples and total cost estimates provided below are indicative of the burdens imposed by the Proposed Rule, and these examples demonstrate why EPA's Proposed Rule would not be cost-effective in many circumstances. This concrete evidence provides strong support for EPA to develop a model rule for states to adopt to allow for emissions averaging and an Engine-by-Engine demonstration of economic infeasibility. Such an approach is imperative to respond to the noteworthy technical and cost issues that would arise from adopting the Engine Proposal without revisions.

Before turning to the cost examples, Kinder Morgan provides background on the process it used to develop each case study. In connection with similar rulemakings and regulatory

[49] NBC, *Inflation hits 40-year high of 8.5 percent because of war in Ukraine, rent hikes* (Apr. 12, 2022), https://www.nbcnews.com/business/consumer/inflation-march-2022-hits-record-high-data-stats-details-rcna23654.

[50] Notably, the Proposed Rule acknowledges such heterogeneity. See Proposed Rule at 20,076 ("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."). The Proposed Rule's approach for emissions reductions should reflect such heterogeneity rather than imposing a one-size-fits all emissions limit.

compliance undertakings in other states, Kinder Morgan has conducted analyses and sought out vendor quotes to assess the potential impact of various NO_x emissions standards and to deploy NO_x emissions reduction projects. The process that Kinder Morgan undertook to produce the attached case study-analyses was extensive, involving several layers of review and close coordination with vendors. Below, we present a summary of these various analyses, which evidence that in many circumstances, it is not cost-effective to achieve the proposed thresholds.

Using these site-specific estimates, Kinder Morgan then developed a cost-per-ton estimate applying the methodologies outlined in EPA's Cost Control Manual. To develop a cost-per-ton estimate, one of the most important assumptions is how many hours of runtime a particular unit will experience going forward. This is because runtime is directly proportional to emissions, but investment in a control technology is largely a fixed, one-time cost. Kinder Morgan determined that using average runtime over the most recent five-year period is most reflective of past and future operations because year-specific events are smoothed out. EPA's cost analysis used the year 2019, and Kinder Morgan's five-year fleet average runtime is similar in value to its 2019 fleet average runtime, but dissolves any anomalies in the single year data set.

Examples 1 & 2: SCR Added to 2SLB Worthington Engines.

For the following two case-studies, SCR is the only compliance option for these units to lower the NO_x emissions rate to the proposed 3 g/hp-hr limit. As noted above, Kinder Morgan has never retrofitted units with SCR in its natural gas system; these remain estimates only.

Example 1. Kinder Morgan evaluated the costs of adding SCR to a 2SLB Worthington Engine (in the Northeast). As demonstrated in the project cost estimate case study attached as Exhibit 1, the capital cost to install SCR is \$5,635,359. The largest component of this cost (\$2,083,100) is for the SCR primary construction contractor, and the second-largest component (\$1,778,700) is for the SCR materials themselves. It is also important to note that this estimate is dated April 21, 2020. Given recent inflation and supply chain delays, the costs would be even higher, as demonstrated by a letter Kinder Morgan received from a vendor indicating that the vendor is seeing "**25% pricing increase** and 4-6 week longer manufacturing lead times" from the initial quote used in the case study.[51] Using EPA's cost calculation methodologies, Kinder Morgan estimates that the resulting cost-per-ton of NO_x reduced by adding SCR at this engine would be \$109,301, as reflected in Table 1. This cost-per-ton value dramatically exceeds the \$7,500 level that EPA identified as reasonable.

Example 2. Similarly, Kinder Morgan evaluated the costs of adding SCR to a different type of 2SLB Worthington Engine, and Kinder Morgan's project cost estimate found a capital cost of \$6,215,151 to install SCR.[52] Like the analysis for the unit in the Northeast, the largest component of this cost (\$3,138,700) is for the SCR construction contractor (both the primary and

[51] See Exhibit 15 (letter from vendor indicating that cost has likely risen 25% from the original quote) (emphasis added).
[52] See Exhibit 2.

secondary), and the second-largest component ($1,326,500) is for the SCR materials. This estimate is dated September 8, 2021, meaning that the inflationary environment has likely driven this cost up as well. Further, the resulting cost per ton of NO_x reduced by adding SCR at this engine would be $19,158 per ton,[53] which is more than double the $7,500 value.

As the foregoing case studies demonstrate, requiring Kinder Morgan to incur these costs to comply with the proposed emissions rate limits for 2SLB Engines would be unreasonable and contrary to the policy fundamentals that EPA states in its proposal. As noted above, SCR is the only compliance option for these units, and in total, Kinder Morgan has approximately 120 2SLB Engines for which SCR is the only control option to lower the NO_x emissions rate to the proposed 3 g/hp-hr limit. Kinder Morgan expects the case studies presented above would be generally representative of the costs for each SCR installation. Thus, using a relatively conservative $5 million per SCR installation and assuming that SCR is technically feasible on each unit, Kinder Morgan would need to spend $600 million on SCRs at all these types of units to comply with the proposed limit. However, using the cost for the unit from Example 2 as the per-engine cost would require approximately $750 million to make the necessary modifications to all 120 units.

Examples 3 – 6: Engine Combustion Alterations on 2SLB Engines.

For the following four case-studies, engine modifications through layered control are the most effective options to achieve the proposed emissions rate of 3 g/hp-hr.

Example 3. Kinder Morgan evaluated engine modifications (pre-combustion chambers, along with accompanying hardware) to Cooper GMVA-10 engines. Kinder Morgan's detailed cost estimate determined that the capital cost for the entire four-unit station would be $15,433,535, for a per-unit cost of $3,858,384.[54] Materials represented the largest cost ($2,734,275 per unit). The resulting cost per ton of NO_x reduced per unit would be $8,589 per ton,[55] which is above the $7,500 level. Kinder Morgan has nearly 270 units for which this would be the indicative cost to perform such upgrades. The total cost on all such units would be approximately $1.04 *billion*.

Example 4. For engine modifications (upgrading intercooler and adding pre-combustion chambers) on a Clark TLA-6 2SLB unit, Kinder Morgan determined the upgrade cost would be $5,903,899.[56] Kinder Morgan has over 90 units for which this would be the indicative capital cost to perform such upgrades. This would result in a cost of $5,948 per ton of NO_x reduced.[57] The total cost on all such units would be approximately $530 million.

Example 5. For a Cooper 16W330 unit, Kinder Morgan evaluated the costs of re-aeroing the turbocharger and pre-combustion chambers to this unit. These are the modifications necessary to reach the proposed 3 g/hp-hr limit. Kinder Morgan's analysis shows that the cost of these

[53] See Table 1.
[54] See Exhibit 3.
[55] See Table 1.
[56] See Exhibit 4.
[57] See Table 1.

upgrades would be $5,942,809 per unit,[58] with a resulting cost of $67,672 per ton of NO_x reduced,[59] far above the $7,500 threshold. Kinder Morgan has several similar units.

Example 6. For a Clark TCV-16 unit, Kinder Morgan evaluated the costs of pre-combustion controls, turbocharger work, along with an intercooler to reach the proposed emissions limit of 3 g/hp-hr. The evaluation found a total capital cost of $6,839,263.[60] Kinder Morgan has more than 20 units that are similar to this one. A project like this one would have a NO_x reduction cost of approximately $1,000 per ton.[61]

Together, the wide variance in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program and an option to assess economic infeasibility on an Engine-by-Engine basis (discussed in further detail below).

Examples 7 – 11: 4SLB SCR and Engine Combustion Alteration.

Example 7. Kinder Morgan evaluated the cost of adding an SCR system to one of its Cooper Type 26 Engines to meet the proposed 1.5 g/hp-hr limit for 4SLB Engines. SCR is the only option for Engines of this type and vintage because vendors do not have combustion control packages available. Kinder Morgan estimated that the capital cost to install the SCR system and make necessary upgrades to accommodate the SCR would be $6,320,443.[62] The SCR addition project would have a cost of $9,630 per ton of NO_x reduced, assuming that the units run 50% of the time annually, which is conservatively high for these particular units and skews the cost-per-ton value lower than anticipated.[63] In total, Kinder Morgan has approximately 10 units for which similar costs would be expected.

Example 8. Kinder Morgan evaluated the cost for one of its Ingersoll-Rand KVS-412 Engines to meet a 1.5 g/hp-hr limit. For this level, high pressure fuel injection, turbo re-aeroing, and pre-combustion chambers were all required. These technologies are the most cost-effective to install and operate. The total capital cost of these upgrades was determined to be $6,434,942.[64] Based on the level of emissions reductions achieved, the resulting cost per ton of NO_x reduced would be $5,931.[65] This estimate is indicative of costs for many of Kinder Morgan's Ingersoll-Rand and Cooper 4SLB units. Kinder Morgan has approximately 25 similar units.

Example 9. Kinder Morgan evaluated the cost of combustion controls for its Caterpillar 3516 4EK Engines to meet the proposed 1.5 g/hp-hr limit. Caterpillar provides a low-emissions

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[58] See Exhibit 5.
[59] See Table 1.
[60] See Exhibit 6.
[61] See Table 1.
[62] See Exhibit 7.
[63] See Table 1.
[64] See Exhibit 8.
[65] See Table 1.

toolkit for such units, and the toolkit could be installed for approximately $322,000.[66] The associated cost per ton of NO_x reduced for this kit would be $225,587.[67] This extremely high value results in large part because the total emissions reductions at the unit would be modest. Kinder Morgan has more than 15 units like this one.

Example 10. Kinder Morgan also evaluated the cost of combustion controls for its Caterpillar 3516 WPW Engines that would meet the proposed 1.5 g/hp-hr limit. Caterpillar also provides a low-emissions toolkit for such engines, and the toolkit could be installed for approximately $196,000 in parts and labor.[68] The associated cost per ton of NO_x reduced for this kit would be $2,152.[69] Kinder Morgan has nearly 20 Caterpillar 3516 WPW Engines like these. Again, the variety in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program.

Example 11. It is important to note, however, that not all of Kinder Morgan's Caterpillar Engines are suitable for an upgrade kit. Kinder Morgan owns three Caterpillar 3512 units, for which Caterpillar does not offer an upgrade kit. To satisfy the proposed 1.5 g/hp-hr emissions limit, these engines would either need to install SCR or be replaced. However, replacement of the engine at a cost of millions of dollars is cheaper than SCR for these engines. SCR would also have higher operating costs than a replaced Caterpillar 3512. The total replacement cost would be $648,890,[70] for a cost per ton of NO_x reduced of $10,165.[71] Kinder Morgan maintains that while EPA may, pursuant to the CAA, impose reasonable emissions limits, those limits cannot be so stringent that they require *replacement* of existing units. This result would be contrary to the CAA and EPA's interpretations.[72]

Examples 12 – 14: 4SRB Engines.

Example 12. Kinder Morgan evaluated the costs for a 4SRB Ingersoll-Rand KVG-310 to meet the proposed 1 g/hp-hr limit. The project would require NSCR, AFRC, and adding turbochargers to meet the proposed 1 g/hp-hr limit, resulting in a total project cost of $5,684,158.[73] This estimate reflects the likely costs for all three of Kinder Morgan's 4SRB Ingersoll-Rand Engines. Based on the level of emissions reductions achieved, the resulting cost per ton of NO_x reduced would be $684,169, which greatly exceeds the $7,500 level.[74]

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[66] See Exhibit 9.
[67] See Table 1.
[68] See Exhibit 10.
[69] See Table 1.
[70] See Exhibit 11.
[71] See Table 1.
[72] See 42 U.S.C. § 7502(c)(1) (applying RACT requirement to *existing* sources); see also 40 C.F.R. § 51.100(o) (defining RACT to mean "devices, systems, process modifications, or other apparatus or techniques that are reasonably available [providing factors to consider]").
[73] See Exhibit 12.
[74] See Table 1.

Example 13. For one 4SRB Waukesha 7042 Engine, Kinder Morgan estimated the cost to add an NSCR catalyst and an AFRC, both of which would be required to meet the proposed 1 g/hp-hr limit. The total estimated cost was $278,318 per unit.[75] In total, Kinder Morgan has approximately 25 Engines like this one, for which a similar cost would be expected. Based on the level of emissions reductions achieved, the resulting cost per ton of NO_x reduced would be $1,466, below the $7,500 level.[76]

Example 14. For another 4SRB Waukesha 7042 Engine, Kinder Morgan also estimated the cost to add only an AFRC. The total estimated cost was $157,709 per unit.[77] In total, Kinder Morgan has approximately 15 Engines like this one, for which a similar cost would be expected. Based on the level of emissions reductions achieved, the resulting cost per ton of NO_x reduced would be $11,043, which exceeds the $7,500 level.[78]

These capital costs and costs per ton of NO_x reduced highlight the wide variance of control costs that occur, even within the same type of Engine (e.g., 4SRB Engines), as summarized in **Table 1**, below. The wide variance in costs supports Kinder Morgan's alternative proposal that does not use a one-size-fits-all approach, in contrast to the Engine Proposal.

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[75] See Exhibit 13.
[76] See Table 1.
[77] See Exhibit 14.
[78] See Table 1.

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Table 1: Summary of Kinder Morgan's Cost-Effectiveness Analyses

Ex. #	Project	Engine Cycle	Control Technology	# of similar units	# of units that exceed $7,500/ton[79]	Estimated Capital Cost	Total Direct Annual Costs	Total Indirect Annual Costs	Total Annual Costs	Cost Effectiveness ($/Ton)
1	SCR added to 2SLB Worthington	2SLB	SCR	95	95	$5,635,359	$83,532	$621,367	$704,899	$109,301
2	SCR added to different 2SLB Worthington	2SLB	SCR	27	27	$6,215,151	$234,392	$684,436	$918,828	$19,158
3	Combustion controls for GMVA-10	2SLB	Turbo, PCC, Intercooler	189	142	$3,858,384	$48,027	$428,070	$476,097	$8,589
4	Combustion controls for Clark TLA-6	2SLB	Turbo, PCC, Intercooler	96	84	$5,903,899	$58,401	$651,065	$709,466	$5,948
5	Combustion controls for Cooper 16W330	2SLB	Turbo, PCC, Intercooler	6	5	$5,942,809	$57,273	$654,811	$712,084	$67,672
6	Combustion controls for Clark TCV-16	2SLB	Turbo, PCC, Intercooler	21	6	$6,839,263	$63,465	$752,327	$815,792	$1,000
7	SCR added to Cooper Type 26	4SLB	SCR	9	9	$6,320,443	$176,422	$695,890	$872,312	$9,630
8	Combustion controls for Ingersoll-Rand KVS-412	4SLB	High Pressure Fuel, Turbo, PCC, Intercooler	26	18	$6,434,942	$60,711	$708,345	$769,056	$5,931
9	Combustion controls for Caterpillar 3516 4EK	4SLB	Low emissions kit	16	14	$322,130	$29,633	$43,400	$73,033	$225,587
10	Combustion controls for Caterpillar 3516 WPW	4SLB	Low emissions kit	19	15	$196,158	$29,436	$29,697	$59,133	$2,152
11	SCR for Caterpillar 3512	4SLB	Replacement	3	3	$648,890	$33,084	$78,945	$112,028	$10,165
12	Combustion controls and NSCR for Ingersoll-Rand KVG-310	4SRB	NSCR Catalyst, AFR controls, Turbocharger	3	3	$5,684,158	$55,970	$626,676	$682,645	$684,169
13	NSCR and AFRC for 4SRB Waukesha 7042	4SRB	NSCR Catalyst & AFR controls	25	19	$278,318	$40,125	$38,634	$78,759	$1,466
14	AFRC for 4SRB Waukesha 7042	4SRB	AFR controls	15	14	$157,709	$29,270	$25,515	$54,784	$11,043

[79] Kinder Morgan reasonably applied a 5-year average for operating hours when developing its cost-effectiveness analysis, as described above.

Estimates of Fleetwide Costs.

From the detailed case studies developed above, Kinder Morgan then evaluated the likely total costs of complying with the Proposed Rule across its entire fleet of Engines. In part because EPA's Engine Proposal does not allow for an Engine-by-Engine showing of economic infeasibility or emissions averaging, total costs to Kinder Morgan to implement the rule as proposed, without the reasonable provisions discussed in these comments, would be on average, approximately ***$4.3 million per Engine***.

C. The Timetable for Installation of Controls and Meeting the Proposed Emissions Thresholds is Unreasonable (if not Impossible).

Even assuming the Engine Proposal's limits are technically feasible and cost-effective—and we respectfully submit that they are not in many circumstances—other technical limitations expose the shortcomings in the Engine Proposal. The chief flaw is EPA's failure to consider the realities of its proposed timeline for implementing the emissions limits on Engines. EPA is proposing to require compliance with the control requirements for all non-EGUs across 23 states *no later than the 2026 ozone season* (May through September) meaning that the emission controls would need to be installed by April 30, 2026.[80] This is simply an unreasonable timeline. EPA states that if the Proposed Rule is finalized in early 2023, "the final rule would provide more than three years for . . . non-EGU sources to install whatever controls they deem suitable to comply with required emissions" and that "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."[81] EPA's assumptions are misplaced, and the agency must offer both a reasonable phased-in schedule, as well as an opportunity for an operator to request an extension of that phased-in schedule based on site-specific circumstances.

As a threshold matter, EPA cannot expect operators to begin the significant undertaking of retrofitting their engine fleets, which requires a considerable expenditure of resources and time, before the standards are set through publication of a final rule. Indeed, EPA itself acknowledges that the standards could change by soliciting comments on whether the emissions standards should go up or down.[82] Additionally, the Proposed Rule is one of the most highly contentious proposed rules that EPA has published in the recent past and significant comments are expected—as EPA has conceded by extending the comment deadline to June 21, 2022. These comments are likely to result in numerous changes to the Proposed Rule. Accordingly, EPA cannot reasonably expect operators to believe they have four years to make required changes. However, even if that were true, an additional year is still not enough time for operators to implement the changes as they currently stand in the Proposed Rule, as explained in further detail below.

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[80] Proposed Rule at 20,101–102.
[81] Id. at 20,101.
[82] Id. at 20,142–043.

EPA's position that companies can install controls by the 2026 ozone season is undermined by the Agency's substantial underestimation of affected units. As noted in Section IV above, EPA estimated that the Company has 77 Engines subject to the Engine Proposal—an estimate that includes 20 turbines not subject to the Engine Proposal. But in fact, the Company operates approximately 950 Engines. Moreover, EPA fails to consider the significant undertaking of modifying existing Engines, as well as the impact to the natural gas supply chain of taking Engines offline for a considerable amount of time to conduct necessary modifications.

First, modifying existing Engines is a significant, custom, costly, and time-intensive undertaking. This is especially relevant for Kinder Morgan because it has approximately 950 Engines that would be impacted by the Proposed Rule. It is important to put into context the size of these particular Engines. An Engine typically weighs at least 100,000 pounds, and can weigh as much as 365,000 pounds. Along with size, the Engines are highly complex and fully integrated machines. The combination of these two facts means that it is no small task to address after-market retrofit technologies on these Engines. In the case of an Engine located in an area with insufficient space to install controls, for example, the surrounding Engine site may need to be reconfigured to accommodate the control technology.

Furthermore, Kinder Morgan is aware of just two companies with the capability to design, manufacture, and install controls which would reduce NO_x emissions on certain of its Engines. Catalyst suppliers are similarly limited. And given that the proposed technologies are after-market modifications, each system must be custom designed for the relevant Engine, and the manufacturer can only work on one system at a time. As a result of the Proposed Rule, these limited number of companies will be flooded with requests by Kinder Morgan alone, let alone the rest of industry. As an illustration of the impossibility of meeting EPA's 2026 deadline, one of the companies that Kinder Morgan identified as capable of installing controls on its units has indicated that it would only be able to modify 20 or 30 Engines a year, across all of industry. Given that Kinder Morgan alone has 950 Engines and that Kinder Morgan would not be the only company competing for contracts with those suppliers, it is difficult to overstate how unrealistic EPA's proposed timeline would be. And even if the timeline could be feasible, Kinder Morgan and similarly situated companies would have to bid against each other for contracts with vendors, which raises serious concerns about increased costs resulting from such an aggressive timeline.

Second, Kinder Morgan uses these Engines to meet its obligation to the FERC to ensure the safe and efficient movement of natural gas along FERC-certificated interstate transmission pipelines to local distribution companies for ultimate distribution to residential, commercial, and other industrial consumers. To continue these operations without interruption, Kinder Morgan must install the required controls on each Engine one-by-one. Meaning, the Company cannot shut down an entire station for the six or more month period that may be required to install the control technologies.

Another very important issue that EPA has failed to consider is that each and every Engine modification must be accompanied by a permit modification. And in nearly every state, that

Engine cannot operate unless and until the permit modification is granted. In the Company's experience, it can take over a year for a state to process even the simplest permit modification. For context—and based on the Company's recent experience with permit modifications—while minor modifications can take as little as 90 days, permit modifications for major changes can take 24 months or more to process. Given the magnitude of changes that retrofitting these engines entails, it is reasonable to assume that the timelines applicable to modifications in response to the Proposed Rule will fall on the longer end, especially as state permitting agencies may be inundated with permit modification applications. Additionally, as explained immediately above, Kinder Morgan cannot shut down all of the Engines in a compressor station at once without jeopardizing the safe and reliable transport of natural gas; instead it must retrofit the Engines in a single facility one at a time. Thus, if a Kinder Morgan compressor station has three Engines subject to the Proposed Rule, it could take as long as six years to obtain the permit modifications alone. EPA fails to consider the demands on already resource-constrained state agencies, and the ultimate backlog, that would result from the proposed timeline. After giving this issue proper consideration, EPA should modify its approach to allow for greater compliance flexibility and a phased-in approach, as discussed below.

In recent rulemakings, several states have recognized what a massive undertaking it is to retrofit engine fleets with control technology, and those states have provided a much longer timetable for compliance considering *a much smaller overall count of affected engines*. For example, New Mexico has proposed a phased compliance schedule, which allows owners or operators to retrofit their natural gas-fired spark-ignition engines over a period of six years, and Colorado also provides a phased approach over a five-year period, again, as applied to a much smaller count of Engines.[83] In addition, both states offer a "company-wide plan" approach that affords the operator an opportunity to effectively average emissions reductions across its fleet in the most reasonable and cost-effective manner to achieve the same or similar overall reductions. In contrast, EPA proposes only three years for the Company to retrofit 950 engines. In other words, EPA expects Kinder Morgan to retrofit approximately 13 to 30 times the number of units as the Colorado and New Mexico rules in 1/2 the amount of time. This is simply not a reasonably expectation, and EPA must amend its approach to provide regulated entities ample time to make changes.

Indeed, EPA appears to recognize that retrofits could take longer, specifically requesting "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 one year (i.e., to May 1, 2027) based on a sufficient showing of necessity" and the specific criteria that the EPA should apply in evaluating requests for extension.[84] As EPA concedes in this solicitation, the D.C. Circuit stated in *Wisconsin v. EPA* that 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

[83] Proposed § 20.2.50.113(B) New Mexico Code of Administrative Regulations (May 6, 2021), https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2018/08/Proposed-Part-20.2.50-May-6-2021-Version.pdf; 5 Colo. Code Regs. § 1001-9:E.I.D.5.c.
[84] Proposed Rule at 20,104.

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.'"[85] Specifically, EPA notes that the criteria for an extension could include a number of matters—most of which Kinder Morgan submits it has already demonstrated by its comments herein:

> 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)**; . . . 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**.[86]

While Kinder Morgan supports a compliance deadline extension, the underlying rule affecting over 2,000 Engines[87] cannot be drafted such that every subject operator would be required to request an extension for each Engine. Rather, the rule must be drafted to reflect consideration of the technical, practical, and economic constraints on implementation at the outset, with a reasonable phase-in schedule. Such an approach is consistent with RACT, best available retrofit technology ("BART"), and the Prevention of Significant Deterioration ("PSD") program's best available control technology ("BACT") requirements.[88]

[85] Id. at 20,104 (quoting Wisconsin v. EPA, 938 F3.d 303, 320 (D.C. Cir. 2019).
[86] Id. (emphasis added).
[87] As noted in INGAA's comments, approximately 1,199 Engines would require control, an additional approximately 180 Engines (bringing the total to approximately 1,380) currently include emission controls but cannot meet the proposed limits and will therefore require incremental control, and another 678 Engines that meet the emission limits would incur incremental compliance costs to address Proposed Rule requirements for biannual emissions tests and continuous parameter monitoring (bringing the total to 2,058). INGAA Comments at Section II. Additionally, these estimates do not include pipeline companies that are not INGAA members. Id.
[88] 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979) ("EPA has defined RACT as: The lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."); 40 C.F.R. § 51.301 ("Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."); 42 U.S.C. § 7479(3) ("The term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, **taking into account energy, environmental, and economic impacts and other costs**, determines is achievable for such facility

Finally, as discussed in further detail in Section V.B.2 above, retrofitting engines is extremely costly, and it is not reasonable to expect operators to absorb the costs of retrofitting their Engine fleets on EPA's proposed timetable, especially at a time of record inflation and soaring energy prices.

Kinder Morgan consulted with a manufacturer to determine how long it would take to retrofit the 950 Company Engines subject to the Proposed Rule that do not currently meet the emissions limits. Based on this information, and taking into account a reasonable schedule for taking units offline (to account for FERC and delivery obligations), and the timeline for required permit modifications, Kinder Morgan determined that even on a reasonably fast-paced schedule—and assuming no competition for manufacturers and no unexpected delays—it will take approximately 23 years to achieve full implementation of the Engine Proposal. The final projects would not be completed until **the year 2046**.

Kinder Morgan's ability to offer an alternative timeline (or, for that matter, alternative emissions limits or HP threshold) for the EPA's consideration is hampered, however, by EPA's decision not to identify an overall target of emission reductions. The scant data that EPA does provide, moreover, is unreliable considering EPA's failure to provide an accurate account of the number of Engines to which the Proposed Rule would apply. This, among other foundational reasons, is why Kinder Morgan proposes an alternate approach outlined in Section VI below, which would encourage states to adopt SIPs that incorporate emissions averaging for Engines and allow an Engine-by-Engine showing of economic infeasibility to ensure cost-effective application of the emissions standards.

D. Requiring Controls Only in the Ozone Season is Not Practical.

EPA's Proposed Rule proposes NO_x emissions limits "only during the ozone season" (May 1 – September 30).[89] EPA requests comments on "whether controls on . . . reciprocating IC engines are likely to be run all year (e.g., 8,760 hours/year) or only during the ozone season."[90] Requiring controls only in the ozone season does not comport with practical realities. As noted above, retrofitting existing engines with control technology is a significant, custom, costly, and time-intensive undertaking. It would not make economic sense, or further our collective goal of meaningfully reducing emissions, to only require the emissions limits during the ozone season. Installation of SCR-type controls, for example, may require accompanying modifications to the engines' combustion process for better system operations. It is therefore not a "bolt-on" technology that can be readily "idled" or temporarily removed out of the season in all

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through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant." (emphasis added)); EPA, *Guidelines for Determining Best Available Control Technology (BACT)* 4 (Dec. 1978) (stating that the determination of the weight to assign to energy, environmental, and economic impacts is a state allows "some flexibility in emission control requirements depending on local energy, environmental, and economic conditions and local preferences").

[89] Proposed Rule at 20,104; see also id. at 20,045, 20,0056, 20,177.

[90] Id. at 20,097.

circumstances. Kinder Morgan respectfully submits that given the magnitude of changes that have to be made to add control technologies, they will be run all year.

EPA defends the feasibility of the cost of the Proposed Rule in part on the assumption that EGU and non-EGU control technologies could be put into protective lay-up during non-ozone-season months.[91] But, tellingly, this assumption is derived from apparent industry practice *exclusively* with EGUs:

> 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 NOx 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.[92]

As a starting point, for the majority of Kinder Morgan's units, SCR is not the most cost-effective and technically feasible option. So, the data point EPA summarizes above is simply not relevant to the majority of Kinder Morgan's operations. Furthermore, it may be that the process for installing or uninstalling SCR technology on Kinder Morgan's units, which are non-EGU units, is not comparable to application of SCR for EGU control technologies. Converting 2SLB Engines, for example, would require a 10 ft^2 catalyst, which in many cases is so large that it can only be installed or uninstalled by crane, and then fluids like ammonia and urea must be drained before adding them back in. Those liquid compounds, in most cases, require safe handling and disposal in compliance with state and federal regulation to avoid harm to the environment. It is not within the Company's practice or protocol to unnecessarily increase the frequency of handling of products and chemicals like ammonia.

The Engine Proposal's exclusive reliance on EGU control data to justify a rule that would apply to non-EGU sources—along with the fact that is does not specifically evaluate and consider the challenges inherent in retrofitting a non-EGU Engine with the appropriate control technology—is puzzling, and calls into question the agency's understanding of the operations and businesses the agency intends to regulate. We would be happy to schedule a meeting with EPA to discuss the specific application of the control technologies to Kinder Morgan's units.

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[91] Id. at 20,078.
[92] Id.

E. Emergency Engines Must be Exempted.

The Proposed Rule does not contain an exemption for emergency Engines even though this is a standard exemption that EPA recognizes in all other relevant federal regulations.[93] Other states, including New Mexico and Colorado (and many other states), have also incorporated an exemption for emergency engines from their engine emission limits rules.[94] As EPA and states recognize, emergency engines should continue to be exempted for two primary reasons. First, their continued operation during emergencies is critical; second, precisely because they are operated only in emergencies, their emissions are minimal.

To the first, emergency engines serve a vital function in Kinder Morgan's—and other operators'—operations. When operators lose commercial power at compressor stations unexpectedly, whether as a result of inclement weather or electric grid equipment failures, they use emergency engines to sustain the most essential system needs, such as providing power for control rooms, lights, and safety and security systems, until power is restored. These systems are necessary to protect company personnel, the public, and the environment.

To the second, consistent with their limited uses, Kinder Morgan generally operates its emergency engines in only three scenarios: (i) to test the engine to ensure it is ready to operate in the event of an emergency and run periodically as necessary for maintenance; (ii) to complete an emission test; and (iii) during an emergency event. Because Kinder Morgan's emergency engines are used infrequently, they are responsible for a very limited amount of emissions. Accordingly, not exempting emergency engines would create an impediment—under threat of potential enforcement action for non-compliance—for operators to run their emergency Engines to properly respond to and redress emergency situations with minimal emission-reduction benefits.

For these reasons, any final rule, including a model rule, must exempt emergency Engines.

F. Performance Testing Every Six Months is Unreasonable.

EPA has proposed that owners and operators of stationary spark ignition Engines conduct semi-annual performance testing in accordance with 40 CFR § 60.8 to ensure that such Engines are meeting the proposed NO_x limits. This requirement would be unduly onerous. Indeed, performance testing on a single unit can cost upwards of $5,000 per test.[95] Testing Kinder Morgan's approximately 950 units twice a year would therefore cost approximately $9.5 million

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[93] See 40 C.F.R. §§ 60.4219 (defining emergency stationary internal combustion engines); 60.4248 (same); 60.4205 (designating separate compliance criteria for emergency engines); 60.4243 (same); 63.6585 ("[E]mergency stationary RICE . . . are not subject to [the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines].").

[94] 5 Colo. Code Regs. § 1001-9:E.I.C.3 ("The air pollution control technology requirements . . . do not apply to: . . . any emergency power generator . . . ."); Proposed § 20.2.50.113(B)(10) New Mexico Code of Administrative Regulations (May 6, 2021), https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2018/08/Proposed-Part-20.2.50-May-6-2021-Version.pdf ("The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part . . . .").

[95] See Exhibit 16 (showing invoices for $6,825, $5,000, and $11,950 for emissions testing).

annually,[96] with a portion of additional costs passed on to consumers in the form of higher energy prices, without a corresponding environmental benefit.

Even apart from the financial costs, testing is operationally demanding, but the Proposed Rule wholly neglects that fundamental reality. For example, per current EPA regulations, units need to be tested when the load is between 90–100% of the maximum load,[97] a state which may not occur naturally. If a unit is not at that load capacity, Kinder Morgan must take steps to artificially increase the load prior to conducting any testing—an intensive process in both labor and time. And artificially increasing the load of an engine from 60% to 90% is orders of magnitude more complex than artificially increasing the load of an engine from 85% to 90%. Flexibility in timing is therefore of paramount importance. Moreover, it is not as if Kinder Morgan can simply pick two days in the year to conduct testing on all its units at once. There is no scenario in which performance testing on hundreds of units could be conducted simultaneously. The Proposed Rule simply does not account for the fact that Kinder Morgan would need a minimum of 12 months to spread out a *single* round of performance testing on all 950 of its units. It would therefore be operationally and logistically infeasible to conduct performance testing on all the affected units within the six months allotted (five months to the extent the EPA would require one of the semi-annual tests to be conducted during the ozone season as appears to be the intent of the Proposed Rule), as would be required for semi-annual testing.

In the past, EPA *has* correctly taken note of these operational realities. Indeed, semi-annual testing is also anomalous compared to performance testing regulations on other emission sources, such as under NSPS and NESHAP, which generally require only testing every 8,760 hours of run time.[98] There is no reason to impose more frequent testing requirements than under NSPS and NESHAP.

To be clear, the existence of the above operational and financial costs does not mean that operators would be better off installing CEMS. To the contrary, the cost of installing such monitoring technology would be exorbitant, even outpacing the costs of retrofitting units. While Kinder Morgan has limited experience with CEMS, that experience is illustrative. Indeed, Kinder Morgan had to replace CEMS at a facility in 2020, incurring around $100,000 in costs just to change out the analyzers while leaving alone the hard lines. A brand new installation would

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[96] 950 x 5,000 x 2 = 9,500,000.

[97] See, e.g., 40 C.F.R § 60.4244(a) ("Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Table 2 to this subpart.").

[98] See 40 C.F.R. § 60.4243(a)(2)(iii) ("subsequent performance testing [on stationary spark ignition internal combustion engine greater than 500 HP] every 8,760 hours or 3 years, whichever comes first"); 40 C.F.R. § 60.4211(g)(3) ("subsequent performance testing [on stationary internal combustion engine greater than 500 HP] every 8,760 hours of engine operation or 3 years, which comes first"); 40 C.F.R. § 63.6615 and Table 3 to Subpart ZZZZ of Part 63 (listing subsequent performance test requirements as "every 8,760 hours or 3 years, whichever comes first" for both limited use and non-limited use existing non-emergency non-black start CI stationary RICE engines). While semi-annual testing is required for some stationary RICE engines, see 40 C.F.R. § 63.6615, the applicability of that rule is far more limited than the number of units which would be affected by this Proposed Rule. And, in any event, even that rule allowed operators to reduce the frequency of testing after two successful tests. Id.

require significant and additional resources to install electric equipment and tubing. The projected upfront installation costs are significant, and EPA should not impose any CEMS testing requirements as part of a final rule or model rule included therein.

In addition to the stand-alone costs of CEMS technology, owners and operators of facilities would also need to build shelters for the CEMS units in order to ensure a controlled environment to protect the analyzer from extreme ambient conditions such as heat, cold, dust, wind, earthquakes, and corrosive or explosive atmospheres. They would also need to build out a whole new IT framework. Nor are the costs limited to the upfront fixed costs of installing CEMS. Owners and operators would need to hire and train CEMS operators and technicians, adding ongoing labor costs and forcing Kinder Morgan to compete with other companies to attract the scarce labor force with the appropriate training to run CEMS at their facilities. This is in addition to around $15,000 in annual service costs, and $5,000 per year for cylinder rentals, all per unit.

1. Alternative Proposal to the Semi-Annual Performance Testing Requirement.

As an alternative to the EPA's proposal, Kinder Morgan suggests a testing requirement in line with the testing requirements on stationary combustion turbines. Per 40 C.F.R. § 60.4340(a), annual performance tests are required to demonstrate continuous compliance with regulations, and where a performance test is less than or equal to 75% of the NO_x emission limit for the turbine, an operator of the turbine can reduce the frequency of subsequent performance tests to once every two years. If the results of a subsequent performance test exceed 75% of the NO_x emission limit for the turbine, an operator must resume annual testing. EPA adopted this proposal in response to comments noting that the sophisticated controls on lean premix turbines will provide consistent NO_x emission results,[99] just as controls anticipated to be installed at Kinder Morgan's units, combined with the quality of FERC-regulated gas in the transmission sector, ensures consistent NO_x emission results.

Here too, Kinder Morgan proposes that EPA allow for annual testing on Engines, with an opportunity to reduce the frequency of testing to every two years if testing shows that NO_x emissions are equal to 75% or less of permitted NO_x emissions limits. Whatever testing frequency EPA chooses it should, at the very least, provide an opportunity to reduce the frequency of testing if testing shows that NO_x emissions are equal to 75% or less of permitted NO_x emission limits. If semi-annual testing is not selected, EPA could work with INGAA and other industry members to develop reasonable best management practices for Engine operation and maintenance.

EPA should also include an option for portable testing. Use of portable gas analyzers equipped with electrochemical sensors has already been approved as an alternative method for determination of Oxygen, Carbon Monoxide, and Nitrogen Oxides from stationary sources for use at (1) Industrial/Commercial/Institutional Steam Generating Units subject to 40 CFR Part 60,

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[99] See Dkt. No. EPA-HQ-OAR-2004-0490-0322, *Response to Public Comments on Proposed Standards of Performance for Stationary Combustion Turbines*, 88 (July 6, 2006).

Subpart Db; (2) stationary spark ignition internal combustion engines subject to 40 CFR Part 60, Subpart JJJJ; and (3) RICE subject to 40 CFR Part 63, Subpart ZZZZ. This method leverages the inherent linear performance of electrochemical cell-based technology to provide simplified procedures that lower costs.[100] There is no reason not to allow Engine owners and operators flexibility to employ this proven cost-effective and reliable method of performance testing.

G. <u>As Proposed, the Engine Proposal Will Significantly Disrupt the Distribution of Energy in the United States.</u>

Given the scale of the undertaking to retrofit approximately 950 units in order to comply with the Proposed Rule before the May 2026 deadline, a large-scale reduction in output of natural gas is unavoidable. The very few manufacturers capable of retrofitting units would be at capacity working on Kinder Morgan's Engines alone, let alone the thousands of additional units from other natural gas suppliers operating in the same regions. The backlog will inevitably result in Engines remaining offline for extended periods of time and could potentially jeopardize the safe and reliable transmission of natural gas in the United States and/or could lead to higher costs for transporting gas, which costs are ultimately passed along from the transmission companies to customers, the local distribution companies, and large end users, to their customers: the consumers. Under EPA's unreasonable 2026 timetable, Engines will have to be idled until the retrofitting is complete and millions of end-users of natural gas could face periodic outages along with higher energy bills.

Moreover, EPA should consider that these impacts are likely to harm already disadvantaged communities including low-income communities and communities of color. Research has documented that households at or near the Federal Poverty Level are significantly more burdened by energy insecurity (and therefore impacted more by scarcity and higher prices) than other socioeconomic groups.[101] Researchers have shown that poor communities face worse health outcomes and worse educational outcomes in part due to energy insecurity.[102] A 2019 study found that low-income households in U.S. cities spend on average 10–20% of their income on energy bills.[103] Previous research has also shown that subsidized housing recipients face an increased burden from outages because they are more likely to rent from private landlords who

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[100] Portable Analyzer Test Method Update for Common Analyzers Phase 3 Report, Innovative Environmental Solutions, Inc., for the Pipeline Research Council International, Inc., Catalog PR-312-17204-R01 (Oct. 10, 2017), https://www.prci.org/Research/CompressorPumpStation/CPSProjects/CPS-11 6A/3241/136252/125634.aspx.

[101] Jessel et al. *Energy, poverty, and health in climate change: a comprehensive review of an emerging literature*. Frontiers in Public Health, 357 (2019), Frontiers | Energy, Poverty, and Health in Climate Change: A Comprehensive Review of an Emerging Literature | Public Health (frontiersin.org).

[102] <u>See generally</u> <u>id.</u>

[103] Kontokosta et al. *Energy cost burdens for low-income and minority households: Evidence from energy benchmarking and audit data in five US cities*, Journal of the American Planning Association, 86(1), at 95 (2020).

neither weatherize nor optimize energy efficiency due to upfront costs.[104] Likewise, communities of color are also disproportionally affected by energy insecurity.[105]

EPA's Proposed Rule therefore will exacerbate harm to disproportionately impacted communities by creating energy shortages and corresponding increases in energy prices that historically have not been equally distributed.

VI. ALTERNATE PROPOSAL: EPA'S APPROACH SHOULD MODEL PAST SUCCESSFUL PRACTICE TO INFORM ANY NEWLY PROPOSED RULE

In summary, and following successful precedent, EPA must establish emissions targets for each state, and should publish a model rule (with core elements described below) and allow states to exercise their discretion to implement the model rule or other cost-effective and technically feasible rules through SIP implementation.

A. Summary of 1998 NO_x SIP Call and Subsequent Developments

In 1998, EPA issued the "NO_x SIP Call,"[106] requiring 23 states (including the District of Columbia) to reduce their NO_x emissions in an attempt to reduce interstate ozone pollution based on the Good Neighbor Provision. Under the NO_x SIP Call, EPA established emissions "budgets" for each state, designating the acceptable level of NO_x emissions from that jurisdiction and a model cap and trade program that allowed sources to buy and sell emissions allowances. Following litigation, the D.C. Circuit struck down portions of the NO_x SIP Call, remanding back to the EPA for further rulemaking.[107]

Following consultation with stakeholders, EPA came back with the 2004 NO_x SIP Call Phase 2 rule ("2004 NO_x Rule"). The 2004 NO_x Rule required 21 States and the District of Columbia again set NO_x budgets for states to eliminate those amounts of NO_x emissions that contribute significantly to downwind nonattainment of the 1-hour ozone standard. The implementation of the 2004 NO_x Rule, moreover, relied on emission averaging provisions:

> States may establish a NO_x tons/season emissions decrease target for individual companies and then provide the companies with the opportunity to develop a plan that would achieve the needed emissions reductions. The companies may select from a variety of control measures to apply at their various emission units in the State or portion of the State affected under the NO_x SIP call. . . . What is important from EPA's perspective is that the State, through a SIP revision, demonstrate that

[104] Hernández & Bird, *Energy burden and the need for integrated low-income housing and energy policy*, Poverty Public Policy, 2(4), at 5-25 (2010).
[105] Jessel, supra note 101.
[106] 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 Fed. Reg. 57,356 (Oct. 27, 1998) [hereinafter "NOx SIP Call"].
[107] See Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000).

all the control measures contained in the SIP are collectively adequate to provide for compliance with the State's NO_x budget during the 2007 ozone season.[108]

EPA coupled this flexible averaging approach with the development of a model rule that states could adopt as part of their SIPs. The model rule gave companies credit towards their individualized compliance plan for decreases in NO_x emissions from engines that were not even subject to the 2004 NO_x Rule.[109] Amongst other advantages, the averaging approach relieved the EPA, state agencies, and regulated companies of the difficulty of agreeing on technical definitions for lean-burn and rich-burn engines, obviated the need to determine whether individual engines could in fact achieve certain control levels with a prescribed control technology, and allowed companies and states to achieve compliance with NO_x SIP Call requirements with minimal deleterious impact on natural gas capacity and operational reliability.[110]

This 2004 NO_x Rule emission averaging approach has led to significant emission reductions. Indeed, in light of EPA's successful implementation of the emissions averaging approach in the 2004 NO_x Rule, individual states have recognized these advantages and incorporated averaging into their own rulemakings.[111] EPA should therefore follow the same approach here.

B. <u>Although Each State Should Be Afforded Discretion to Develop an Effective SIP, as a Part of this Proposed Rule, EPA Should Develop a Model Rule To Encourage States to Adopt SIPs that Incorporate Emissions Averaging for RICE and an Engine-by-Engine Showing of Economic Infeasibility.</u>

1. EPA's Model Rule Should Adopt Emissions Averaging as it Did in the 2004 NO_x Rule.

Kinder Morgan recommends that EPA adopt the emissions averaging approach it incorporated in the 2004 NO_x Rule and as proposed by INGAA in its comments on the Proposed Rule. As EPA recognized in promulgating the 2004 NO_x Rule, averaging is a reasonable compliance flexibility mechanism that allows for the achievement of emissions limitations with reduced impacts on cost, natural gas capacity, and operational reliability.[112] Specifically, averaging provides enforceable and verifiable measures to control engines without operators having to work through the technical confusion of the definitions of lean- and rich-burn engines or determine whether individual engines can achieve certain emissions limitations with the

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[108] Memorandum from Lydia N. Wegman, "State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NOx) – Stationary Reciprocating Internal Combustion Engines" (Aug. 22, 2002) at 2, https://archive.epa.gov/ttn/ozone/web/pdf/ic_engine_guidance_memo_8_22_2002.pdf.
[109] EPA Model Rule § 3(a)(5).
[110] <u>See</u> 69 Fed. Reg. 21,604, 21,621 (Apr. 21, 2004) (discussing additional rationales for emissions averaging in comments on what became the 2004 NOx Rule).
[111] <u>See, e.g.</u>, 25 Pa. Code § 129.98(a) ("[A] major NOx emitting facility . . . that cannot meet the applicable NOx RACT emission limitation may elect to meet the applicable NOx RACT emission limitation . . . by averaging NOx emissions on either a facility-wide or system-wide basis using a 30-day rolling average").
[112] <u>See</u> 69 Fed. Reg. 21,604, 21,621 (Apr. 21, 2004).

prescribed control technologies. Additionally, emission averaging will help address the problem presented by achieving compliance on engines that are technically impossible to retrofit, as discussed in detail above. Because an averaging approach allows more regulatory flexibility while still achieving significant emissions reductions, it is a sensible policy that should be incorporated into the model rule. Indeed, many states, including Illinois, New York, Ohio, Pennsylvania, New Mexico, Colorado, and Texas have already incorporated emissions averaging into their approaches to reducing NO_x emissions. In short, EPA should follow its own past approach—as well as those taken in other states—to incorporate this reasonable and sound regulatory approach into any final rule adopted here.

Kinder Morgan further adopts and incorporates by reference comments submitted by INGAA that address emissions averaging at the company level.

2. EPA's Model Rule Must Expressly Incorporate a RACT Analysis on an Engine-by-Engine Basis to Determine the Cost-Effective Application of the Emissions Standards.

The model rule that Kinder Morgan proposes should include the option for owners and operators to show—on an Engine-by-Engine basis—that attaining the specific emissions rate limit would be economically infeasible. This option should be available before calculating the emissions reductions required under an averaging approach because it will ensure the model rule can be reasonably implemented by regulated companies. Installing additional controls for certain types of Engines could be prohibitively expensive, even with averaging. Therefore, the model rule must also incorporate a RACT analysis on an engine-by-engine basis to determine a cost-effective application of the emissions standards. Under this approach, an owner or operator could be relieved of the obligation to comply with the proposed emissions limitations applicable to a particular existing Engine, upon a showing (and determination by the state) that compliance would be technically impracticable or economically infeasible, similar to the requirements EPA has established for RACT. For example, under RACT:

> The determination of RACT and the corresponding emission rate, ensuring the proper application and operation of RACT, may vary from source to source due to source configuration, retrofit feasibility, operation procedures, raw materials, and other technical or economic characteristics of an individual source or group of sources.[113]

As discussed above in Section V.A, SCR is frequently the only control option for some engines to comply with the emissions-limit standards contemplated by the EPA. Yet, as Kinder Morgan also discussed above, Kinder Morgan's detailed cost case studies for the addition of various control technologies on some of its Engines range from \$157,709 to \$6,434,942. Converting these capital costs to costs per ton of emissions abatement demonstrates the economic unreasonableness of such controls. Whereas such retrofits would cost from \$1,000 to \$684,169

[113] EPA, *Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas* 2 (Dec. 9, 1976).

on a per-ton basis (assuming reasonable average run-time over a five-year period), the Proposed Rule identifies a cost reasonableness threshold of $7,500 per ton of emissions abated by non-EGUs. Although $7,500 per ton is higher than what other NO_x rules have used as the cost-effective threshold, it could be an appropriate cost threshold for reasonableness if it is adequately substantiated in the rulemaking record. At minimum, $7,500 per ton reduced must be considered a "not to exceed" threshold, which would be consistent with other similar state-level rulemakings.[114] In turn, any model rule for states should be updated to contemplate that in some circumstances, engines will not be able to reduce emissions at this cost threshold. Therefore, an engine-by-engine approach is merited and would provide an additional cost backstop for the aggressive emissions reductions that the Proposed Rule aims to achieve.

Including such an option is especially important given the Proposed Rule's own acknowledgment that the cost effectiveness-analysis performed by EPA using CoST was "designed to be used for illustrative control strategy analyses . . . and **not for unit-specific, detailed engineering analyses**."[115] Thus, the Proposed Rule acknowledges that unit-specific, engineering analyses are likely to reveal different costs for control technologies employed on a particular unit. Moreover, the EPA's definition of RACT evaluates what a "a **particular** source is capable of meeting,"[116] and thereby contemplates a particularized (i.e., case-by-case) approach for determining the reasonableness of a control technology given the circumstances.

Kinder Morgan proposes that regulated entities be allowed to demonstrate—through a unit-specific, detailed engineering analysis like the one contemplated by the Proposed Rule and EPA's RACT definition—that the cost to achieve the emissions rate limits would require costs above the $7,500 threshold, and therefore not economically feasible. Kinder Morgan also proposes that the appropriate state regulator would review the engineering analysis to verify that conclusion. If the cost is verified to be above the $7,500 threshold, then the engine would be exempted from compliance, and its contribution to total emissions would be subtracted out from any total emissions reductions required under an emissions averaging approach a compliance option incorporating emissions averaging. States where Kinder Morgan has participated in rulemakings have adopted such an approach,[117] and it safeguards against unreasonably high, if not prohibitive, compliance costs.

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[114] See supra note 44.

[115] Proposed Rule at 20,089 (emphasis added). See also id. at 20,090 ("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.").

[116] 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979) (emphasis added); see also Michigan v. EPA, 805 F.2d 176, 180 (6th Cir. 1986) ("Since 1976, the EPA has interpreted [RACT] to be 'the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.'").

[117] For example, in New Mexico, the New Mexico Environmental Improvement Board ("EIB") has approved both an emissions averaging approach through an Alternative Compliance Plan and an Alternative Emissions Standard for individual units. The EIB is in the process of finalizing the rules and publishing them to the New Mexico Register.

VII. CONCLUSION

Kinder Morgan appreciates the opportunity to submit these comments. As a fundamental concern and fatal flaw to its proposal, EPA is relying on an extraordinarily inaccurate set of data in support of the Engine Proposal, which undermines the entire proposal. In fact, the agency has underestimated the number of subject Engines at such a significant magnitude that it has in turn dramatically underestimated the anticipated emissions by at least half. Not only is reliance on this inaccurate data unlawful rulemaking, but the rule itself results in over-control of emissions, contrary to the CAA and court precedent. EPA cannot proceed with this rulemaking and must re-publish a proposed draft rule with updated and accurate data and transparent analysis.

If EPA pursues a new draft proposed rule, with a renewed public comment period, Kinder Morgan respectfully requests the agency consider and address each of the following concerns raised:

- EPA overestimates the technical feasibility involved with the proposed emissions limits. The technologies available are limited when applied to certain types of engines, and even after applying available control technologies, the emission limits may not be achievable.
- Even if the control technologies are technically feasible, achieving the standard could nonetheless be cost-prohibitive, and well in excess of EPA's cost threshold of $7,500 per ton of NO_x reduced in many cases.
- The proposed timeline for compliance is unreasonable if not impossible.
- EPA does not appear to recognize that controls cannot be installed just for the ozone season, an assumption that further exacerbates concerns around over-control.
- Emergency engines must be exempted.
- The semi-annual testing requirements are onerous, unnecessary, and do not consider the operational realities faced by the Pipeline Transportation of Natural Gas industry. A revised approach consistent with current regulatory programs is appropriate.

In support of these comments, Kinder Morgan conducted extensive analyses of its existing Engine data, relevant control technologies, and actual cost-estimates. The results summarized herein indicate that a one-size-fits all emissions standards across 23 states is not the appropriate avenue for cost-effective emissions reductions to address potential ozone transport. Instead, based on its data and Kinder Morgan's extensive experience in numerous states already implementing NO_x emissions reduction programs for large engines, Kinder Morgan encourages EPA to adopt a model rule that incorporates emissions averaging for Engines on a state-by-state basis, as well as an Engine-by-Engine showing of economic infeasibility, among other considerations described above. We recognize the complexities and challenges around the relevant data and analysis, and the Company welcomes further engagement with EPA on this matter.

Sincerely,

Michael Pitta
Vice President of EHS

(enclosures)

EXHIBITS LIST

Exhibit 1 – Example Cost of 2SLB SCR Addition
Exhibit 2 – Example Cost of 2SLB SCR Addition
Exhibit 3 – Example Cost of 2SLB Combustion Modifications
Exhibit 4 – Example Cost of 2SLB Combustion Modifications
Exhibit 5 – Example Cost of 2SLB Combustion Modifications
Exhibit 6 – Example Cost of 2SLB Combustion Modifications
Exhibit 7 – Example Cost of 4SLB SCR Addition
Exhibit 8 – Example Cost of 4SLB Combustion Modifications
Exhibit 9 – Example Cost of 4SLB Combustion Modifications
Exhibit 10 – Example Cost of 4SLB Combustion Modifications
Exhibit 11 – Example Cost of 4SLB Unit Replacement
Exhibit 12 – Example Cost of 4SRB NSCR and Combustion Modifications
Exhibit 13 – Example Cost of 4SRB NSCR and AFRC
Exhibit 14 – Example Cost of 4SRB AFRC
Exhibit 15 –Vendor Letter Regarding SCR Cost Increase
Exhibit 16 – Emissions Testing Invoices

EXHIBIT 1

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.	[redacted]	ORIGINAL EST. DATE	04/21/20
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	13.56%
PROJECT MANAGER	[redacted]	[redacted]	
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	Oct-23
		ESTIMATE ACCURACY LEVEL	Class 3

Emission Control System SCOPE: SCR Emissions control system provided by [redacted]. This cost is a per unit cost

New Aux SCOPE: Install new AUX building and Air Compressor to be used for SCR Installation on all five units

ASSET CAPABILITIES:	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics: Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Emission Control System	New Aux			TOTAL
MATERIAL (INCL SALES TAX)	$ 895,400	$ 883,300			$ 1,778,700
COMPANY LABOR COST	$ 92,900	$ 55,800			$ 148,700
PM, ENG, LAND, ENVIRO - EXPENSE	$ 10,800	$ 5,400			$ 16,200
PRIMARY CONSTRUCTION CONTRACTOR	$ 967,000	$ 1,116,100			$ 2,083,100
SECONDARY CONTRACTOR	$ 16,200	$ -			$ 16,200
PROFESSIONAL ENGINEERING	$ 265,500	$ 180,700			$ 446,200
INSPECTION SERVICES	$ 169,100	$ 91,300			$ 260,400
RADIOGRAPHY SERVICES	$ 3,800	$ 1,900			$ 5,700
ENVIRONMENTAL CONTRACTOR	$ 54,100	$ 27,000			$ 81,100
ELECTRICAL & INSTRUMENTATION	$ -	$ -			$ -
RIGHT OF WAY CONTRACTOR	$ -	$ -			$ -
SURVEY CONTRACTOR	$ 31,800	$ 47,700			$ 79,500
OUTSIDE LEGAL SERVICES	$ 28,400	$ 16,600			$ 45,000
ROW & DAMAGES	$ 12,500	$ 5,000			$ 17,500
PERMIT FEES	$ -	$ -			$ -
GAS LOSS	$ 6,700	$ -			$ 6,700
SUBTOTAL	$ 2,554,200	$ 2,430,800			$ 4,985,000
CONSTRUCTION CONTINGENCY	$ 255,420	$ 243,080			$ 498,500
AFUDC	$ 78,464	$ 73,396			$ 151,859
SUBTOTAL	$ 2,888,084	$ 2,747,276			$ 5,635,359
CAPITALIZED OVERHEAD (BURDEN)	$ -	$ -			$ -
TAX GROSS-UP	$ -	$ -			$ -
ESCALATION	$ -	$ -			$ -
RISK INSURANCE	$ -	$ -			$ -
ESTIMATED TOTAL COST	**$ 2,888,084**	**$ 2,747,276**			**$ 5,635,359**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Oct-23	Oct-23	Oct-23	Oct-23	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

EXHIBIT 2

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.	[redacted]	ORIGINAL EST. DATE	09/08/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	13.17%
PROJECT MANAGER	[redacted]	[redacted]	
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	Oct-23
		ESTIMATE ACCURACY LEVEL	Class 3

Emission Control System SCOPE: SCR Emissions control system provided by [redacted]. This cost is a per unit cost. Cost developed per approved estimate CE2004034

Aux Building SCOPE: Install new AUX building and Air Compressor to be used for SCR Installation. Cost developed per approved estimate CE2004034

ASSET CAPABILITIES: Vol @ ### psi

			Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

			Emission Control System	Aux Building	TOTAL
MATERIAL (INCL SALES TAX)			$ 676,100	$ 650,400	$ 1,326,500
COMPANY LABOR COST			$ 71,200	$ 44,800	$ 116,000
PM, ENG, LAND, ENVIRO - EXPENSE			$ 3,000	$ 2,800	$ 5,800
PRIMARY CONSTRUCTION CONTRACTOR			$ 1,187,800	$ 678,900	$ 1,866,700
SECONDARY CONTRACTOR			$ 1,272,000	$ -	$ 1,272,000
PROFESSIONAL ENGINEERING			$ 198,700	$ 183,800	$ 382,500
INSPECTION SERVICES			$ 265,300	$ 68,000	$ 333,300
RADIOGRAPHY SERVICES			$ 3,700	$ 2,800	$ 6,500
ENVIRONMENTAL CONTRACTOR			$ 33,700	$ 20,200	$ 53,900
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ 21,200	$ 21,200
SURVEY CONTRACTOR			$ 10,700	$ 10,700	$ 21,400
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ 15,000	$ 15,000	$ 30,000
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ 9,600	$ -	$ 9,600
SUBTOTAL			$ 3,746,800	$ 1,698,600	$ 5,445,400
CONSTRUCTION CONTINGENCY			$ 374,680	$ 169,860	$ 544,540
AFUDC			$ 98,547	$ 126,664	$ 225,211
SUBTOTAL			$ 4,220,027	$ 1,995,124	$ 6,215,151
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 4,220,027**	**$ 1,995,124**	**$ 6,215,151**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Oct-23	Oct-23	Oct-23	Oct-23	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

EXHIBIT 3

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.	[redacted]	ORIGINAL EST. DATE	08/02/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	0.00%
PROJECT MANAGER	[redacted]	[redacted]	
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY	[redacted]	PROJECT TYPE	Sustaining Capital
		IN-SERVICE	May-24
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Install new combustion modification equipment (pre-combustion chambers), ancillary hardware, and automation on 4-Cooper GMVA10 compressor units at [redacted]

CWIP SCOPE: Isolate and tear down compressor driver and exhaust on 4-Cooper GMVA10 compressor units [redacted] Prep for installation of new combustion modification equipment (pre-combustion chambers), ancillary hardware, and automation.

ASSET CAPABILITIES: Vol @ ### psi

			Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 10,937,100	$ 10,937,100
COMPANY LABOR COST			$ -	$ 161,900	$ 161,900
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 23,100	$ 23,100
PRIMARY CONSTRUCTION CONTRACTOR			$ 120,000	$ 1,230,500	$ 1,350,500
SECONDARY CONTRACTOR			$ 10,000	$ 910,000	$ 920,000
PROFESSIONAL ENGINEERING			$ -	$ 58,500	$ 58,500
INSPECTION SERVICES			$ 9,000	$ 178,600	$ 187,600
RADIOGRAPHY SERVICES			$ -	$ 1,800	$ 1,800
ENVIRONMENTAL CONTRACTOR			$ -	$ 15,000	$ 15,000
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ -	$ -
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 139,000	$ 13,516,500	$ 13,655,500
CONSTRUCTION CONTINGENCY			$ 13,900	$ 1,351,650	$ 1,365,550
AFUDC			$ -	$ 412,485	$ 412,485
SUBTOTAL			$ 152,900	$ 15,280,635	$ 15,433,535
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 152,900**	**$ 15,280,635**	**$ 15,433,535**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	May-24	May-24	May-24	May-24	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager		
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

[redacted]

EXHIBIT 4

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.	CE2109038	ORIGINAL EST. DATE	11/02/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	0.00%
PROJECT MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY	[redacted]	PROJECT TYPE	Sustaining Capital
		IN-SERVICE	Nov-25
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Removal of existing equipment for retrofit

CWIP SCOPE: Retrofits to meet proposed standards for existing reciprocating unit [redacted] using combustion modifications (PCCs, turbochargers, control panel upgrade, etc., as needed) and oxidation catalyst. All ancillaries and infrastructure must be considered and modified as needed to support the engine modifications for ongoing compliant operation.

ASSET CAPABILITIES:	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 3,172,100	$ 3,172,100
COMPANY LABOR COST			$ -	$ 161,900	$ 161,900
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 23,100	$ 23,100
PRIMARY CONSTRUCTION CONTRACTOR			$ 64,700	$ 680,300	$ 745,000
SECONDARY CONTRACTOR			$ 10,800	$ 981,900	$ 992,700
PROFESSIONAL ENGINEERING			$ -	$ 50,500	$ 50,500
INSPECTION SERVICES			$ 4,800	$ 69,800	$ 74,600
RADIOGRAPHY SERVICES			$ -	$ 1,900	$ 1,900
ENVIRONMENTAL CONTRACTOR			$ -	$ 16,200	$ 16,200
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ -	$ -
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 80,300	$ 5,157,700	$ 5,238,000
CONSTRUCTION CONTINGENCY			$ 8,030	$ 511,300	$ 519,330
AFUDC			$ -	$ 146,569	$ 146,569
SUBTOTAL			$ 88,330	$ 5,815,569	$ 5,903,899
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 88,330**	**$ 5,815,569**	**$ 5,903,899**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Nov-25	Nov-25	Nov-25	Nov-25	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates $FV=PV(1+i)^n$	
Material:	0.0%
Other:	0.0%

[redacted]

EXHIBIT 5

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	08/24/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	13.26%
PROJECT MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	May-24
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Removal of existing equipment to be replaced.

CWIP SCOPE: This unit is a 2SLB unit that needs to meet 3 g/hp-hr of NOx. To achieve this a the turbocharger will need to be re-aeroed and ePCC's added.

ASSET CAPABILITIES:	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics: Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 841,800	$ 841,800
COMPANY LABOR COST			$ -	$ 55,800	$ 55,800
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 3,200	$ 3,200
PRIMARY CONSTRUCTION CONTRACTOR			$ 162,400	$ 682,700	$ 845,100
SECONDARY CONTRACTOR			$ -	$ 3,139,300	$ 3,139,300
PROFESSIONAL ENGINEERING			$ -	$ 157,000	$ 157,000
INSPECTION SERVICES			$ 29,600	$ 221,900	$ 251,500
RADIOGRAPHY SERVICES			$ -	$ 4,700	$ 4,700
ENVIRONMENTAL CONTRACTOR			$ -	$ 21,700	$ 21,700
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ 10,000	$ 10,000
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 192,000	$ 5,138,100	$ 5,330,100
CONSTRUCTION CONTINGENCY			$ 19,200	$ 513,810	$ 533,010
AFUDC			$ -	$ 79,699	$ 79,699
SUBTOTAL			$ 211,200	$ 5,731,609	$ 5,942,809
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 211,200**	**$ 5,731,609**	**$ 5,942,809**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	May-24	May-24	May-24	May-24	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

EXHIBIT 6

2SLB Turbo & PCC Installation

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	**COMPANY NO.**	[redacted]
REQUESTED BY	[redacted]	**PREPARED BY**	
ESTIMATE NO.		**ORIGINAL EST. DATE**	06/04/22
REVISION NO.	BASE	**CONSTRUCTION CONTINGENCY**	10%
REVISION DATE		**OVERHEAD**	0.00%
PROJECT MANAGER		[redacted]	
STATE	[redacted]	**TAX GROSS UP**	0.00%
COUNTY		**PROJECT TYPE**	Sustaining Capital
		IN-SERVICE	Nov-25
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Removal of existing equipment for retrofit

CWIP SCOPE: Retrofits to meet proposed standards for existing reciprocating unit [redacted] using combustion modifications (PCCs, turbochargers, control panel upgrade, etc., as needed) and oxidation catalyst. All ancillaries and infrastructure must be considered and modified as needed to support the engine modifications for ongoing compliant operation.

ASSET CAPABILITIES: Vol @ ### psi

	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 4,004,900	$ 4,004,900
COMPANY LABOR COST			$ -	$ 161,900	$ 161,900
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 23,100	$ 23,100
PRIMARY CONSTRUCTION CONTRACTOR			$ 64,200	$ 674,600	$ 738,800
SECONDARY CONTRACTOR			$ 10,700	$ 973,700	$ 984,400
PROFESSIONAL ENGINEERING			$ -	$ 50,100	$ 50,100
INSPECTION SERVICES			$ 4,800	$ 69,200	$ 74,000
RADIOGRAPHY SERVICES			$ -	$ 1,900	$ 1,900
ENVIRONMENTAL CONTRACTOR			$ -	$ 16,100	$ 16,100
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ -	$ -
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 79,700	$ 5,975,500	$ 6,055,200
CONSTRUCTION CONTINGENCY			$ 7,970	$ 597,550	$ 605,520
AFUDC			$ -	$ 178,543	$ 178,543
SUBTOTAL			$ 87,670	$ 6,751,593	$ 6,839,263
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 87,670**	**$ 6,751,593**	**$ 6,839,263**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Nov-25	Nov-25	Nov-25	Nov-25	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

[redacted]

EXHIBIT 7

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	09/08/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	13.10%
PROJECT MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	Oct-23
		ESTIMATE ACCURACY LEVEL	Class 3

Emission Control System SCOPE: SCR Emissions control system provided by [redacted] This cost is a per unit cost.

Aux Building SCOPE: Install new AUX building and Air Compressor to be used for SCR Installation.

ASSET CAPABILITIES:	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

			Emission Control System	Aux Building	TOTAL
MATERIAL (INCL SALES TAX)			$ 687,900	$ 661,800	$ 1,349,700
COMPANY LABOR COST			$ 71,200	$ 44,800	$ 116,000
PM, ENG, LAND, ENVIRO - EXPENSE			$ 3,000	$ 2,800	$ 5,800
PRIMARY CONSTRUCTION CONTRACTOR			$ 1,208,600	$ 690,800	$ 1,899,400
SECONDARY CONTRACTOR			$ 1,294,300	$ -	$ 1,294,300
PROFESSIONAL ENGINEERING			$ 202,200	$ 187,000	$ 389,200
INSPECTION SERVICES			$ 269,900	$ 69,200	$ 339,100
RADIOGRAPHY SERVICES			$ 3,800	$ 2,800	$ 6,600
ENVIRONMENTAL CONTRACTOR			$ 34,300	$ 20,600	$ 54,900
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ 21,600	$ 21,600
SURVEY CONTRACTOR			$ 10,800	$ 10,800	$ 21,600
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ 15,000	$ 15,000	$ 30,000
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ 9,600	$ -	$ 9,600
SUBTOTAL			$ 3,810,600	$ 1,727,200	$ 5,537,800
CONSTRUCTION CONTINGENCY			$ 381,060	$ 172,720	$ 553,780
AFUDC			$ 100,167	$ 128,696	$ 228,863
SUBTOTAL			$ 4,291,827	$ 2,028,616	$ 6,320,443
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 4,291,827**	**$ 2,028,616**	**$ 6,320,443**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Oct-23	Oct-23	Oct-23	Oct-23	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

EXHIBIT 8

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	08/24/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	12.97%
PROJECT MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	Oct-23
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Removal of existing equipment to be replaced.

CWIP SCOPE: This unit is a 4SLB Ingersoll-Rand KVS-412 unit that will need to meet 1.5 g/hp-hr Nox. To achieve this reduction high pressure fuel and ePCC's will need to be added plus the turbocharger re-aeroed.

ASSET CAPABILITIES: Vol @ ### psi

			Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 1,288,300	$ 1,288,300
COMPANY LABOR COST			$ -	$ 55,800	$ 55,800
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 3,200	$ 3,200
PRIMARY CONSTRUCTION CONTRACTOR			$ 162,400	$ 684,000	$ 846,400
SECONDARY CONTRACTOR			$ -	$ 3,085,100	$ 3,085,100
PROFESSIONAL ENGINEERING			$ -	$ 157,000	$ 157,000
INSPECTION SERVICES			$ 29,600	$ 221,900	$ 251,500
RADIOGRAPHY SERVICES			$ -	$ 4,700	$ 4,700
ENVIRONMENTAL CONTRACTOR			$ -	$ 21,700	$ 21,700
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ 10,000	$ 10,000
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 192,000	$ 5,531,700	$ 5,723,700
CONSTRUCTION CONTINGENCY			$ 19,200	$ 553,170	$ 572,370
AFUDC			$ -	$ 138,872	$ 138,872
SUBTOTAL			$ 211,200	$ 6,223,742	$ 6,434,942
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 211,200**	**$ 6,223,742**	**$ 6,434,942**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	Oct-23	Oct-23	Oct-23	Oct-23	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director	[redacted]	
			Project Controls	[redacted]	
			Vice President	[redacted]	

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

[redacted]

EXHIBIT 9

4SLB Clean Burn Modification

KINDER MORGAN - MIDSTREAM

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	06/09/22
REVISION NO.	1.0	CONSTRUCTION CONTINGENCY	10.0%
REVISION DATE	06/09/22	OVERHEAD	16.0%
PROJ MANAGER	[redacted]	[redacted]	[redacted]
[redacted]		GROSS UP	9.0%

SCOPE

CAT Low emissions kit SCOPE:	Installation cleanburn modifications to Caterpillar unit with serial number starting with 4EK, as well as miscellaneous ancillary equipment to allow unit to meet 1.5 g/hp-hr NOx limit required by the Good Neighbor Rule.
Tab 2 SCOPE:	
Tab 3 SCOPE:	
Tab 4 SCOPE:	
Tab 5 SCOPE:	

ASSET CAPABILITIES:

ESTIMATE SUMMARY

	CAT Low emissions	Tab 2	Tab 3	Tab 4	Tab 5	TOTAL
PIPE	$ -					$ -
VALVES	$ -					$ -
FITTINGS	$ -					$ -
MEASUREMENT EQUIPMENT	$ -					$ -
EFM & SCADA	$ -					$ -
COMPRESSION EQUIPMENT	$ 241,516					$ 241,516
PROCESS / TREATING EQUIPMENT	$ -					$ -
PRESSURE VESSELS	$ -					$ -
DIRECT FIRED HEATERS	$ -					$ -
HEAT EXCHANGERS	$ -					$ -
TANKS	$ -					$ -
PUMPS	$ -					$ -
PLC HARDWARE / SOFTWARE	$ -					$ -
MISC MATERIALS & SUPPLIES	$ -					$ -
TOTAL MATERIAL COST	**$ 241,516**					**$ 241,516**
TOTAL COMPANY COST	**$ 11,760**					**$ 11,760**
PIPELINE CONSTRUCTION CONTRACTOR	$ -					$ -
FACILITY CONSTRUCTION CONTRACTOR	$ -					$ -
TOTAL CONSTRUCTION COST	**$ -**					**$ -**
PROFESSIONAL ENGINEERING	$ 10,000					$ 10,000
INSPECTION SERVICES	$ 11,916					$ 11,916
RADIOGRAPHY SERVICES	$ -					$ -
ENVIRONMENTAL CONTRACTOR	$ -					$ -
ELECTRICAL & INSTRUMENTATION	$ 16,323					$ 16,323
RIGHT OF WAY CONTRACTOR	$ -					$ -
SURVEY CONTRACTOR	$ -					$ -
OUTSIDE LEGAL SERVICES	$ -					$ -
TOTAL OUTSIDE SERVICES	**$ 38,239**					**$ 38,239**
ROW & DAMAGES	$ -					$ -
PERMITTING	$ -					$ -
GAS LOSS	$ -					$ -
SUBTOTAL	**$ 291,515**					**$ 291,515**
CONSTRUCTION CONTINGENCY	$ 29,152					$ 29,152
AFUDC	$ 1,463					$ 1,463
SUBTOTAL	**$ 322,130**					**$ 322,130**
CAPITALIZED OVERHEAD (BURDEN)	$ -					$ -
TAX GROSS UP	$ -					$ -
GROSS ESTIMATED COST	**$ 322,130**					**$ 322,130**

ASSUMPTIONS

Include (Yes/No)	Assumptions
Yes	See Scoping Tab

Revision	Date	Notes	Approval	Name	Date
			PM	[redacted]	1/27/2021
			Director	[redacted]	
			VP	[redacted]	

AUTHORITY LEVELS:	
< $100,000	PROJECT MANAGER
$100,000 to $5,000,000	MANAGER
> $5,000,000	DIRECTOR AND VP

[redacted]

[redacted]

EXHIBIT 10

KINDER MORGAN - MIDSTREAM

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	06/09/22
REVISION NO.	1.0	CONSTRUCTION CONTINGENCY	10.0%
REVISION DATE	06/09/22	OVERHEAD	16.0%
PROJ MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted] COUNTY [redacted]	GROSS UP	9.0%

SCOPE

CAT Low emissions kit SCOPE:	Installation cleanburn modifications to Caterpillar unit, as well as miscellaneous ancillary equipment to allow unit to meet 1.5 g/hp-hr NOx limit required by the Good Neighbor Rule.
Tab 2 SCOPE:	
Tab 3 SCOPE:	
Tab 4 SCOPE:	
Tab 5 SCOPE:	

ASSET CAPABILITIES:

ESTIMATE SUMMARY

	CAT Low emissions	Tab 2	Tab 3	Tab 4	Tab 5	TOTAL
PIPE	$ -					$ -
VALVES	$ -					$ -
FITTINGS	$ -					$ -
MEASUREMENT EQUIPMENT	$ -					$ -
EFM & SCADA	$ -					$ -
COMPRESSION EQUIPMENT	$ 127,516					$ 127,516
PROCESS / TREATING EQUIPMENT	$ -					$ -
PRESSURE VESSELS	$ -					$ -
DIRECT FIRED HEATERS	$ -					$ -
HEAT EXCHANGERS	$ -					$ -
TANKS	$ -					$ -
PUMPS	$ -					$ -
PLC HARDWARE / SOFTWARE	$ -					$ -
MISC MATERIALS & SUPPLIES	$ -					$ -
TOTAL MATERIAL COST	**$ 127,516**					**$ 127,516**
TOTAL COMPANY COST	**$ 11,760**					**$ 11,760**
PIPELINE CONSTRUCTION CONTRACTOR	$ -					$ -
FACILITY CONSTRUCTION CONTRACTOR	$ -					$ -
TOTAL CONSTRUCTION COST	**$ -**					**$ -**
PROFESSIONAL ENGINEERING	$ 10,000					$ 10,000
INSPECTION SERVICES	$ 11,916					$ 11,916
RADIOGRAPHY SERVICES	$ -					$ -
ENVIRONMENTAL CONTRACTOR	$ -					$ -
ELECTRICAL & INSTRUMENTATION	$ 16,323					$ 16,323
RIGHT OF WAY CONTRACTOR	$ -					$ -
SURVEY CONTRACTOR	$ -					$ -
OUTSIDE LEGAL SERVICES	$ -					$ -
TOTAL OUTSIDE SERVICES	**$ 38,239**					**$ 38,239**
ROW & DAMAGES	$ -					$ -
PERMITTING	$ -					$ -
GAS LOSS	$ -					$ -
SUBTOTAL	**$ 177,515**					**$ 177,515**
CONSTRUCTION CONTINGENCY	$ 17,752					$ 17,752
AFUDC	$ 891					$ 891
SUBTOTAL	**$ 196,158**					**$ 196,158**
CAPITALIZED OVERHEAD (BURDEN)	$ -					$ -
TAX GROSS UP	$ -					$ -
GROSS ESTIMATED COST	**$ 196,158**					**$ 196,158**

ASSUMPTIONS

Include (Yes/No)	Assumptions
Yes	See Scoping Tab

Revision	Date	Notes	Approval	Name	Date
			PM	[redacted]	1/27/2021
			Director	[redacted]	
			VP	[redacted]	

AUTHORITY LEVELS:	
< $100,000	PROJECT MANAGER
$100,000 to $5,000,000	MANAGER
> $5,000,000	DIRECTOR AND VP

[redacted]

[redacted]

EXHIBIT 11

4SLB Replacement

KINDER MORGAN - MIDSTREAM

PROJECT NAME	[redacted]			
COMPANY NAME	[redacted]		COMPANY NO.	[redacted]
REQUESTED BY	[redacted]		PREPARED BY	[redacted]
ESTIMATE NO.			ORIGINAL EST. DATE	06/09/22
REVISION NO.	1.0		CONSTRUCTION CONTINGENCY	10.0%
REVISION DATE	06/09/22		OVERHEAD	16.0%
PROJ MANAGER	TBD		[redacted]	
STATE	[redacted]	COUNTY [redacted]	GROSS UP	9.0%

SCOPE

CAT replacement SCOPE:	The Caterpillar 3512 unit at this location does not have a low emissions upgrade available to allow it to meet the Good Neighbor rule limit of 1.5 g/hp-hr. This option is to replace the engine with a newer model 3512 that can achieve the lower emissions.
Tab 2 SCOPE:	
Tab 3 SCOPE:	
Tab 4 SCOPE:	
Tab 5 SCOPE:	

ASSET CAPABILITIES:

ESTIMATE SUMMARY

	CAT replacement	Tab 2	Tab 3	Tab 4	Tab 5	TOTAL
PIPE	$ -					$ -
VALVES	$ -					$ -
FITTINGS	$ -					$ -
MEASUREMENT EQUIPMENT	$ -					$ -
EFM & SCADA	$ -					$ -
COMPRESSION EQUIPMENT	$ 553,545					$ 553,545
PROCESS / TREATING EQUIPMENT	$ -					$ -
PRESSURE VESSELS	$ -					$ -
DIRECT FIRED HEATERS	$ -					$ -
HEAT EXCHANGERS	$ -					$ -
TANKS	$ -					$ -
PUMPS	$ -					$ -
PLC HARDWARE / SOFTWARE	$ -					$ -
MISC MATERIALS & SUPPLIES	$ -					$ -
TOTAL MATERIAL COST	**$ 553,545**					**$ 553,545**
TOTAL COMPANY COST	**$ 11,760**					**$ 11,760**
PIPELINE CONSTRUCTION CONTRACTOR	$ -					$ -
FACILITY CONSTRUCTION CONTRACTOR	$ -					$ -
TOTAL CONSTRUCTION COST	**$ -**					**$ -**
PROFESSIONAL ENGINEERING	$ 10,000					$ 10,000
INSPECTION SERVICES	$ 11,916					$ 11,916
RADIOGRAPHY SERVICES	$ -					$ -
ENVIRONMENTAL CONTRACTOR	$ -					$ -
ELECTRICAL & INSTRUMENTATION	$ -					$ -
RIGHT OF WAY CONTRACTOR	$ -					$ -
SURVEY CONTRACTOR	$ -					$ -
OUTSIDE LEGAL SERVICES	$ -					$ -
TOTAL OUTSIDE SERVICES	**$ 21,916**					**$ 21,916**
ROW & DAMAGES	$ -					$ -
PERMITTING	$ -					$ -
GAS LOSS	$ -					$ -
SUBTOTAL	**$ 587,221**					**$ 587,221**
CONSTRUCTION CONTINGENCY	$ 58,722					$ 58,722
AFUDC	$ 2,947					$ 2,947
SUBTOTAL	**$ 648,890**					**$ 648,890**
CAPITALIZED OVERHEAD (BURDEN)	$ -					$ -
TAX GROSS UP	$ -					$ -
GROSS ESTIMATED COST	**$ 648,890**					**$ 648,890**

ASSUMPTIONS

Include (Yes/No)	Assumptions
Yes	See Scoping Tab

Revision	Date	Notes	Approval	[redacted]	Date
			PM		1/27/2021
			Director		
			VP		

AUTHORITY LEVELS:	
< $100,000	PROJECT MANAGER
$100,000 to $5,000,000	MANAGER
> $5,000,000	DIRECTOR AND VP

[redacted]

[redacted]

586a

EXHIBIT 12

KINDER MORGAN

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	5100
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	08/24/21
REVISION NO.	BASE	CONSTRUCTION CONTINGENCY	10%
REVISION DATE		OVERHEAD	13.49%
PROJECT MANAGER	[redacted]	[redacted]	[redacted]
STATE	[redacted]	TAX GROSS UP	0.00%
COUNTY		PROJECT TYPE	KM Funded for Economics (& MC)
		IN-SERVICE	May-24
		ESTIMATE ACCURACY LEVEL	Class 3

RWIP SCOPE: Removal of existing equipment to be replaced.

CWIP SCOPE: This unit is a 4SRB unit that needs to meet 1 g/hp-hr of NOx. To achieve this a NSCR catalyst will be installed alonf with AFR controls. The unit will also be turbocharged.

ASSET CAPABILITIES:	Vol @ ### psi		Pressure
Minimum	MMCFD	Minimum	psig
Maximum	MMCFD	MAOP	psig
		Normal Operating	psig
		Delivery Pressure	psig

Metrics:
Dia (Inch) =
Length (Miles) =
Aggregate Base Lay (Per Ft) =
Total Cost (Per Ft) =
Contractor Cost (DIM) =
Directs + Contingency Cost (DIM) =

ESTIMATE SUMMARY

	Tab 12	Tab 13	RWIP	CWIP	TOTAL
MATERIAL (INCL SALES TAX)			$ -	$ 841,800	$ 841,800
COMPANY LABOR COST			$ -	$ 55,800	$ 55,800
PM, ENG, LAND, ENVIRO - EXPENSE			$ -	$ 3,200	$ 3,200
PRIMARY CONSTRUCTION CONTRACTOR			$ 162,400	$ 682,700	$ 845,100
SECONDARY CONTRACTOR			$ -	$ 2,868,600	$ 2,868,600
PROFESSIONAL ENGINEERING			$ -	$ 157,000	$ 157,000
INSPECTION SERVICES			$ 29,600	$ 221,900	$ 251,500
RADIOGRAPHY SERVICES			$ -	$ 4,700	$ 4,700
ENVIRONMENTAL CONTRACTOR			$ -	$ 21,700	$ 21,700
ELECTRICAL & INSTRUMENTATION			$ -	$ -	$ -
RIGHT OF WAY CONTRACTOR			$ -	$ -	$ -
SURVEY CONTRACTOR			$ -	$ -	$ -
OUTSIDE LEGAL SERVICES			$ -	$ -	$ -
ROW & DAMAGES			$ -	$ 10,000	$ 10,000
PERMIT FEES			$ -	$ -	$ -
GAS LOSS			$ -	$ -	$ -
SUBTOTAL			$ 192,000	$ 4,867,400	$ 5,059,400
CONSTRUCTION CONTINGENCY			$ 19,200	$ 486,740	$ 505,940
AFUDC			$ -	$ 118,818	$ 118,818
SUBTOTAL			$ 211,200	$ 5,472,958	$ 5,684,158
CAPITALIZED OVERHEAD (BURDEN)			$ -	$ -	$ -
TAX GROSS-UP			$ -	$ -	$ -
ESCALATION			$ -	$ -	$ -
RISK INSURANCE			$ -	$ -	$ -
ESTIMATED TOTAL COST			**$ 211,200**	**$ 5,472,958**	**$ 5,684,158**
Price/Ton:					
(If Applicable) Escalated Price/Ton:					
Contingency:	10%	10%	10%	10%	
In-Service Date:	May-24	May-24	May-24	May-24	

ASSUMPTIONS

Include (Yes/No)	Assumptions	
Yes	See Assumptions Tab	** Estimate shelf life is 6 months from published date.

Revision	Date	Notes	Approval	Name	Date
			Project Manager	[redacted]	
			Project Manager Director		
			Project Controls		
			Vice President		

AUTHORITY LEVELS:	
< $25,000,000	PM, PM Director, Project Controls
> $25,000,000	PM, PM Director, Project Controls, VP

Escalation Rates FV=PV(1+i)^n	
Material:	0.0%
Other:	0.0%

[redacted]

[redacted]

EXHIBIT 13

KINDER MORGAN - MIDSTREAM

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	01/18/21
REVISION NO.	1.0	CONSTRUCTION CONTINGENCY	10.0%
REVISION DATE	[redacted]	OVERHEAD	16.0%
PROJ MANAGER	TBD	AFUDC	[redacted]
STATE	[redacted] COUNTY [redacted]	GROSS UP	9.0%

SCOPE

Wauk Cat-AFR SCOPE:	Installation of catalyst, housing, exhaust modifications, Air Fuel Ratio Controller and required instruments, as well as miscellaneous ancillary equipment.
Tab 2 SCOPE:	
Tab 3 SCOPE:	
Tab 4 SCOPE:	
Tab 5 SCOPE:	

ASSET CAPABILITIES:

ESTIMATE SUMMARY

	Wauk Cat-AFR	Tab 2	Tab 3	Tab 4	Tab 5	TOTAL
PIPE	$ -					$ -
VALVES	$ -					$ -
FITTINGS	$ -					$ -
MEASUREMENT EQUIPMENT	$ -					$ -
EFM & SCADA	$ -					$ -
COMPRESSION EQUIPMENT	$ 108,658					$ 108,658
PROCESS / TREATING EQUIPMENT	$ -					$ -
PRESSURE VESSELS	$ -					$ -
DIRECT FIRED HEATERS	$ -					$ -
HEAT EXCHANGERS	$ -					$ -
TANKS	$ -					$ -
PUMPS	$ -					$ -
PLC HARDWARE / SOFTWARE	$ -					$ -
MISC MATERIALS & SUPPLIES	$ -					$ -
TOTAL MATERIAL COST	**$ 108,658**					**$ 108,658**
TOTAL COMPANY COST	**$ 20,520**					**$ 20,520**
PIPELINE CONSTRUCTION CONTRACTOR	$ -					$ -
FACILITY CONSTRUCTION CONTRACTOR	$ 57,188					$ 57,188
TOTAL CONSTRUCTION COST	**$ 57,188**					**$ 57,188**
PROFESSIONAL ENGINEERING	$ 25,000					$ 25,000
INSPECTION SERVICES	$ 23,365					$ 23,365
RADIOGRAPHY SERVICES	$ -					$ -
ENVIRONMENTAL CONTRACTOR	$ -					$ -
ELECTRICAL & INSTRUMENTATION	$ 16,004					$ 16,004
RIGHT OF WAY CONTRACTOR	$ -					$ -
SURVEY CONTRACTOR	$ -					$ -
OUTSIDE LEGAL SERVICES	$ -					$ -
TOTAL OUTSIDE SERVICES	**$ 64,369**					**$ 64,369**
ROW & DAMAGES	$ -					$ -
PERMITTING	$ -					$ -
GAS LOSS	$ -					$ -
SUBTOTAL	**$ 250,735**					**$ 250,735**
CONSTRUCTION CONTINGENCY	$ 25,074					$ 25,074
AFUDC	$ 2,509					$ 2,509
SUBTOTAL	**$ 278,318**					**$ 278,318**
CAPITALIZED OVERHEAD (BURDEN)	$ -					$ -
TAX GROSS UP	$ -					$ -
GROSS ESTIMATED COST	**$ 278,318**					**$ 278,318**

ASSUMPTIONS

Include (Yes/No)	Assumptions
Yes	See Scoping Tab

Revision	Date	Notes	Approval	Name	Date
			PM	[redacted]	1/27/2021
			Director		
			VP		

AUTHORITY LEVELS:

< $100,000	PROJECT MANAGER
$100,000 to $5,000,000	MANAGER
> $5,000,000	DIRECTOR AND VP

[redacted]

[redacted]

EXHIBIT 14

KINDER MORGAN - MIDSTREAM

PROJECT NAME	[redacted]		
COMPANY NAME	[redacted]	COMPANY NO.	[redacted]
REQUESTED BY	[redacted]	PREPARED BY	[redacted]
ESTIMATE NO.		ORIGINAL EST. DATE	01/18/21
REVISION NO.	1.0	CONSTRUCTION CONTINGENCY	10.0%
REVISION DATE	01/27/21	OVERHEAD	16.0%
PROJ MANAGER	TBD	AFUDC	[redacted]
STATE	[redacted]	GROSS UP	9.0%

SCOPE

Wauk AFR SCOPE:	Installation of Air Fuel Ratio Controller and required instruments, as well as miscellaneous ancillary equipment.
Tab 2 SCOPE:	
Tab 3 SCOPE:	
Tab 4 SCOPE:	
Tab 5 SCOPE:	

ASSET CAPABILITIES:

ESTIMATE SUMMARY

	Wauk AFR	Tab 2	Tab 3	Tab 4	Tab 5	TOTAL
PIPE	$ -					$ -
VALVES	$ -					$ -
FITTINGS	$ -					$ -
MEASUREMENT EQUIPMENT	$ -					$ -
EFM & SCADA	$ -					$ -
COMPRESSION EQUIPMENT	$ 21,086					$ 21,086
PROCESS / TREATING EQUIPMENT	$ -					$ -
PRESSURE VESSELS	$ -					$ -
DIRECT FIRED HEATERS	$ -					$ -
HEAT EXCHANGERS	$ -					$ -
TANKS	$ -					$ -
PUMPS	$ -					$ -
PLC HARDWARE / SOFTWARE	$ -					$ -
MISC MATERIALS & SUPPLIES	$ -					$ -
TOTAL MATERIAL COST	**$ 21,086**					**$ 21,086**
TOTAL COMPANY COST	**$ 11,760**					**$ 11,760**
PIPELINE CONSTRUCTION CONTRACTOR	$ -					$ -
FACILITY CONSTRUCTION CONTRACTOR	$ 57,188					$ 57,188
TOTAL CONSTRUCTION COST	**$ 57,188**					**$ 57,188**
PROFESSIONAL ENGINEERING	$ 25,000					$ 25,000
INSPECTION SERVICES	$ 11,683					$ 11,683
RADIOGRAPHY SERVICES	$ -					$ -
ENVIRONMENTAL CONTRACTOR	$ -					$ -
ELECTRICAL & INSTRUMENTATION	$ 16,004					$ 16,004
RIGHT OF WAY CONTRACTOR	$ -					$ -
SURVEY CONTRACTOR	$ -					$ -
OUTSIDE LEGAL SERVICES	$ -					$ -
TOTAL OUTSIDE SERVICES	**$ 52,687**					**$ 52,687**
ROW & DAMAGES	$ -					$ -
PERMITTING	$ -					$ -
GAS LOSS	$ -					$ -
SUBTOTAL	**$ 142,721**					**$ 142,721**
CONSTRUCTION CONTINGENCY	$ 14,272					$ 14,272
AFUDC	$ 716					$ 716
SUBTOTAL	**$ 157,709**					**$ 157,709**
CAPITALIZED OVERHEAD (BURDEN)	$ -					$ -
TAX GROSS UP	$ -					$ -
GROSS ESTIMATED COST	**$ 157,709**					**$ 157,709**

ASSUMPTIONS

Include (Yes/No)	Assumptions
Yes	See Scoping Tab

Revision	Date	Notes	Approval	Name	Date
			PM	[redacted]	[redacted]
			Director		
			VP		

AUTHORITY LEVELS:	
< $100,000	PROJECT MANAGER
$100,000 to $5,000,000	MANAGER
> $5,000,000	DIRECTOR AND VP

[redacted]

[redacted]

EXHIBIT 15

[redacted]

Date: June 6, 2022

To: [redacted]

Subject: [redacted] Kinder Morgan – [redacted] SCR System Budgetary Proposal
[redacted] Kinder Morgan – [redacted] SCR System Budgetary Proposal

[redacted],

[redacted] has been experiencing both pricing and lead time changes on all of our active projects as well as proposals issued. To date, we are seeing a nominal 25% pricing increase and 4-6 week longer manufacturing lead times based on the subject projects noted above. We anticipate that later this year or early next year that lead times and hopefully pricing will stabilize and possibly decrease.

Sincerely,

[redacted]

EXHIBIT 16

[redacted]

Kinder Morgan Operating LP "D"
370 Van Gordon Street
Lakewood, CO 80228

March 13, 2021
Project No: [redacted]
Invoice No: [redacted]
Project Manager: [redacted]

Project [redacted] Kinder Morgan - 2021 [redacted]

Email authorization by: [redacted]

[redacted] Compressor Station

TRC Environmental provided emission testing on a compressor engine at the Colorado Interstate Gas [redacted]. Three test runs were conducted on the unit to determine the emission rates of NOx, VOC and CO for the CDPHE Regulation No. 7 requests. A formal report was created that documented the result of the testing and suitable for submittal to the state and federal agencies.

Emission Testing of [redacted] Compressor -$5,000
Invoice Total Amount - $5,000

Email invoice to: [redacted]

Professional Services through: March 5, 2021
Fee

Total Fee	5,000.00			
Percent Complete	100.00	Total Earned	5,000.00	
		Previous Fee Billing	0.00	
		Current Fee Billing	5,000.00	
		Total Fee		**5,000.00**
		Total this Invoice		**$5,000.00**

[redacted]

[redacted]

Kinder Morgan Operating LP "D"
370 Van Gordon Street
Lakewood, CO 80228

March 13, 2021
Project No: [redacted]
Invoice No: [redacted]
Project Manager: [redacted]

Project [redacted] [redacted]

Email authorization by [redacted]

Compressor Station [redacted]

TRC Environmental provided emission testing on two Waukesha compressor engines at the Kinder Morgan Texas Pipeline, LLC Compressor Station [redacted]. Three test runs were conducted on the unit to determine the emission of NOx, VOC and CO over three test runs and to determine the compliance status with the federal and state limits. A formal test report was created that documented the result of the testing and suitable for submittal to the federal and state agencies.

Emission Testing of Compressor s- $11,950

Invoice Total: $11,950

Email invoice to: [redacted]

Professional Services through: March 5, 2021

Fee

Total Fee	11,950.00			
Percent Complete	100.00	Total Earned	11,950.00	
		Previous Fee Billing	0.00	
		Current Fee Billing	11,950.00	
		Total Fee		**11,950.00**
		Total this Invoice		**$11,950.00**

[redacted]

[redacted]

Kinder Morgan Operating LP "D"
370 Van Gordon Street
Lakewood, CO 80228

April 14, 2021
Project No: [redacted]
Invoice No: [redacted]
Project Manager: [redacted]

Project [redacted]

Email authorization by [redacted]

Client Name: [redacted]
Location: [redacted]
Testing Date: [redacted]

TRC Invoice Description: TRC Environmental provided emission testing on a Waukesha compressor engine at the Kinder Morgan Tejas Pipeline, LLC [redacted] Compressor Station near [redacted] Three tests runs were conducted on the unit to determine the emission of NOx, VOC and CO over three test runs and to determine the compliance status with the federal and state limits. A formal test report was created that documented the result of the testing and suitable for submittal to the federal and state agencies.

Email invoice to: [redacted]

Professional Services through: April 9, 2021

Fee

Total Fee	6,825.00			
Percent Complete	100.00	Total Earned	6,825.00	
		Previous Fee Billing	0.00	
		Current Fee Billing	6,825.00	
		Total Fee		**6,825.00**
		Total this Invoice		**$6,825.00**

[redacted]

June 21, 2022 Submitted Electronically Via www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Attn: EPA-HQ-OAR-2021-0668
1200 Pennsylvania Avenue NW
Washington, D.C. 20460

Re: Docket ID No. EPA-HQ-OAR-2021-0668 – "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," 87 Fed. Reg. 20,036 (April 6, 2022)

TC Energy respectfully submits these comments in response to the U.S. Environmental Protection Agency (EPA) proposed rule, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard,"87 Fed. Reg. 20036 (Apr. 6, 2022) (Proposed Rule). TC Energy operates over 300 reciprocating internal combustion engines (RICE), which the proposed rule would subject to unprecedented new emissions reductions requirements – requirements that would cost far more than EPA calculates, and achieve far fewer emissions reductions than EPA assumes. The Proposed Rule would significantly impact TC Energy operations in ways that EPA has not considered.

Through its pipeline subsidiaries, TC Energy operates 57,900 miles of natural gas pipelines and 653 billion cubic feet of storage capacity in North America, including numerous natural gas pipeline and storage assets. TC Energy transports approximately 25 percent of North America's natural gas to market and continues to build significant natural gas transportation infrastructure to connect new gas supplies to various consuming markets. TC Energy is proud of its history of working collaboratively with EPA to develop rational, cost-effective NO_x emissions limits through the rulemaking process, including the NO_x SIP Call Phase 2 rule.[1]

The current proposal represents a dramatic departure from this cooperative history. Without any communication with or input from the regulated Transmission and Storage (T&S) industry, EPA has proposed to require over 1400 RICE in the T&S sector to meet new emissions limits based on the installation of retrofit NO_x control – all within a three-year period. This proposal is based on a number of unfounded assumptions, including:

- EPA assumes that only 300 units industry-wide would be required to install controls, when the actual figure is over 1,400 based on a review by the Interstate Natural Gas Association of America (INGAA). Indeed, TCE alone operates over 260 RICE that would be subject to the proposed rule.

[1] 69 FR 21604, "Interstate Ozone Transport: Response to Court Decisions on the NOX SIP Call, NOX SIP Call Technical Amendments, and Section 126 Rules; Final Rule," April 21, 2004.

- The costs to retrofit this many engines will be significantly higher than EPA assumes. TC Energy's internal study indicates that retrofitting over 260 units would cost up to $900,000,000.

- EPA's benefits analysis in the RIA assumes that regulated engines would reduce emissions by an average of 75 tons per year NO_x. Yet the 2017 NEI data in the spreadsheet EPA uploaded to the docket illustrates that only a quarter of regulated units even *emit* 75 tpy NO_x – meaning that the overall emissions reductions the rule would achieve will be significantly lower than EPA assumes.

- EPA assumes that the T&S sector can retrofit all affected engines within three years. Information from past EPA rulemakings demonstrates that only about 75 engines a year can be retrofitted on a sustained basis, given resource constraints and the time involved in obtaining and installing the required equipment. Even this projection is likely optimistic given the recent supply chain disruptions that have resulted from the COVID-19 pandemic. EPA's three-year schedule would be infeasible even with only 300 affected units nationwide – much less the more than 1400 that actually exist.

- EPA has not considered the impact of the proposal on the T&S industry's ability to comply with its FERC obligations. Because natural gas is a critical resource, FERC requires interstate pipelines to be able to provide maximum capacity at all times. To meet the proposed rule's three-year deadline, however, T&S companies will have no choice but to take multiple units out of service at the same time, leaving pipelines across the nation without the backup capacity needed to meet FERC's requirements – particularly if an unforeseen malfunction takes one of the remaining engines out of service.

The consequences of the proposed rule will affect far more than the T&S sector. Citizens and businesses rely on companies like TC Energy to provide the natural gas they need to heat their homes, cook their food, and run their businesses. That is *why* FERC regulates capacity: to ensure that citizens are not left without heat in January, and to minimize their vulnerability to the price spikes that accompany severe shortages of natural gas. Put simply, the country cannot afford disruption on this scale – particularly at a time when energy prices are rising dramatically, and when energy security is more important than ever.

TC Energy very strongly recommends that EPA reconsider both the universe of engines that require controls and the timeframe in which those controls must be installed. We offer our assistance in helping EPA develop more feasible alternatives that protect both the public health and its energy supply.

Sincerely,

DocuSigned by:

Matt Parks

CB3D093AC93C412...

Matt Parks

Title: VP Technical Operational Svc USPL

TC Energy Comments on the Proposed Rule, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard,"

87 Fed. Reg. 20,036 (April 6, 2022)

Submitted: June 21, 2022

www.tcenergy.com

TC Energy respectfully submits these comments in response to the Environmental Protection Agency's (EPA) proposed rule, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," (Proposed Rule).

DETAILED COMMENTS

1. EPA has significantly under-estimated the number of natural gas transmission and storage (T&S) reciprocating internal combustion units subject to the Proposed Rule, along with the cost of achieving the proposed emission reductions.

The Proposed Rule would require NO_x reductions from RICE used for pipeline transportation of natural gas. In the preamble and supporting documentation, EPA estimates that there are 307 affected units in this sector.[2] This estimate significantly underestimates the number of affected units. TC Energy operates 360 RICE in sixteen affected states that exceed the 1,000 horsepower (hp) applicability threshold. Over 80% of these units are not currently equipped with NO_x controls and so would require significant retrofits or replacement to achieve the proposed emission limits; another 10% include some level of NO_x control but would require additional controls to meet the proposed emission limits. Excluding units currently being retired, TC Energy alone operates 263 units that would require retrofit NOx control – almost as many as EPA assumes exist across the entire T&S sector. In contrast, EPA's list of 307 units includes only 56 TC Energy units, two of which are turbines, which are not subject to the Proposed Rule.

The Interstate Natural Gas Association of America (INGAA)[3] has also conducted a review of affected units across all its members, which identified nearly 1,380 units that would require NO_x controls – 350% higher than EPA's estimates.[4] This figure does not even include units owned by non-INGAA members or those in the natural gas gathering and boosting sector that fall within the applicability triggers in the proposed rule. **All told, EPA has undercounted the number of affected units in the T&S sector by almost a factor of five.** As discussed below, the significant underestimation of affected unit counts results in an equally significant underestimate of the costs of compliance, along with implications for the compliance schedule that could even impact the reliability of the natural gas transmission pipeline network.

For TC Energy, disparities in unit counts occur across our system and are not limited to a particular state or region. Further discussion follows in these comments, and TC Energy welcomes additional discussion with EPA to ensure a sound technical basis for the applicability threshold in § 52.41(b) and associated definitions in § 52.41(a).

The underestimation of unit counts is primarily due to EPA's failure to account for typical operational use (*i.e.*, "utilization") in T&S as compared to other sectors. For the Proposed Rule, EPA analysis identified non-EGU units with actual emissions above 100 tons per year (tpy), which EPA then equated to a 1,000 hp RICE. However, the vast majority of 1,000 hp RICE do *not* emit anywhere close to 100 tpy.

Interstate natural gas pipeline systems operate in a unique regulatory environment, because a pipeline may be constructed only if the Federal Energy Regulatory Commission (FERC) certifies that the pipeline is "necessary." As a result, pipeline compressor stations must, by law, be designed with enough

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[2] *See, e.g.*, Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Oxone Transport for the 2015 Ozone National Ambient Air Quality Standard, EPA-452/D-22-001 (Feb. 2022) (RIA) at 4-45, Table 4-18,

[3] TC Energy is a member of INGAA.

[4] INGAA members represent approximately 80% of domestic interstate natural gas transmission pipeline miles.

compression to provide the full capacity identified in the FERC certificate on peak demand days (*i.e.*, the coldest, multi-day winter event for heating). The vast majority of operating days, however, do not even approach this level of demand, because natural gas demand fluctuates significantly over the course of the year due to variations in heating and cooling demands. As a result, while most compressor stations are constructed with multiple units to meet the highest-demand days, most units operate minimally over the course of the year. On average, system utilization in the United States is on the order of 40% for compressor stations and lower for underground storage facilities. A TC Energy analysis indicates even lower utilization across the TC Energy system, averaging less than 30% for the entire RICE fleet.

The data that EPA relies on – the 2017 NEI engine data posted in the Docket[5] – illustrates this disparity. When that spreadsheet is sorted by highest-to-lowest NOx emissions, lines 1-811 of the spreadsheet exceed 100 tpy.[6] On the other hand, when the spreadsheet is sorted by largest-to-smallest engine size, lines 1-3,986 involve engines over 1000 hp. In other words, while almost all of the 100-tpy units exceed 1,000 hp, only one in five of the 1,000-hp units exceeds 100 tpy. Indeed, line 788 on the largest-to-smallest-engine sort is a 4,000 hp unit.

EPA's significant undercounting of the number of units that will be regulated under the proposed rule skews its cost-benefit analysis by undercounting the costs and overcounting the benefits. First, the cost of retrofitting almost 1400 units is significantly higher than the costs of retrofitting the 307 that EPA assumed would be regulated. In addition, a 1,000 hp unit is on the smaller end of the size range for typical T&S compressor drivers, and these units often entail higher retrofit costs than larger units, because they typically require more significant upgrades such as installing turbochargers (which may not be required for larger RICE). TC Energy's own internal analysis has concluded that it could cost up to $900,000,000 to retrofit the over 260 units in its own system.

Second, the low emissions from the vast majority of the 1,000 hp units means that the proposed rule will not achieve the emissions reductions that EPA assumes. EPA's Regulatory Impact Analysis assumes that 296 engines in the Eastern region will achieve total NO_x reductions of 22,390 tpy, for an average of 75 tpy per unit. RIA at 4-45. The NEI data that EPA relies on, however, demonstrates that only about 25% of units over 1,000 hp even *emit* as much as 75 tpy.[7] These smaller engines are more likely to be operated sporadically (*e.g.*, when incremental HP is dispatched to address higher pipeline demand) and typically operate less than 20% of the year, resulting in actual emissions that are significantly below the engines' design capacity.

EPA should further review the applicability trigger and cost-benefit analysis to ensure that it has (a) identified *all* units that will be regulated under the proposal, and (b) accurately accounted for the true costs of retrofitting those units and the actual emissions reductions that those retrofits can achieve. Unless and until EPA does so, it would be arbitrary and capricious to move forward with efforts to regulate those units.

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[5] The data is presented in an Excel spreadsheet entitled EPA-HQ-OAR-2021-0668-0058_content.

[6] Note that many rows are hidden in this spreadsheet, presumably because they do not involve engines in the states involved in the current FIP proposal. Referring to "rows 1-788" does not mean that 788 engines exceeded 100 tpy; the numbers are used only to illustrate the disparity between 100 tpy sources and 1,000 hp engines.

[7] As noted above, when sorted by size, lines 1-3986 of the spreadsheet include engines of at least 1000 hp. When sorted by emissions, however, only lines 1-1034 include engines that emit at least 75 tons. The remaining 2,950 lines represent engines that are over 1000 hp that emit less than 75 tpy.

2. The Proposed Rule should be revised to add compliance flexibility for T&S units, including emissions averaging and case-by-case review.

The Proposed Rule should be revised to add compliance flexibility, including emissions averaging similar to the model rule developed by EPA for the NO_x SIP Call Phase 2 rule, and case-by-case review to accommodate scheduling, especially for retirement or replacement of affected RICE. Comment 1 discusses the significant under-estimation of the number of affected RICE, which are primarily lean burn engines. Comment 3 discusses the infeasibility of the proposed compliance schedule, which is exacerbated by a much larger affected T&S fleet than EPA estimates. These issues are obviously inter-related, and compliance flexibility discussed in this comment is a partial remedy. Ultimately, reconciliation of affected unit counts and a revised applicability threshold, compliance flexibility, and a multi-year compliance schedule are all needed to address significant issues with the Proposed Rule.

TC Energy recommends that EPA revise the Proposed Rule to include proven compliance options adopted in response to the 2004 NO_x SIP Call Phase 2 rule and in related state NO_x RACT. This includes emissions averaging and case-by-case review. The latter is especially important when considering the schedule for mitigation options that may include replacement or retirement of older, higher emitting RICE.

Emissions Averaging

TC Energy recommends that EPA adopt emissions averaging, as it did in the NO_x SIP Call Phase 2 rule, as it has encouraged states to do, and as many states have successfully implemented. EPA, INGAA, and other stakeholders including TC Energy extensively discussed similar issues in response to the NO_x SIP Call; those discussions resulted in the development of the 2004 NO_x SIP Call Phase 2 rule, where EPA evaluated and supported reliance on emissions averaging for RICE in the natural gas pipeline sector. Indeed, EPA's guidelines to states on developing an appropriate SIP in response to the SIP Call advocated for providing companies the "flexibility" to use a number of control options, as long as the *collective* result achieved the required NOx reductions:

> During the SIP development process the States may establish a *NOx tons/season emissions decrease target for individual companies and then provide the companies with the opportunity to develop a plan that would achieve the needed emissions reductions*. The companies may select from a variety of control measures to apply at their various emission units in the State or portion of the State affected under the NOx SIP call. These control measures would be adopted as part of the SIP and must yield enforceable and demonstrable reductions equal to the NOx tons/season reductions required by the State. *What is important from EPA's perspective is that the State, through a SIP revision, demonstrate that all the control measures contained in the SIP are collectively adequate to provide for compliance with the State's NOx budget during the 2007 ozone season*. [8]

The 2004 Phase 2 NOx SIP Call adopted this approach, using almost exactly the same language.[9]

The 2004 rule also included a model rule that states could adopt as part of their SIPs. The model rule was built on the principle of emissions averaging, centering on a "Facility Seasonal NOx 2007 Tonnage

[8] Memorandum from Lydia N. Wegman, "State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NOx) – Stationary Reciprocating Internal Combustion Engines" (Aug. 22, 2002) ("Wegman Memo") (emphases added).
[9] 69. Fed. Reg. 21,604, 21,621 (Apr. 21, 2004).

Reduction," which EPA defined as "the total of the Engine Seasonal NOx 2007 Tonnage Reductions attributable to all of an owner/operator's Large NOx SIP Call Engines," *i.e.*, the engines subject to the rule's requirements.[10] Simply put, the model rule allowed each company to develop its own compliance plan – identifying which facilities and engines would be included in the plan, which engines would receive additional emissions control, and what types of controls to use – as long as the plan achieved overall emissions reductions "equal to or higher than the Facility Seasonal NOx 2007 Tonnage Reduction."[11] Indeed, the model rule even allowed companies to obtain credit for emission reductions from engines not subject to the SIP Call:

> Credit may also be included for decreases in NOx emissions from other engines in the State due to NOx control equipment not reflected in the 2007 Ozone Season Base NOx Emissions in the NOx SIP Call Engine Inventory.[12]

As EPA had recommended, many states built their revised SIPs around the emissions averaging approach that EPA advocated for in the model rule. Some of these states include:

Pennsylvania has adopted emission averaging provisions to address NO_x and volatile organic compounds for purposes of RACT, and EPA has approved those provisions.[13] Alternative NO_x RACT emission limits include facility-wide or system-wide NOx emissions averaging plans. To assess the effectiveness of averaging, Pennsylvania conducted an evaluation of aggregate NO_x emissions emitted by the sources included in the facility-wide or system-wide NO_x emissions averaging plan. The state concluded, and EPA agreed, that those emission reductions under the averaging plans would be equivalent to emissions if the individual sources were operating in accordance with the applicable presumptive limit. Accordingly, EPA approved the approach, determining that the averaging plan was consistent with all applicable laws and regulations, and approved the plan.

New York has also adopted emission averaging rules.[14] New York's rules require emission averaging plans to employ a weighted average permissible emission rate and include provisions for adjusting the weighted average to address forced outages. The state's rules also prohibit averaging of emissions from sources within the severe ozone nonattainment area with those outside the severe ozone nonattainment area.

Ohio has adopted similar regulations authorizing owners and operators of affected RICE to comply with NO_x emission standards through EPA-approved emission averaging plans.[15] Ohio's rules require that emission reductions counted under such a plan be "real, quantifiable and enforceable and … in excess of any state or federal requirements." The rules further provide that those emission reductions must be equal to or greater than the actual emission reductions that would be required under Ohio's rules if an emission averaging program were not employed. Further, Ohio allows an owner or operator to take credit for emission reductions resulting from a unit shutdown only if the owner or operator can demonstrate that "the shutdown does not correspond to load-shifting or other activity which results in or could result in an

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[10] Model Rule § 1(c).
[11] *Id*. § 3(a)(2).
[12] *Id*. § 3(a)(5).
[13] *See* 87 Fed. Reg. 3929 (Jan. 26, 2022).
[14] 6 NYCRR 227-2.5(b).
[15] Ohio Admin. Code 3745-110-03(I).

equivalent or greater emission increase and that the reduction accounts for any increase in NOx emissions from other sources as a result of the shutdown."[16]

Texas has allowed emission averaging to demonstrate compliance with its emission reduction requirements for existing RICE located in West and East Texas. Those rules generally require each affected engine in East Texas to achieve at least a 50% reduction of the hourly emissions rate of NO_x and affected engines in West Texas to achieve up to a 20% reduction of the hourly emissions rate of NO_x.[17] The rules further provide, however, that "the owner or operator of more than one grandfathered reciprocating internal combustion engine may average the reductions achieved among more than one reciprocating internal combustion engine connected to or part of a gathering or transmission pipeline in order to demonstrate" the required reductions.[18] The Texas rules even allow averaging across engines located in both East and West Texas so long as the owner or operator demonstrates that "the sum of the reductions achieved from all of the engines located in the East Texas region as defined in §101.330 of this title will achieve the reductions" required of such units.[19]

Illinois allows owners and operators of affected RICE units to comply with NO_x emission limits through an emissions averaging plan.[20] Illinois follows the EPA model rule, and the IL EPA rule provides equations by which owners and operators must demonstrate that total mass of actual NOx emissions from the units listed in the emissions averaging plan are equal to or less than the total mass of allowable NOx emissions for those units for both the ozone season and calendar year.

In addition to these and other states, the Ozone Transport Commission ("OTC") developed NO_x RACT technical guidelines for RICE used in natural gas transmission[21] and included emissions averaging in those guidelines. The OTC guidelines provide emission rate limits that would apply to various types and sizes of RICE. They also include provisions that would authorize emission averaging for multiple natural gas fueled units that are under the control of a common owner or operator at a single facility to achieve the same level of NOx reductions that would be achieved if all of the units at the location met the applicable NOx emissions limitations of the guidelines.[22]

Clearly, emissions averaging, as developed and outlined by EPA in its 2002 Wegman memo and model rule, is a valuable tool for achieving cost-effective NO_x reductions under region-wide programs. The regulatory structure is already in place throughout the states affected by the Proposed Rule to expand that approach to address the additional units covered by the Proposed Rule.

As discussed in Comment 3, the Proposed Rule would require non-EGU sources to comply beginning in 2026, but that deadline is not feasible to control all of the units subject to the Proposed Rule, and the challenge is exacerbated by EPA's significant under-estimation of affected units. A final rule that integrates emissions averaging, in conjunction with a phased schedule discussed in Comment 3, can provide a pathway to efficiently achieving NO_x reductions on a timely basis to meet regulatory objectives.

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[16] *Id*. at 3745-110-03(I)(1)(e).
[17] 30 TAC § 116.779 (b)(1), (2).
[18] *Id*. § 116.779 (b)(3)
[19] *Id*.
[20] Ill. Admin. Code tit. 35, § 217.390.
[21] OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NOx) Emissions from Natural Gas Pipeline Compressor Fuel- Fired Prime Movers (May 14, 20-19), available at Microsoft Word - OTC_RegAndTechGuideline_NGPipelineCompressorPrimeMovers_Final_05142019.docx (otcair.org).
[22] *Id*. at 5.1.2.

Case-by-case Review

To address potential compliance schedule complications, the Proposed Rule requests comment on a case-by-case extension process for non-EGU sources. EPA asks for specific criteria to judge such requests and the process for reviewing and acting on such requests. A flexible and timely approach for addressing case-by-case compliance deadline extensions is an important measure that could be of significant use to both affected operators and permitting authorities. TC Energy recommends a process similar to the approach used to determine "alternatives" for reasonably available control technology (RACT) for individual sources. EPA could implement such a process via the FIP, and could also clearly indicate in the final rule that states could submit simple SIPs (*e.g.*, revisions to an existing state NO_x RACT rule) to assume control of this process.

As an example, with hundreds of affected units (see Comment 1), TC Energy will need to consider many factors in implementing its response. In addition to NO_x retrofit for many RICE, decommissioning or replacement of some units will occur. Significant planning will be necessary to design and execute the plan, including addressing requisite permitting requirements through the Federal Energy Regulatory Commission (FERC), as discussed in Comment 3. Schedule allowances to accommodate decommissioning or replacement could be executed within a multi-year phased program (see Comment 3), but a case-by-case review process will be needed regardless of the phase in period to ensure that unavoidable permitting and scheduling complications can be addressed.

For this process, TC Energy recommends that once a complete application for a case-by-case determination is submitted, the relevant compliance date or dates are adjusted to account for the time taken by EPA (or state decisionmaker) to make a final determination regarding the extension. This is necessary to ensure stakeholders are not disadvantaged by a lengthy agency review process.

Even if case-by-case review is adopted, TC Energy strongly believes that T&S RICE require a more comprehensive and complete solution to address inter-related issues including the under-estimate of affected RICE units, and the need for a multi-year phased schedule to accommodate resource constraints and permitting timelines. As was done with the 2004 NO_x SIP Call Phase 2 rule, TC Energy offers its assistance in helping EPA understand related technical issues when devising workable solutions in the final rule.

3. The implementation schedule is infeasible and a phased schedule should be adopted for affected T&S units.

In past rulemakings where EPA has considered addressing interstate transport of ozone by including emission reduction requirements for RICE in the natural gas pipeline industry, EPA has acknowledged that significant time and resources are needed for installing retrofit control technologies, obtaining needed permits, and managing the timing for staggering retrofits. EPA has also acknowledged that limitations in technical expertise and resources, *e.g.*, aftermarket service providers that address LEC retrofit NO_x control, affect emissions control upgrade schedules.

The situation is more concerning now than during these past rulemakings, because COVID-19-related supply chain disruptions have significantly limited the availability of both necessary equipment and the qualified personnel necessary to design, transport, and install it. Retrofitting even 300 units, as EPA assumed, within the three-year timeframe provided would be extremely difficult; retrofitting the almost 1400 units that are actually regulated will be impossible for all intents and purposes.

The Proposed Rule, however, does not build on any of EPA's past experience. nor does it consider the significant new challenges posed by COVID-19. Rather, the rule sets forth a fixed 2026 compliance deadline for all units. This cannot reasonably be done. TC Energy recommends a phased approach, and offers our assistance in working with EPA to resolve scheduling concerns and defining a successful approach for phasing in emission reductions from T&S RICE over several years.

The following discussion provides background on LEC retrofit resource constraints, related permitting constraints, and significant concerns about the implications of an aggressive compliance schedule on natural gas transmission system reliability.

Background on Resource Constraints and Schedule Implications

In previous rules where NO_x control of existing RICE in T&S was considered, EPA has acknowledged significant time and resources are needed for completing retrofit emissions control. The Proposed Rule compliance timeframe is not consistent with EPAs past decisions, and the market constraints that supported previous EPA decisions have not changed. In fact, supply chain challenges that have arisen in conjunction with the pandemic have only added to the challenges.

A 2014 report prepared for the INGAA Foundation, Inc. and submitted to EPA as part of rulemaking docket for its 2014 CSAPR "Close-out" rule evaluated "the resources required of the operating companies, emission reduction suppliers, engineering service providers, and contractors to implement NOx control regulations for low speed reciprocating engines used in the interstate natural gas transportation industry" and concluded that "the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules." The report is extremely relevant to the current rulemaking and has been cited by EPA. The report evaluates the same emission control technologies considered in the Proposed Rule, including Low Emission Combustion (LEC) and nonselective catalytic reduction (NSCR). The report also contains a review of the various types and numbers of RICE inventoried at the time, and is cited by EPA in the Technical Support Document[23] for a 2015 rulemaking.

The report's evaluation of potential regulatory drivers includes a new regional rule to address interstate transport comparable to but more stringent than the 2004 Phase 2 NO_x SIP Call – precisely what the Proposed Rule is – and it specifically considers potential impacts (including "a broad regional NOx control rule") of a 2015 ozone NAAQS set in a range from 60 to 70 parts per billion ("ppb"), accurately reflecting the current regulatory landscape. It also evaluated available resources and the cost and schedule to install controls based on NO_x endpoints of 3 g/bhp-hr or 1 g/hp-hr, consistent with the limits EPA has now proposed.

After reviewing this fundamental information, the report provides an assessment of resource constraints associated with NOx control retrofits. In doing so, it provides relevant examples, such as the conversion of over 200 natural gas transmission RICE to add LEC starting in 1999 as part of the NO_x SIP Call (and related Phase 2 rule). The report finds "[f]rom interviews with the operators and the emission reduction equipment suppliers, the conversion process took six years in total to fully implement." The report further concludes that, generally, "[b]ased on interviews with pipeline operations and emission reduction

[23] Docket ID No. EPA-HQ-OAR-2015-0500, "Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance," November 2015.

equipment suppliers having experience with previous conversion projects, NOx control for each engine requires between 1 and 2 ½ years to complete (from inception to completion of commissioning)" with older engines and retrofits requiring more infrastructure modifications taking additional time. Most importantly for purposes of a broadly applicable rule like the Proposed Rule, "[t]aking into account both the lead time and conversion time and based on currently available resources (i.e., trained personnel), *the average number of units that can be modified to lean combustion on a sustained basis is approximately 75 engines per year*." (emphasis added). The report's conclusion in this regard is based on what it calls current resource availability, but it acknowledges that "a dramatic increase in market demand would likely result in hiring and training of additional resources." Nevertheless, "the special skills associated with this niche market would require time to build that resource."

To retrofit RICE to meet a 3 g/hp-hr standard, the report estimates that "[b]ased on current technical resources, the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules[, and] that it would take decades to address NOx controls for a large number of engines, even if the annual rate of retrofit conversions is doubled." Retrofitting a smaller number of engines to achieve a 1g/hp-hr standard, the report concludes, would have a minimal impact on schedule, but would have "a significant cost impact, with engine-specific costs on average about 65% higher to achieve 1 g/hp-hr."

The market for expert services needed to conduct the retrofits that would be required by the Proposed Rule has not improved since the preparation of the Control Availability Report. EPA's own estimate that all regulated RICE can install controls by the 2026 ozone season is undermined by the EPA's substantial underestimation of affected units, as described in Comment 1. For the existing equipment in natural gas transmission, there is a limit of qualified service providers that support control implementation. Factors to be considered include service provider and equipment availability (which is limited), access to multiple vendors that serve the supply chain, budget cycles and lead time for procuring equipment, consideration of control installation downtime requirements of about one month for each unit serviced, operating constraints that limit out-of-service equipment, and timing for permitting. Further, current supply chain issues affecting the economy as a whole will undoubtedly result in further delays in performing necessary retrofits. Seasonal gas demand can also impact schedule, because operators are legally obligated by FERC to ensure capacity is available during higher-demand periods, which limits the ability to remove units from service to install retrofit controls. As discussed below, the reliability of the domestic natural gas transmission network could be impacted if the compliance schedule forces too many units to be out of service at once, with greater risk of reliability impacts during higher demand periods.

EPA has acknowledged the relevance of this issue in past rulemakings. Most recently, in conjunction with an assessment of non-EGU NO_x control in the November 2015 TSD noted above, EPA notes the following regarding NOx emissions control for natural gas transmission RICE,

> "While some of the recommended control technologies may involve installation timelines that are relatively short on a per-engine basis, there is substantial uncertainty in large-scale installation over numerous sources. *References indicate that implementation of NOx controls of any type on a large number of RICE will require significant lead time to train and develop resources to implement emission reduction projects; market demand could significantly exceed the available resource base of skilled professionals. Additionally, in order not to disrupt pipeline capacity, engine outages must be staggered and scheduled during periods of low system demands for those engines involved in natural gas pipelines (as is the case with 3 of the 4 RICE source groups with significant cost-effective reductions).* In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make

installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as RICE." (emphasis added).

Permitting Constraints

Permitting constraints can significantly affect the timeframe needed for completing retrofits required by the Proposed Rule or otherwise mitigating emissions (*e.g.*, via decommissioning / replacement). Due to workload at permitting agencies, the permitting process typically takes six months to fifteen months complete, and in some cases the process can take longer. The Proposed Rule would affect hundreds of permitted T&S facilities across the affected states, and this is likely to cause additional challenges (and resulting delays) in at least some locations.

In addition, the Proposed Rule does not consider that interstate pipeline operators who choose to replace RICE with new units must seek permitting approval from various federal agencies, including FERC in many cases. The FERC timeline for review will likely take a *minimum* of 1½ years. Operators must also obtain various environmental permits from permitting agencies, as relevant, such as US Army Corps of Engineers, EPA, Department of Interior's Fish and Wildlife Service, and submit for PHMSA safety review. In addition, the need to retrofit or replace almost 1400 units nationwide within the same three-year period will necessarily trigger a substantial increase in the number of certificate or permit applications submitted for review within a very short window of time, which will challenge agency resources at both the federal and state levels and further extend processing times.

System Reliability

Requiring such extensive changes to the natural gas transmission system within such a short timeframe will very likely lead to reliability issues across the system. Installation of controls will require taking affected units offline for extended periods of time; the number of units affected means that these efforts will need to extend to multiple units within a facility and/or at nearby compressor stations on the same pipeline. These system-wide unit outages, in turn, leave the pipeline vulnerable to unexpected engine malfunctions or sudden spikes in demand; without the additional capacity provided by the engines that have been taken out of service for retrofit/replacement, the pipeline may not be able to keep up with demand. Each of these pipelines, in turn, operates as part of an interconnected system – and each of those other pipelines connecting to that system will be undergoing the same capacity constraints due to the need to retrofit their own engines.

The failure of the pipeline system to keep up with demand can have serious consequences for local businesses and residents who count on the natural gas the pipelines supply to heat their homes and run their businesses. For example, New England "has no indigenous fossil fuels and therefore, fuels must be delivered by pipeline, ship, truck, or barge from distant places." "[A] failure at a single point on the pipeline system . . . in New England will likely create significant impacts."[24] The pipelines delivering natural gas into New England run through states such as New York, Pennsylvania, and Virginia – states covered by the Proposed Rule. Contemporaneous retrofit that takes RICE offline in those states could reduce capacity delivered into the northeast and New England and cause significant disruptions.

Neither the Proposed Rule nor any of the technical support documents currently in the docket provide any substantive analysis of reliability issues for the interstate natural gas pipeline industry. EPA cannot reasonably evaluate the appropriateness and feasibility of the Proposed Rule without assessing potential

[24] ISO-NE, Natural Gas Infrastructure Constraints, available at https://tinyurl.com/2p9ewwjc.

impacts on natural gas system reliability, supplies, and price. The Proposed Rule, accordingly, lacks a reasoned basis based on the current record. To address this shortcoming, EPA must evaluate reliability and tailor its rule to prevent serious and predictable reliability problems.

4. **Compliance assurance monitoring should rely on parameter monitoring systems implemented through state permits. CEMS should not be required.**

The Proposed Rule requests comment on RICE continuous monitoring for compliance assurance. TC Energy recommends the following:

- Continuous parameter monitoring is appropriate for RICE;
- EPA should defer to state permitting processes for continuous parameter monitoring implementation.
- CEMS are not warranted.

Parameter Monitoring for Lean Burn RICE

Low emission combustion (LEC) is the preferred NO_x control for all lean burn engines. Once installed, LEC technology is inherent to engine operation and the combustion controls cannot be "turned off" or bypassed. Compliant emissions are ensured by proper operation of the combustion process, and basic operating parameters can be monitored to ensure combustion health. The Proposed Rule requires a site-specific monitoring plan for LEC engine CPMS, and TC Energy recommends that EPA defer authority for review and implementation of LEC parameters monitoring to states. A brief overview of example parameters to monitor is discussed based on permit conditions for LEC monitoring at existing major source facilities (*e.g.*, to address compliance with state RACT requirements).

The majority of affected T&S RICE are two-stroke or four-stroke lean burn (2SLB or 4SLB) units, and combustion-based emission controls will include adding additional air (to lower temperatures and decrease NO_x), higher energy ignition to ensure the lean mixture is ignited, and/or higher pressure fuel injection to improve the uniformity of the in-cylinder mixture and enhance combustion stability. Combustion performance is ensured by monitoring parameters that indicate operation within expected norms, including fuel use, air manifold pressure and air manifold temperature. The parameters, measurement specifications, and accepted operating range would be provided in the monitoring plan, and similar plans will be utilized for all lean burn engines in a company fleet. In many cases, states have already integrated analogous parameter monitoring requirements into facility permits. EPA should defer lean burn engine parameter monitoring oversight to states.

Parameter Monitoring for Rich Burn Engines

For 4-stroke rich burn (4SRB) engine parameter monitoring, the Proposed Rule includes continuous monitoring of catalyst inlet temperature and monthly monitoring of catalysis pressure drop (ΔP). Section 52.41(d)(3)(ii) of the Proposed Rule requires ΔP monitoring monthly, with maintenance required "if the pressure drop is greater than 2 inches outside the baseline value established after each semiannual portable analyzer monitoring."

The criteria are similar to RICE NESHAP monitoring requirements for 4SRB engines with NSCR, but fail to acknowledge an important operational constraint: ΔP can vary from month to month due to the operating load of the engine because exhaust flowrate changes with load. Thus, rather than requiring the operator to "conduct maintenance" and to compare to a "baseline value established after each semiannual portable analyzer monitoring," the operator should assess the test conditions and compare the ΔP to a value obtained from any previous emissions test conducted at a similar load, and then assess whether action is warranted, rather than *requiring* “maintenance.” The operator can maintain records to document any instance where monthly ΔP monitoring warrants additional review, follow-up, and/or maintenance.

Fluctuations in ΔP are discussed and explained in great detail in INGAA comments on the 2002 RICE NESHAP proposal, including documentation of how ΔP can vary with engine load. The RICE NESHAP approach to conduct ΔP at “full load” and compare to the value from a “full load” performance test is not recommended, because full load may not be achievable month-to-month. Similarly, comparing to the most recent performance test result may not be appropriate because that test may not be at a similar engine load. Thus, TC Energy recommends that monthly ΔP monitoring assess the measured value relative to the result from a previous performance test at a similar load. The operator can maintain records of the measurement, with review or actions taken (as needed) when the value varies by more than 2 inches (of water column) from the value measured in a previous test at similar load.

CEMS are Not Warranted for Natural Gas Transmission Reciprocating Engines

The Proposed Rule solicits comment on using CEMS for continuous compliance monitoring. EPA has considered CEMS for natural gas transmission compressor drivers (RICE and turbines) in past rulemakings, and consistently concluded that CEMS are not warranted due to costs and the availability of other established methods for compliance assurance. This basis still stands, and CEMS are not warranted.

EPA contemplated NO_x CEMS during combustion turbine NSPS review in 2005. The preamble to proposed Subpart KKKK indicates that NO_x CEMS were considered as a monitoring requirement, but EPA concluded that CEMS costs are too high relative to a reliable alternative : annual stack testing and/or parameter monitoring. INGAA supported the EPA conclusion regarding the excessive costs of CEMS (without commensurate benefit), and also supported the conclusion that a periodic source test provides a reliable basis for demonstrating compliance with the NSPS standard. In Subpart KKKK, parameter monitoring is provided *as an alternative* to testing. This rulemaking would include both parameter monitoring and periodic tests, thus providing an extra measure of assurance.

Analysis on CEMS costs is presented in a docket memorandum from the Subpart KKKK rule (Docket Document No. OAR-2004-0490-0115). Conclusions regarding CEMS are further supported by:

- CEMS cost analysis for other RICE rules that indicate costs similar to or higher than the cost projection for Subpart KKKK.
- Recent precedent from NSPS and NESHAP rulemakings regarding monitoring requirements and the exclusion of CEM requirements.

In addition to the cost analysis in the Subpart KKKK docket, other EPA rulemakings considered CEMS costs, including consideration of CO CEMS for NESHAPs. Note that CO CEMS costs are comparable to NO_x CEMS costs, with NO_x CEMS likely to be marginally more costly due to higher instrumentation and operating costs. Additional examples of regulations that considered and rejected CEMS include the Turbine NESHAP, Engine Test Cell NESHAP, Reciprocating Internal Combustion Engine NESHAP, Petroleum Refinery NESHAP, Mineral Wool NESHAP, and Hospital / Medical / Infectious Waste Incinerator NESHAP. For these standards, analysis indicated CEMS costs similar to or higher than the estimate for Subpart KKKK. In each case, costs were considered excessive and CEMS were not required.

These decisions are relevant because they provide an indication of consistency in EPA’s justification of monitoring requirements, and also because of the environmental burdens associated with the sources and regulations that did not require CEMS under Part 63. For example, the environmental implications of the Waste Incineration MACT invoke a higher level of concern and are associated with a higher probability of emissions performance variability than NO_x emissions from RICE, where periodic performance tests and parameter monitoring assure compliance.

In addition, the efficacy of reciprocating engine LEC supports an approach based on parameter monitoring and periodic testing. As opposed to add-on emission control technologies where performance can be dramatically affected by short term deviations in a key process parameter (e.g., ammonia feed rate for SCR), LEC is a pollution prevention approach, with the NO_x control inherent to the design and operation of the engine. The control technology cannot be "turned on or off" by the operator, and emissions performance is inherent to the operation and functionality of the unit. Periodic tests provide additional assurance – *e.g.*, whether minor changes or upward trending of NO_x emissions may occur over longer time periods due to equipment wear. Because of the performance of LEC combustion technology and the viability of periodic source tests and parameter monitoring, implementation of CEMS cannot realize an incremental benefit in ensuring performance commensurate with the CEMS costs.

For engines, the proposed RICE NESHAP (Part 63, Subpart ZZZZ) considered CEMS for carbon monoxide (CO) for lean-burn engines greater than 5,000 horsepower to demonstrate compliance with the CO percent reduction standards. For lean burn engines less than 5,000 horsepower, EPA proposed periodic stack testing and continuous monitoring of operating parameters. For that standard, EPA ultimately concluded that CEMS were not warranted for the larger units and parameter monitoring and periodic tests assured compliance.

EPA estimated CO CEMS costs for both the RICE NESHAP and the Engine Test Cell NESHAP, with estimated costs slightly higher in the latter. Very little detail was provided to understand how the different costs were derived, but costs were likely based on the EPA CEMS Cost Model. For the Engine Test Cell NESHAP, a docket memorandum (Item II-B-9 of Air Docket A-98-29) indicates that the costs were determined using EPA's CEMS Cost Model Version 3.0, updated in 1998. The projected costs (20 years ago) include a first cost of $232,400, with an estimated annual cost of $69,000. These annual costs exceed the annual operating costs of the emissions control technology (*i.e.*, CEMS costs are higher than LEC and NSCR annual operating costs).

EPA considered the cost differential between CEMS and approaches based on parameter monitoring with periodic tests in several NESHAPs – and selected parameter monitoring as the preferred approach. Many examples are available where EPA concluded CEMS were not warranted and other compliance assurance measures were available (*i.e.*, parameter monitoring and/or testing) – *e.g.*, the Petroleum Refineries NESHAP for catalytic cracking units (CCU), the Mineral Wool NESHAP, and the Hospital/Medical/Infectious Waste Incinerator (HWI) NESHAP. EPA consistently concluded that parameter monitoring and/or periodic tests provided compliance assurance.

In addition, there is no evidence in the Proposed Rule docket to suggest that CEMS would provide any appreciable emissions control improvement as compared to parameter monitoring and periodic tests. Lacking any such evidence, it is clear that parameter monitoring and periodic tests provide compliance assurance, and CEMS are not warranted for T&S RICE.

5. Annual reporting, consistent with current permits for existing Title V facilities, is adequate.

The Proposed Rule would require semi-annual performance testing for affected RICE, with semi-annual reporting of data generated by the required performance testing. In contrast, federal and state air quality permits and related programs typically require annual reporting. This additional layer of reporting would result in requirements for affected units that differ from other annual facility reporting requirements, adding unnecessary complexity. Since the Proposed Rule is intended to address ozone season (*i.e.*, May through September) emission reduction, TC Energy recommends a single, annual tests rather than semi-annual testing and reporting. If EPA retains the semi-annual testing requirement, annual reporting is still adequate for conforming sources. If anomalous test results occur, EPA or the delegated authority could be informed of that situation through the test report submittal process.

<u>The Honorable Jeff Duncan</u>

1. **At the hearing, you noted how critical natural gas-fired generation is for balancing the intermittency of renewable energy. If we are to move towards the goal of a "zero-carbon power grid by 2035" like the Biden Administration wants to achieve, can you please elaborate on the importance of natural gas for electric reliability and affordability?**

Dispatchable generation, which is to say a source of electricity that can provide power on demand (like gas-fired generation), is absolutely critical for electric reliability. Non-dispatchable, intermittent wind and solar resources are weather-dependent and the time and quantity of their output cannot be controlled. They are incapable, by themselves, of ensuring the stability of the bulk electric system. They cannot meet the demands of the electric system when the wind does not blow, or the sun does not shine. They cannot stabilize the system on a real-time basis when clouds cover a large or critical area or wind speed unexpectedly drops. Technologically and economically feasible large-scale and long duration battery storage does not now exist to meet these shortfalls.[1] Battery storage facilities have a four-hour limit and may be unable to store sufficient energy to meet demand between recharge periods.[2]

For these reasons, the North American Electric Reliability Corporation (NERC), the entity responsible for establishing and enforcing reliability standards for the bulk

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[1] *See* New York Indep. Sys. Operator, Inc., *2023 Power Trends: A Balanced Approach to a Clean & Reliable Grid*, at 18 (2023), https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf/7f7111e6-8883-7b10-f313-d11418f12fbf ("It is especially important to note that commercially available technologies to provide dispatchable, non-emitting supply do not exist at scale at this time.") (NYISO Power Trends 2023).

[2] *See* NYISO Power Trends 2023 at 7 ("Energy Storage Resources (ESRs) offer great promise, but the amount of energy they can contribute to the grid, and the length of time they can perform, is limited today."); ISO New England Inc., *2021 Economic Study: Future Grid Reliability Study Phase 1*, at 47 (July 29, 2022), https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf (finding that in modeling certain future decarbonization scenarios, "the supply-and-demand mix . . . did not leave enough time for storage to recharge in the 2019 weather year, even though it was not a particularly severe winter") (ISO-NE 2022 Study).

electric system, has stated that natural gas is the "fuel that keeps the lights on"[3] and will remain so "until very large-scale and long duration battery deployments are feasible."[4] NERC has further advised that "natural gas policy must reflect this reality."[5]

Even attempting to reliably operate the bulk electric system in the face of the rapid retirement of dispatchable generation would require a substantial build-out of variable generation, energy storage, and transmission. This would inevitably cause electricity to become much more expensive. In a study published last year, ISO New England Inc. (ISO-NE) determined that under a deep decarbonization scenario approximately "89,900 MW in total wind, solar and storage versus the ~5,600 MW in use today" would be needed "to meet reliability criteria."[6] ISO-NE also commented that a deep decarbonization scenario "would require such a large amount of wind and solar that it may present significant challenges [to] the transmission system and require an outsized amount of land or offshore areas to be sited and developed for the necessary wind and solar farms."[7] However, with dispatchable units, ISO-NE concluded that the amount of variable generation, energy storage, and transmission would be reduced significantly, stating that "the substitution of 3,000 MW of dispatchable units . . . would reduce the necessary new units of wind, solar, and storage by 19% (17,000 MW)."[8]

New York Intendent System Operator, Inc. (NYISO) has found similarly, stating that to meet the goals of the state's decarbonization policies and expected peak demand "111-124 GW of generating capacity, or roughly three times the current capacity connected to the system" would be required by 2040 and that "27-45 GW of this capacity

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[3] James B. Robb, Written Testimony before the U.S. States Senate Committee on Energy & Nat. Resources, at 8 (June 1, 2023), https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11 (Robb Written Testimony); NERC, *2021 Long-Term Reliability Assessment*, at 5 (Dec. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf (2021 NERC Long-Term Reliability Assessment).

[4] Robb Written Testimony at 8-9.

[5] 2021 NERC Long-Term Reliability Assessment at 5.

[6] ISO-NE 2022 Study at 2-3.

[7] *Id.* at 3.

[8] *Id.*

must be from non-emitting resources capable of performing like today's fossil fuel-fired generation fleet depending on the scenario."[9] In addition, NYISO stated that "extensive transmission investments will be necessary to deliver renewable energy across the state to consumers and address new constraints that appear across the electric system resulting from significant new resource additions."[10]

a. We keep hearing that we need to build a lot more transmission if we want to decarbonize and ensure that we still maintain a reliable grid. Should we also be talking about the need to build more gas pipeline transmission?

Yes, policymakers should talk about how to build more natural gas pipelines to ensure the reliability of the bulk electric system. Policymakers should focus on both permitting *and* reforms to FERC-jurisdictional electric markets.

Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) have stated that the bulk electric system is becoming increasingly dependent on natural gas generation.[11] In order for natural gas-generators to reliably perform and serve load, they must have access to natural gas when called upon—that is, there must be pipeline capacity available to transport natural gas to generator facilities when and at the rate that natural gas is needed. Both NERC and the RTOs/ISOs have stated that

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[9] NYISO Power Trends 2023 at 18; *see also* Midcontinent Indep. Sys. Operator, Inc., *2022 Regional Resource Assessment*, at 9 (Aug. 24, 2022), https://cdn.misoenergy.org/20220824%20RASC%20Item%2006%20Regional%20Resource%20Assessment%20Presentation626035.pdf ("Due to lower projected accreditation values [for non-dispatchable resources], significantly more nameplate capacity is required to supply reserve requirements and accommodate goals.").

[10] NYISO Power Trends 2023 at 18.

[11] In his written testimony filed with the Senate, PJM Interconnection, L.L.C. (PJM) CEO and President Manu Asthana stated, "we are becoming increasingly dependent on natural gas. Additional [natural gas] pipelines will need to be sited to meet our reliability needs." Manu Asthana, Written Testimony before the U.S. Senate Committee on Energy & Nat. Resources, at 9 (June 1, 2023), https://www.energy.senate.gov/services/files/2098C524-7B71-4D39-BFF1-295E6E75BDB7 (Asthana Written Testimony).

additional natural gas pipelines are required.[12] However, as NERC President and CEO Jim Robb observed, "few . . . pipelines are actually being planned and built."[13]

Indeed, despite the abundance of domestic natural gas, round-the-clock access to the fuel is becoming ever more difficult. Not only has opposition to natural gas pipeline permitting intensified, federal agencies and state governments have actively obstructed infrastructure through delay and regulatory overreach.

States have also used the Clean Air Act permitting process to delay natural gas infrastructure in addition to using the Clean Water Act section 401 water quality certification process as a state veto. For instance, Iroquois Gas Transmission System, L.P.'s (Iroquois) air permits for its FERC-certificated Enhancement by Compression Project have been pending with the New York State Department of Environmental Conservation for over three years.[14] If federal authorizations are not timely issued, pipeline companies often cannot begin and complete construction in time to avoid demand shortfalls.

FERC itself has played a major role in obstructing the development of natural gas pipeline infrastructure. Starting in 2021, FERC staff, working under the direction of the then-Chairman, increased the length of the environmental review process by adopting a default procedure of preparing a full Environmental Impact Statement for all projects that produced even minimal quantities of incremental emissions, instead of the much shorter

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[12] Robb Written Testimony at 8 ("More transmission and natural gas infrastructure is required to improve the resilience of the electric grid."); *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (in his opening statement, PJM President and CEO Manu Asthana testified that "while most new entry is likely to be renewable plus batteries given the composition of our queue, we will also need new natural gas resources. And so whatever we do we need to be able to enable those and the infrastructure that supports them.").

[13] Robb Written Testimony at 8.

[14] *See* Marie J. French, *Pipeline owner pushes DEC to approve air permits in test of climate law*, POLITICO PRO (July 14, 2023).

Environmental Assessment which had sufficed previously.[15] This change of policy added, on average, five months or 68 percent to the time it took to conduct environmental reviews for the projects under consideration.[16] Further, FERC sought to completely rearrange the natural gas pipeline industry by imposing liability upon the pipeline companies for the downstream emissions caused by the end use of the natural gas that they transported and by changing the process by which project need would be established.[17] Although the two policy statements that sought to impose those changes have now been converted to drafts,[18] during the period of their pendency, natural gas pipeline companies operated under a cloud of profound regulatory uncertainty.[19] Unfortunately, because FERC has declined to close those dockets, that regulatory uncertainty persists.[20]

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[15] *See* Commissioner Danly November 29, 2021 Letter to Senator Barrasso, Docket Nos. CP20-27-000, et al., 8-13 (Accession No. 20211214-4001).

[16] Staff informed me that the average time to process an NGA section 7 certificate application from application filing to order issuance was 15.4 months in 2022 and 10.5 months in 2021.

[17] *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,107 (2022) (Danly, Comm'r, dissenting); *Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs.*, 178 FERC ¶ 61,108 (2022) (Danly, Comm'r, dissenting).

[18] *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,197, at P 2 (2022) (Danly, Comm'r, concurring in part and dissenting in part).

[19] *See Hearing to Review FERC's Recent Guidance on Nat. Gas Pipelines Before the S. Comm. on Energy and Nat. Res*. (March 3, 2022 Senate Hearing), 117th Cong. (2022) (Senator Barrasso quoted Alan Armstrong, the CEO of The Williams Companies, Inc., as stating the Interim GHG Policy Statement "has shrouded FERC certificate decisions in a fog of indecision.").

[20] *See, e.g.*, National Fuel Supply Corp., General Section 4 Rate Case Filing, Docket No. RP23-929 000, Ex. No. NFG-0074, at 133 of 144 (Accession No. 20230731-5076) (Prepared Direct Testimony of David J. Haag stating "[w]hile the draft policy statements remain pending before the Commission at this time, many of the changes contemplated would likely cause the construction of new or additional natural gas pipeline and storage facilities to become more difficult, requiring significantly longer lead times for review and approval. The uncertainty caused by these potential changes to

Permitting challenges are not the only reason that fewer pipelines serving gas generators have been completed. Gas-fired generators operating in RTOs and ISOs are effectively prohibited from procuring their gas through firm fuel contracts or signing precedent agreements necessary for pipelines to construct additional pipeline capacity. This is because markets do not ensure cost recovery for the acquisition of the total quantity of natural gas needed to maintain reliability. In the markets with capacity auctions, it would be probable that many (perhaps most) resources with round-the-clock firm fuel contracts would fail to clear the capacity auction because the competition from below-market (*i.e.*, government-subsidized) renewables would price them out of the market. The inevitable consequence of failing to clear the capacity auction would be that those generators would be deprived of the revenue needed to remain profitable and would be forced into retirement, notwithstanding the reliability benefits they provide.

Without the assurance of cost recovery, gas generators operating in RTOs and ISOs often rely on interruptible fuel contracts and capacity release contracts from local distribution companies. While such contracts may provide sufficient quantities of natural gas during normal conditions, they do not give gas-generators sufficient priority of service to ensure adequate supplies during periods of high demand (i.e., times of scarcity). This is often the very time when gas-generation is most needed to maintain electric reliability.

b. How important is natural gas-fired generation for resource adequacy and electric reliability?

NERC, the entity charged with assessing the reliability and adequacy of the bulk power system in North America,[21] has declared that "[n]atural gas is the reliability 'fuel that keeps the lights on'"[22] and "will remain essential to reliability for total energy and as a balancing resource . . . until very large-scale and long duration battery deployments are feasible or an alternative flexible fuel such as hydrogen, or small nuclear reactors can be

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the existing 20-year-old policy has increased regulatory uncertainty and raise the business risk of regulated natural gas pipelines and storage facilities, which will in turn impact the returns required by the market for investments in the natural gas pipeline and storage industry.").

[21] *See* 16 U.S.C. § 824*o*(g).

[22] 2021 NERC Long-Term Reliability Assessment at 5.

developed and deployed at scale."[23] In addition, nearly every RTO and ISO has stated that dispatchable generation must be retained to meet expected peak demand and reliably operate the bulk electric system.[24]

c. What are the obstacles to electric transmission projects that do not need federal subsidies or public funding?

The regulatory uncertainty created by the National Environmental Policy Act (NEPA) is a substantial barrier to transmission development needed for reliability and economic benefits. This is true everywhere, but it is particularly true in those parts of the

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[23] Robb Written Testimony at 8-9.

[24] *See* NYISO Power Trends 2023 at 17 ("Increasing levels of intermittent generation combined with increasing demand in response to electrification are expected to result in at least 17,000 MW of existing fossil-fueled generating capacity *which must be retained* to continue to reliably serve forecasted 'peak' demand days in 2030.") (emphasis added); *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (in his opening statement, PJM President and CEO Manu Asthana testified that "we will also need new natural gas resources"); ISO-NE 2022 Study at 56 ("If retired dispatchable generators are replaced by new non-dispatchable resources, this could create reliability issues."); MISO, Comments on Proposed Good Neighbor Plan, at 3 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0788 ("MISO is experiencing a trending decline in reserve margin, which is largely the result of the retirement of significant amounts of dispatchable generation."); Southwest Power Pool, Inc., Comments on Proposed Good Neighbor Plan, at 4 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0370 ("thermal resources continue to play a critical role in managing the variability of renewable resources and preserving system reliability."); Elec. Reliability Council of Tex., Inc., Comments on Proposed Good Neighbor Plan, at 5 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0434 ("Wind and solar generating units are, by definition, intermittent sources of generation. Solar energy dissipates fairly rapidly in the evening, creating a particular need for quick-ramping generation to offset the loss in solar power production. A sudden drop in wind in areas of the state heavy in wind generation can also create a need for substantial ramp capability. That capability must come from dispatchable forms of generation, such as gas and coal units.").

country where it is nearly impossible to build a transmission project of any length without crossing federal land. I am concerned that recent efforts at permitting reform, while making some improvement, have failed to sufficiently address the main problem that NEPA creates—the back-end litigation risk presented in every case by the very real chance that the federal court that sits in review of a transmission project's permits will vacate and remand those permits. Often, those vacaturs and remands have been based on no more than the court's perception that the federal agency insufficiently explained or explored some comparatively trivial issue in a complex infrastructure project.[25] Such flyspecking is virtually inevitable when all NEPA documents are subject to review under the Administrative Procedure Act's default arbitrary-and-capricious standard, a low and inconsistently applied threshold that allows for what amounts to a judicial veto on federal agency decisions. Time limits for agency action and page limits for NEPA documents do not and *cannot* address this central problem. Ironically, such well-intended efforts may ultimately harm infrastructure development by exacerbating litigation risks. Federal agencies respond to the incentives that litigation risk creates, so the increasing length of NEPA documents and the longer times that agencies take to conduct environmental reviews are often no more than a sincere, if sometimes misguided, effort to address this risk. Enforcing arbitrary time or page limits will reduce the agencies' ability to bulletproof the issuances that the agencies know will be subjected to the searching review that many federal courts apply to NEPA documents.

2. **Has the reliability of our bulk power system improved or worsened over the past 5 years?**

    a. **Please explain.**

The reliability of our bulk power system is getting worse. Reliability failures are becoming more likely as dispatchable fossil fuel generation resources prematurely retire because of public policies and market failures resulting from skewed price signals. You do not have to take my word for it. In June, the Senate Energy and Natural Resources

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[25] *See, e.g.*, *Wild Virginia v. U.S. Forest Serv.*, 24 F.4th 915, 927-29 (4th Cir. 2022) (vacating the Forest Service permit for the Mountain Valley Project in part for failing to consider "real-world data suggesting increased sedimentation along the Pipeline route" and for failing to wait for FERC to study the conventional boring method even though information in Forest Service's "supplemental [Environmental Impact Statement (EIS)] includes information about method, impact, safety, and environmental concerns related to convention boring"); *Sierra Club, Inc. v. U.S. Forest Serv.*, 897 F.3d 582 (4th Cir. 2018) (vacating Forest Service permit for the Mountain Valley Pipeline Project in part for failing to explain concern with sedimentation analysis).

Committee held a hearing on reliability. During this hearing, Jim Robb, the head of the North American Electric Reliability Corporation (NERC), in his opening testimony made the following statements:

- "the electric grid is operating ever closer to the edge where more frequent and more serious disruptions are increasingly likely;"
- "the foundation upon which the grid operates is out of balance;"
- "we are not making the required investments for reliability as the system transforms;"
- and there is "a general decline in the reliable generating capacity."[26]

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[26] *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (opening statement of NERC President & CEO Jim Robb); *see also* Robb Written Testimony at 10("The transmission system is indeed highly reliable, yet the aggregate electric system is threatened by a deteriorating risk profile."); NERC, *2023 Summer Reliability Assessment*, at 6 (May 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf (showing that much of North America has an elevated potential for shortfalls during the summer in "above-normal conditions"); Naureen S. Malik, *Summer Blackout Risks Extend to US Southeast for First Time*, BLOOMBERG LAW,(May 17, 2023), https://news.bloomberglaw.com/environment-and-energy/summer-blackout-risks-extend-into-us-southeast-for-first-time (quoting NERC's Director of Reliability Assessment, John Moura, as stated that "'[g]oing back at least five years, the reliability assessments have noted a steady deterioration in the risk profile of the grid'" and now, "[w]inter and summer assessments show 'the system is close to its edge'").

In addition, when asked if he agreed that "the United States is headed for a reliability crisis,"[27] Jim Robb replied, "I do."[28] PJM CEO Manu Asthana, at the same hearing, when asked whether he agrees that "the United States is heading for a reliability crisis,"[29] stated that "I do think there is an increasing risk of that."[30]

Other RTO/ISOs have also warned of declining reliability margins:

- NYISO in its recently published *Power Trends 2023* report stated that "[t]he retirement of fossil fueled resources driven by public polices is currently outpacing the development of new renewable energy and other dispatchable, emissions-free resources" the effect of which "is that reliability margins have thinned to concerning levels"[31] "most acutely in New York City."[32]

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[27] *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (statement of Senator Hoeven citing FERC Commissioners Mark Christie and James Danly).

[28] *Id.* (statement of NERC President & CEO Jim Robb).

[29] *Id.* (statement of Senator Hoeven citing FERC Commissioners Mark Christie and James Danly).

[30] *Id.* (statement of PJM President & CEO Manu Asthana); *see* Asthana Written Testimony at 6 ("If the rate of premature retirements continues to outpace the installation of replacement generation with the attributes necessary to maintain grid reliability, the nation may well face challenges with maintaining adequate supply to meet electric power demand.").

[31] NYISO Power Trends 2023 at 30.

[32] *Id.* at 8.

- Southwest Power Pool, Inc. (SPP) in its *2023 SPP Resource Adequacy Report* stated, "[t]he SPP BA Area Planning Reserve Margin is 20.1% for the 2023 Summer Season and decreases to 9.7% by planning year 2028."[33]

- Midcontinent Independent System Operator, Inc. (MISO) in its 2023 survey with Organization of MISO States (OMS) projected "a capacity deficit of 2.1 GW" in planning year 2025/26 and growing to a deficit of 9.5 GW in planning year 2028/2029.[34]

Both the head of NERC, the entity responsible for promulgating the nation's mandatory reliability standards, and wholesale electric markets agree with me: the current pace at which dispatchable generation is retiring threatens resource adequacy and system stability.[35]

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[33] SPP, *2023 SPP Resource Adequacy Report*, at 3 (June 15, 2023), https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf.

[34] OMS & MISO, *2023 OMS-MISO Survey Results*, at 2, 6 (July 14, 2023), https://cdn.misoenergy.org/20230714%20OMS%20MISO%20Survey%20Results%20Presentation629607.pdf.

[35] *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (NERC President & CEO, Jim Robb, when asked by Senator Hoeven if he agreed with FERC Commissioners Mark Christie and James Danly that that "the United States is headed for a reliability crisis,"[35] Jim Robb replied, "I do."); *id.* (PJM CEO Manu Asthana when asked if he agreed that "the United States is heading for a reliability crisis," stated that "I do think there is an increasing risk of that.").

b. If there are issues with the reliability of our grid, what policy decisions need to be made to improve reliability?

It is unquestionable that there are issues with the reliability of the bulk electric system. As stated by NERC President and CEO Jim Robb, "reliability needs to be prioritized in policy decisions."[36] What can and should FERC do?

First, the Commission should take immediate action under section 206 of the Federal Power Act (FPA)[37] to require RTOs/ISOs to show cause as to how their existing market structures are just and reasonable given existing price distortions and growing reliability concerns, and to impose replacement rates in those markets where the current rates are found to be unjust and unreasonable.

Second, the Commission should open inquires to explore (1) alternative mechanisms to ensure generators are compensated for the actual costs of providing power—including the cost of fuel to maintain reliability; and (2) potential market reforms that compensate generators only for the actual reliability benefits they provide.

Third, the Commission must not lose sight of a limits of our authority under the Natural Gas Act's (NGA) public convenience and necessity standard, nor should we lose sight of the how narrow the limits of our ratemaking powers are under the FPA. The Supreme Court has explained that the inclusion of the term "public interest" in the NGA and FPA is not "a broad license to promote the general public welfare"—instead, it "take[s] meaning from the purposes of the regulatory legislation."[38] The purpose of the Acts, as the Supreme Court has instructed us, is "to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices."[39] Efforts to expand

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[36] *Hearing to Examine the Reliability & Resiliency of Elec. Servs. in the U.S. in Light of Recent Reliability Assessments & Alerts Before the S. Comm. On Energy & Nat. Res.*, 118th Cong. (June 1, 2023), https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts (opening statement of NERC President and CEO Jim Robb).

[37] 16 U.S.C. § 824e.

[38] *NAACP v. FPC*, 425 U.S. 662, 669 (1976) (*NAACP*).

[39] *Id.* at 669-70 (citations omitted); *accord Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1307 (D.C. Cir. 2015) (quoting *NAACP*, 425 U.S. at 669-70). I note that the Supreme Court has also recognized the Commission has authority to

our jurisdiction beyond that narrow remit should be abandoned, except where Congress has declared otherwise. It is evident both from the text of the statute (and the Supreme Court's gloss) that the NGA does not confer the authority upon FERC to conduct backdoor environmental regulation from wellhead to burner tip. In order to restore regulatory certainty to the natural gas pipeline and electric industries we should immediately close the dockets on several of our open proceedings, including the now-draft Updated Certificate Policy and Interim GHG Policy Statements, both of which have been in draft form for well over a year.[40]

Although outside of FERC's authority, a final step that policymakers should immediately take is to repeal the subsidies upon which intermittent generators rely to remain profitable. Those subsidies are so lucrative that intermittent wind and solar generators typically offer into the capacity markets at a price of zero, in order to ensure that they clear the market. These artificially low offers suppress the capacity prices across the market, causing the market to clear at a lower capacity price, making it impossible for dispatchable fossil-fuel generators to clear if they bid their actual costs. The market thereby sends skewed price signals that make rational investment impossible and remove the very incentives the markets is supposed to rely upon to ensure resource adequacy. The inevitable result is the premature retirement of the dispatchable generators that actually support the reliable operation of the bulk electric system. Reliability crises and resource adequacy failures will follow.

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consider "other subsidiary purposes," such as "conservation, environmental, and antitrust questions." *NAACP*, 425 U.S. at 670 & n.6 (citations omitted). But all subsidiary purposes are, necessarily, subordinate to the statute's primary purpose.

[40] *See Consideration of Greenhouse Gas Emissions in Nat. Gas Infrastructure Project Revs.*, 178 FERC ¶ 61,108 (2022) (Interim GHG Policy Statement); *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,107 (2022) (Updated Certificate Policy Statement); *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,197, at P 2 (2022) (making the Updated Certificate Policy Statement and Interim GHG Policy Statement drafts).

c. **Will interregional transmission lines improve the reliability of our electric grid?**

As NERC stated in its *2022 Long-Term Reliability Assessment*, "most [transmission] project miles are initiated to support grid reliability."[41] However, NERC also stated that "projects for renewable integration are increasing."[42] This trend toward projects initiated for renewable integration will only continue—likely at an ever-increasing rate. Asset managers seeking to harvest the subsidies for renewable generation contained in the Inflation Reduction Act of 2022[43] cannot do so without the ability to interconnect their remotely located facilities to load. The National Renewable Energy Laboratory found that between 1,400 and 10,100 miles of additional new high-capacity lines *per year* would need to be added to transition to a generation fleet based on renewables.[44] To place that number in context, currently there are cumulatively 15,495 miles of transmission in construction or stages of development over the next 10 years.[45] It is worth repeating that weather dependent renewable generation does not have the reliability attributes necessary to ensure long-term system stability.

3. **How are ISOs/RTOs and wholesale electricity markets impacting the price and availability of dispatchable electricity generation?**

Wholesale electricity markets, with FERC's complicity, have suppressed prices and are driving existing dispatchable generation to early retirement. Because of this price suppression, there is little incentive for the entry of new generation with necessary reliability attributes. This situation is the result, in part, of the elimination of rules that

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[41] NERC, *2022 Long-Term Reliability Assessment*, at 22 (Dec. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf (2022 Long-Term Reliability Assessment).

[42] *Id.*

[43] Pub. L. No. 117-169, 136 Stat. 1818 (2022).

[44] National Renewable Energy Laboratory, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*, at xi (2022), https://www.nrel.gov/docs/fy22osti/81644.pdf.

[45] 2022 Long-Term Reliability Assessment at 22.

protected the market against market manipulation by subsidized renewable resources.[46] These resources use the subsidies to dump their "supply" into the market at artificially low prices (at an offer price of zero, in fact), thereby manipulating the downward-sloping demand curve to produce lower prices for all other supply.

If the price signals are distorted by external, price-suppressing subsidies, the capacity markets will be unable to send the accurate price signals needed to create incentives for a sufficient quantity of new capacity to meet system demand. Even worse, the external subsidies are designed to favor a particular category of resources (largely wind and solar) which do not have the reliability attributes necessary to ensure long-term system stability. To see the price-warping effects of government subsidies, one need to only look at the fact that although PJM has begun warning of impending generation scarcity, the prices in its most recent procurement auction went *down*.[47] Prices should increase as supply decreases under the downward-sloping demand curve, and they would be increasing if the market were not being manipulated to artificially reduce prices.[48]

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[46] *See, e.g.*, *ISO New England Inc.*, 179 FERC ¶ 61,139 (2022) (Danly, Comm'r, dissenting) (evisceration of minimum offer price rule); *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,102 (2022) (Danly, Comm'r, concurring in part and dissenting in part) (evisceration of buyer side mitigation); FERC Staff, September 29, 2021 Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (Accession No. 20210929-3009); *see also* Statement of Commissioner James P. Danly, Docket No. ER21-2582-000 (Oct. 27, 2021) (Accession No. 20211027-4003) (opposing the evisceration of the Minimum Offer Price Rule).

[47] *See* PJM Interconnection, L.L.C., PJM Capacity Auction Procures Adequate Resources, at 1 (Feb. 27, 2023), https://www.pjm.com/-/media/about-pjm/newsroom/2023-releases/20230227-pjm-capacity-auction-procures-adequate-resources.ashx ("The auction produced a price of $28.92 MW-day for much of the PJM footprint, compared to $34.13/MW-day for the 2023/2024 auction in May 2022 . . . .").

[48] *See, e.g.*, FERC Staff, September 29, 2021 Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (Accession No. 20210929-3009); *see also* Statement of Commissioner James P. Danly, Docket No. ER21-2582-000 (Oct. 27, 2021) (Accession No. 20211027-4003) (opposing the evisceration of the Minimum Offer Price Rule); *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,020 (2022) (Danly, Comm'r, dissenting) (opposing elimination of 10% adder in modeling energy market offers); Statement of Commissioner James P. Danly, Docket Nos. EL19-58-006, et al. (Jan. 20, 2022) (Accession No. 20220120-3114) (dissenting to order *PJM Interconnection, L.L.C.*,

Although we have yet to see the full effects of these policy decisions, they will inevitably have real-world consequences as the markets experience ever greater scarcity and are unable to attract the investment in the generation assets required to ensure that the electric system remains stable. Reliability failures will ultimately result, which is why FERC must act now to ensure the integrity of our markets by protecting them from the effects of subsidies.

a. What actions should Congress take to address that situation?

Congress should repeal market warping subsidies.

b. Are dispatchable generation, such as natural gas, coal, and nuclear, correctly valued in these wholesale electricity markets?

No, prices are too low for the markets to retain the existing (or attract new) dispatchable generation that is necessary to ensure reliability.[49] Wholesale electricity markets are allowing subsidized renewables to drive dispatchable generation out of business. This is most evident in PJM. Despite PJM's warnings of the impending scarcity of generation, the prices in its most recent procurement auction went *down*.[50] Prices should be increasing as supply decreases under the downward-sloping demand

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177 FERC ¶ 61,209 (2021), reversing recently approved reserve market reforms); *Indep. Mkt. Monitor for PJM v. PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,137 (2021) (Danly, Comm'r, dissenting), *order addressing arguments raised on reh'g*, 178 FERC ¶ 61,121 (2022) (Danly, Comm'r, dissenting) (opposing unit-specific mitigation review of all seller capacity offers).

[49] *See PJM's capacity-auction results signal continuation of troubling trends*, PJM Power Providers Group (June 22, 2022), https://www.p3powergroup.com/siteFiles/News/C90C8C039CF428BB732F77623B2E98FE.pdf.

[50] *See* PJM Interconnection, L.L.C., *PJM Capacity Auction Procures Adequate Resources*, at 1 (Feb. 27, 2023), https://www.pjm.com/-/media/about-pjm/newsroom/2023-releases/20230227-pjm-capacity-auction-procures-adequate-resources.ashx ("The auction produced a price of $28.92 MW-day for much of the PJM footprint, compared to $34.13/MW-day for the 2023/2024 auction in May 2022 . . . .").

curve, and they would be increasing if the market was not being manipulated by subsidized resources to artificially reduce prices.[51]

In addition, market rules are not structured to compensate generators for the actual costs of providing power—such as the cost of fuel. Gas-fired generators, by and large, are effectively prohibited from procuring their gas through firm fuel contracts. Assuming the gas-fired generators were permitted by the markets to offer their full costs, including the costs of their firm fuel contracts, it would be probable that, in the markets with capacity auctions, many (perhaps most) resources with round-the-clock firm fuel contracts would fail to clear the capacity auction because the competition from below-market renewables would price them out of the market.

The Honorable Michael Burgess, M.D.

1. **Are you concerned that the EPA Good Neighbor Rule that requires retrofits of many compressor engines in 20 states all before May 1, 2026, with only limited ability to request additional time could jeopardize the reliability of the grid?**

Yes, I am concerned that the implementation of the EPA's Good Neighbor Plan will contribute to the decline of the reliability of the nation's bulk electric system. The Good Neighbor Plan is one of several policies forcing the early retirement of flexible,

[51] *See, e.g.*, FERC Staff, September 29, 2021 Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (Accession No. 20210929-3009); *see also* Statement of Commissioner James P. Danly, Docket No. ER21-2582-000 (Oct. 27, 2021) (Accession No. 20211027-4003) (opposing the evisceration of the Minimum Offer Price Rule); *PJM Interconnection, L.L.C.*, 178 FERC ¶ 61,020 (2022) (Danly, Comm'r, dissenting) (opposing elimination of 10% adder in modeling energy market offers); Statement of Commissioner James P. Danly, Docket Nos. EL19-58-006, et al. (Jan. 20, 2022) (Accession No. 20220120-3114) (dissenting to order *PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209 (2021), reversing recently approved reserve market reforms); *Indep. Mkt. Monitor for PJM v. PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,137 (2021) (Danly, Comm'r, dissenting), *order addressing arguments raised on reh'g*, 178 FERC ¶ 61,121 (2022) (Danly, Comm'r, dissenting) (opposing unit-specific mitigation review of all seller capacity offers).

dispatchable generation without thoughtful consideration of when the retired generation will be replaced and with the necessary reliability attributes.[52]

The rule requires that by 2030 electric generating units (EGU) without selective catalytic reduction (SCR) controls must either install them or reduce generation during the five-month ozone season.[53] Based on the EPA's supporting analysis, some have projected that 79 coal-fired units totaling 42 GW of energy capacity (that is, over a fifth of existing coal generation)[54] do not have SCR technology.[55]

As EPA states, installing SCR technology is a "substantial investment."[56] Indeed, PacifiCorp estimated that "an SCR will cost from $150-200 million per unit . . . translat[ing] to nearly $1.5-2.0 billion dollars for the ten PacifiCorp units

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[52] *See, e.g.*, MISO, *Improvements to Att. Y Retirement Process*, at 2 (Apr. 27, 2022), https://cdn.misoenergy.org/20220427%20PAC%20Item%2005%20Improvements%20to%20Att%20Y%20Retirement%20Process%20Presentation624202.pdf (stating that "[a]mong other factors, Environmental Protection Agency (EPA) regulations" specifically the Coal Ash Regulations and the "Good Neighbor" Rule "are also rushing generation to retirement"); New York Indep. Sys. Operator, Inc., *2023 Power Trends: A Balanced Approach to a Clean & Reliable Grid*, at 11 (2023), https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf/7f7111e6-8883-7b10-f313-d11418f12fbf ("Adding to the challenge is pressure to eliminate fossil fuel generating resources from the grid, which has the net effect of causing generation to exit the grid faster than new resources can be added. The most pressing example of these forces is the New York State Department of Environmental Conservation's "Peaker Rule" . . . impacting approximately 3,300 megawatts (MW) of dispatchable and flexible electricity generation.").

[53] 88 Fed. Reg. 36,654, 36,762 (June 5, 2023).

[54] Energy Information Administration, *As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation* (Sept. 1, 2020) (stating that closures decreased the capacity to less than 200 GW).

[55] The National Rural Electric Cooperative Association, Comments on Proposed Good Neighbor Plan, at 15 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0409.

[56] 88 Fed. Reg. at 36,771.

potentially subject to the 2026 SCR requirement."[57] While some owners may install this technology, I am concerned (as have been nearly every Regional Transmission Organization (RTO) operating in affected states)[58]—that most will not. I find it hard to imagine that it would be economic to invest $150 million per unit when the next pollution control requirement—such as the recently issued proposed rulemaking requiring coal and

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[57] Berkshire Hathaway Energy Co., Comments on Proposed Good Neighbor Plan, at 29 n.78 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0554.

[58] MISO, Comments on Proposed Good Neighbor Plan, at 4 (June 21, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0788 ("MISO is concerned that the Proposed Rule could cause generator retirements due to the limitations on operations and/or the cost of installing Selective Catalytic Reduction ("SCR") and other technology improvements that may otherwise be required. Furthermore, to the extent units do not retire, their ability to operate could be limited by the Proposed Rule, which depending on the region and level of flexibility within the rule, could present a distinct reliability challenge."); Southwest Power Pool, Inc., Comments on Proposed Good Neighbor Plan, at 2 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0370 ("The Proposed Rule may impact approximately 40,000 MW of coal and gas generation in six states with assets operating in the SPP footprint.") (SPP Proposed Good Neighbor Plan Comments); *id.* ("SPP has concerns that any reduction in operations will pose a threat of reliability in the form of reduced generation capacity. Even without the impacts of the Proposed Rule, SPP has experienced scarce supply conditions and is predicting that those conditions will worsen over the coming planning horizon."); Elec. Reliability Council of Tex., Inc., Comments on Proposed Good Neighbor Plan, at 4-5 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0434 ("ERCOT understands that as much as 10,8000 MW of capacity in the ERCOT region—8,200 MW of coal-fired generation and 2,600 MW of gas-fired generation—is at risk of retirement due to the SCR mandate. . . . A significant increase in retirements of thermal generating units due to the Transport FIP will increase the likelihood that the generation supply in the ERCOT region will not be sufficient to serve customer load."); PJM, Comments on Proposed Good Neighbor Plan, at 14 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0412 ("The concurrent risk, however, is that units may choose to retire (deactivate) or be unable to operate due to an emissions-related operational limitation.") (PJM Proposed Good Neighbor Plan Comments).

gas-fired power plants to limit greenhouse gases[59]—will shut down operations within ten years. What does this mean? Reduced dispatchable generation capacity, either from outright retirement or forced reduced output, when most of the country is already, or soon will be, experiencing severe shortages of generation capacity.

Based on false assumptions, the EPA denies that the Good Neighbor Plan "would threaten resource adequacy or otherwise degrade electric system reliability"[60] and declines to establish a reliability safety valve to address short-term declared system emergencies.[61] The EPA *assumes* the retired or reduced generation will be adequately replaced by 2030.[62] This is highly unlikely. It takes significant time to obtain regulatory approvals to construct new generation and needed transmission facilities. SPP stated that in its footprint, "it can take up to *ten years or more* to plan, approve, and construct

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[59] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (proposed May 23, 2023) (to be codified at 40 CFR part 60, subpart UUUUb); *see also* Patrick O'Loughlin, President and Chief Executive Office for Buckeye Power, Inc. and Ohio Rural Electric Cooperatives, Before the U.S. House Committee on Energy and Commerce, Hearing on Clean Power Plan 2.0: EPA's Latest Attack on America's Electric Reliability, at 3 (June 6, 2023), https://d1dth6e84htgma.cloudfront.net/06_06_23_Testimony_O_Loughlin_a1b32514ac.pdf?updated_at=2023-06-05T13:27:30.695Z ("If enacted, [the rule] will jeopardize nearly every coal-fired power plant by 2039 and most by 2030. . . . Buckeye Power will be required to shut down all of our coal-fired units by 2030 with no hope of nearly replacing this energy within that timeframe.").

[60] 88 Fed. Reg. at 36,771.

[61] *Id.* at 36,774 ("The EPA is not adopting the suggestion to replicate the so-called 'safety valve' mechanism . . . .").

[62] *Id.* at 36,771 ("[S]ome EGU owners will conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new controls at the unit."); *id.* at 36,772 ("where an EGU would prefer to *retire and replace* an uncontrolled EGU rather than to install new controls") (emphasis added).

transmission facilities that would be required for new generation."[63] Moreover, as the Commission's recently issued Interconnection Rule acknowledges, generating facilities that were built in 2022 had to wait "*roughly five years*" to interconnect to the transmission system.[64]

EPA further *assumes* that "any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected."[65] There is *no* basis for such an assumption. As PJM informed the EPA, "PJM cannot direct the construction or operation of particular generating units nor require upgrades to those generation units" and that "[r]egardless of whether deactivating the generating unit would adversely affect the reliability of the transmission system, the generator may deactivate its generating unit, subject to the notice requirements in the PJM Tariff."[66] As for state regulators, some state public utility commissions have limited to no authority over merchant generators.[67] While the operators of the bulk electric system are extremely capable and will doubtless do their best to minimize disorder as they lose the dispatchable generation assets upon which they depend to ensure reliability, they cannot be expected to do the impossible. Depending on the pace of retirements, the situation facing balancing authorities across the country is akin to that of the crew of the Titanic attempting to ensure an orderly evacuation of a ship with insufficient lifeboat capacity—at some point, the problem becomes insoluble.

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[63] SPP Proposed Good Neighbor Plan Comments at 4 (emphasis added).

[64] *Improvements to Generator Interconnection Procedures & Agreements*, 184 FERC ¶ 61,054, at P 39 (2023) (emphasis added); *see also* Evergy, Inc., Comments on Proposed Good Neighbor Rule, at 11 (June 20, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0302 (commenting on long RTO backlogs to approve new generation additions).

[65] 88 Fed. Reg. at 36,771.

[66] PJM Proposed Good Neighbor Plan Comments at 4.

[67] National Association of Regulatory Utility Commissioners, *Resource Adequacy Primer for State Regulators*, at 50 n.61 (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042 ("Some state public utility commissions have authority only over [investor-owned utilities], whereas other states do have jurisdiction over publicly owned utilities.").

To make matters worse, the Good Neighbor Plan will constrain (in some regions, further constrain) the natural gas system, limiting access to fuel for gas-fired generators. The rule requires that certain non-electric compressor units used to transport gas through the interstate pipeline system—which the Interstate Natural Gas Association of America (INGAA) estimated in its comments on the proposed rule amounts to 1,380 units[68]—*all* have new pollution controls installed by 2026. The rule does not stagger compliance. It does not permit pipelines to coordinate when units will be taken offline.

Put simply, pipelines will have to take affected units offline *simultaneously*, reducing throughput throughout the nation because the natural gas pipeline system is highly integrated. As stated by a natural gas pipeline company, "[w]ith pipeline engines for multiple companies being off-line at the same time, the options for temporarily re-routing the flow of natural gas to end users could be severely limited and threaten the overall reliability of our nation's pipeline grid."[69]

Throughput will not simply be reduced for a short duration during non-peak periods. Pipeline companies informed the EPA that there are "very few manufacturers [that are] capable of retrofitting units"[70] and that one of the manufacturers "indicated that it would only be able to modify 20 or 30 Engines a year, across all of industry."[71] One pipeline company identified data from a past EPA rulemaking that "demonstrates that only about 75 engines a year can be retrofitted on a sustained basis."[72] If there are 1,380 affected units and only 75 can be retrofitted each year, that would mean it would take *over 18 years* to retrofit all of the affected compressor units, extending over 34 peak

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[68] INGAA, Comments on Proposed Good Neighbor Plan, at 9 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0501. In its Motion for Stay of the final Good Neighbor Plan, INGAA stated that its "members believe that approximately 1,220 pipeline engines will require controls to comply with the Final Rule." INGAA & American Petroleum Institute Motion for Stay, Yager Dec. ¶ 9, No. 23-1193, July 27, 2023 (INGAA Motion for Stay).

[69] *See id.* Tarr Dec. ¶ 11.

[70] *See, e.g.*, Kinder Morgan, Comments on Proposed Good Neighbor Plan, at 36 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0350.

[71] *Id.* at 28.

[72] TC Energy, Comments on Proposed Good Neighbor Plan, at 2 (June 21, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0380.

winter and summer seasons. Pipeline companies, however, do not have 18 years to come into compliance. The Good Neighbor Plan requires compliance within 31 months, by May 1, 2026, with some extensions given on a case-by-case basis.[73] If pipelines cannot comply by the deadline, hundreds of compressor units are expected to remain idle for over a decade. The effect of throughput reduction will be most acutely felt in regions already experiencing supply constraints. Areas like New England are already severely constrained and cannot afford to have *any* capacity taken offline.

Moreover, the Good Neighbor Plan's effects on residential natural gas customers (71.9 million in 2021)[74] cannot be overlooked. According to Kinder Morgan, Inc. (Kinder Morgan), in order to comply with the rule on just one segment of its Natural Gas Pipeline Company of America LLC pipeline, which "provides approximately 60 percent of the natural gas to the Chicago market," it would have to fail to provide 587,000 Dekatherms per day of natural gas that "equates to an inability to provide the natural gas necessary to heat approximately 1,761,000 homes" and would result in a "20 percent overall deficit in meeting the Chicago market peak demand on winter days."[75] Again, the effect of this throughput will be most acutely felt in regions already experiencing supply constraints.[76]

Although EPA responds to arguments regarding how the EGU portion of its rule affects electric reliability, to my knowledge, the EPA does not ever consider the impacts that the timeline for compliance for non-EGUs would have on electric reliability or

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[73] 88 Fed. Reg. at 36,760 (discussing how first and second compliance extension requests will be evaluated).

[74] Energy Information Administration, Number of Natural Gas Consumers, https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm.

[75] INGAA Motion for Stay, Grubb Dec. ¶ 66.

[76] For example, during Winter Storm Elliot, the local distribution companies serving New York City requested that customers reduce natural gas usage because of interstate natural gas pipeline disruptions. *See* Con Edison, *Con Edison Urges Customers to Conserve Energy Due to Heavy Demand on Interstate Gas Pipelines* (Dec. 24, 2022), https://www.coned.com/en/about-us/media-center/news/2022/12-24/con-edison-urges-customers-to-conserve-energy--due-to-restrictions-on-interstate-gas-pipelines; National Grid, *National Grid Asks All Customers in Downstate New York to Immediately Reduce Gas Usage* (Dec. 24, 2022), https://www.nationalgridus.com/News/2022/12/National-Grid-Asks-All-Customers-in-Downstate-New-York-to-Immediately-Reduce-Gas-Usage/.

residential uses. EPA's failure to do so runs counter to Executive Order 13211 which directs agencies to consider the effects of their regulations on "the supply, distribution, and use of energy."[77]

2. Did EPA consult with the FERC on impacts to reliability from the Good Neighbor Rule?

Consultation and communication between FERC and other federal agencies typically occur at the FERC staff level, as supervised by the Chairman.[78] At my request, FERC staff informed me that its only contact with the EPA regarding the Good Neighbor Plan was in 2022 to discuss comments received by affected RTOs and Independent System Operators. The EPA did not ask any question about how requiring nearly 1,400 natural gas compressor stations to be replaced or retrofitted within a narrow window could reduce already constrained capacity and affect electric reliability. I am also not aware of the Office of Management and Budget's Office of Information and Regulatory Affairs consulting with FERC on the consequences the rule would have on the supply, distribution, and use of energy as required by Executive Order 13211.[79]

FERC recently announced it will convene a technical conference on November 9, 2023, to discuss the projected electric reliability consequences of the EPA's proposed rulemaking requiring coal and gas-fired power plants to limit greenhouse gases.[80] My hope is that as part of those conferences, reliability effects of the Good Neighbor Plan will be evaluated, and solutions identified.

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[77] E.O. 13211 (May 21, 2001).

[78] *See* 42 U.S.C. § 7171(c) ("The Chairman shall be responsible on behalf of the Commission for the executive and administrative operation of the Commission, including . . . the supervision of personnel employed by or assigned to the Commission.").

[79] E.O. 13211, § 2(c).

[80] FERC, Notice of Reliability Technical Conference, Docket No. AD23-9-000 (Aug. 3, 2023); *see also* U.S. Senators John Barrasso & Shelley Moore Capito, June 30, 2023 Letter to FERC Chairman Phillips and Commissioners (Accession No. 20230703-4000) (requesting FERC convene a technical conference).

The Honorable Bill Johnson

1. **It appears that all interstate pipelines other than water pipelines are subject to one of three federal laws. The (1) Natural Gas Act provides FERC jurisdiction over the interstate transportation of "natural gas," 15 U.S.C. § 717, the (2) Interstate Commerce Act provides FERC jurisdiction over the interstate transportation of "oil," 49 U.S.C. app. §§ 1, et seq. (1988), and the (3) Interstate Commerce Commission Termination Act provides the Surface Transportation Board with jurisdiction over the interstate transportation of "commodit[ies] other than water, gas, or oil." 49 U.S.C. § 15301(a).**

    a. **There is a substantial amount of precedent interpreting each of these statutory terms, both from the agencies and the courts. Which of these statutes do you believe applies to interstate hydrogen pipelines, and why?**

As a FERC Commissioner, I am not well situated to offer counsel on the precedent regarding the Surface Transportation Board's (STB) jurisdiction under the Interstate Commerce Commission Termination Act.

As for the applicability of the Interstate Commerce Act (ICA) or the Natural Gas Act (NGA)to hydrogen pipelines, the Commission has not had occasion to evaluate the issue directly. In my view, hydrogen pipelines are unlikely to be subject to either statute and the Commission very probably lacks jurisdiction.

To evaluate whether the Commission has jurisdiction under the ICA, the Commission would have to determine whether the hydrogen pipeline "engaged in . . . [t]he transportation of oil or other commodity, except water and except natural or artificial gas, by pipe line, or partly by pipe line and partly by railroad or by water."[81] The Commission makes this finding by evaluating "(1) whether the commodity is a fuel source in that it has heating value and is used for energy-related purposes; (2) whether the

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[81] 49 U.S.C. § 1(1). Congress subsequently passed the Department of Energy Organization Act (DOE Act) in 1977, which transferred to FERC "such functions set forth in the [ICA] and vested by law in the Interstate Commerce Commission or the Chairman and members thereof as relate to transportation of oil by pipeline." Pub. L. No. 95-91, § 306, 91 Stat. 565, 581 (1977); *see also* 49 U.S.C. § 60502; *see also CF Indus., Inc. v. FERC*, 925 F.2d 476 (D.C. Cir. 1991) (discussing FERC's authority under the DOE Act).

cost of transportation will have an impact on energy markets; and (3) whether the commodity will compete with oil or other refined products for capacity in the pipeline."[82]

The Department of Energy states that hydrogen is currently transported by pipeline in its gaseous state in regions with substantial demand and by truck in either its liquid or gaseous state in regions where demand is smaller or emerging.[83] The most recent jurisdictional determination came from the former Interstate Commerce Commission (ICC) which held that "Congress intended to exclude from [its] jurisdiction [under the ICA] all gas types regardless of origin or source."[84] Hydrogen, if transported by pipeline, would be virtually certain to be transported as a gas—to do so as a liquid would require it (assuming standard pressures) to be cooled to and kept below -423°F (20° K).[85] Under the ICC's holding, therefore, hydrogen transportation by pipeline would be non-jurisdictional.

Nevertheless, if the transportation of hydrogen by pipeline is found to fall within the jurisdiction conferred by the ICA, hydrogen pipelines would become common carriers, meaning that hydrogen pipelines would have to offer to transport hydrogen at the same rates and terms to all interested shippers. Hydrogen pipelines could not agree to negotiated rates for specific shippers. In addition, the Commission would only have authority to regulate the rates and services of hydrogen pipelines; the Commission would have no power to site hydrogen pipelines or authorize a certificate for a hydrogen pipeline that conveys eminent domain authority.

To determine whether hydrogen pipelines are jurisdictional under the NGA, the Commission would have to determine whether the pipeline engaged in the "transportation of natural gas in interstate commerce."[86] The NGA defines "natural gas" as meaning

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[82] *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090, at P 30 (2015) (discussing *Gulf Cent. Pipeline Co*., 50 FERC ¶ 61,381 (1990), *aff'd, CF Indus., Inc. v. FERC*, 925 F.2d 476).

[83] *Hydrogen Delivery*, DEPARTMENT OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-delivery (last visited Aug. 1, 2023).

[84] *Cortez Pipeline Co.*, 45 Fed. Reg. 85,177, 85,178 (Dec. 24, 1980).

[85] *Liquid Hydrogen Delivery*, DEPARTMENT OF ENERGY, https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery (last visited Aug. 1, 2023).

[86] 15 U.S.C. § 717(b).

"natural gas unmixed, or any mixture of natural and artificial gas."[87] The Commission does not have jurisdiction over pipelines transporting purely artificial gas, that is, when "the product gas is artificially created by the agency of man."[88] Hydrogen is an artificial gas.[89]

Further, the Commission only assumes jurisdiction over pipelines when doing so would advance a goal or purpose of the NGA[90]—that is, when it would be consistent with the NGA's objective of "encourag[ing] the orderly development of plentiful supplies of . . . natural gas at reasonable prices."[91] Based on this analysis, FERC has found that a pipeline transporting predominantly carbon dioxide in interstate commerce which produced a small amount of methane that was never separated or sold was not within its jurisdiction.[92] A similar analysis would likely apply to hydrogen pipelines and the Commission would, therefore, likely lack jurisdiction under the NGA.

If, however, the Commission is found to have jurisdiction over hydrogen pipelines under the NGA, the transportation and sale of hydrogen will be considered as "affected with a public interest."[93] In addition, the Commission will have authority to conduct

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[87] *Id.* § 717a(5).

[88] *Nat. Gas Pipeline Co. of Am.*, 53 FPC 802, 804 (1975).

[89] *Hydrogen Production*, Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-production (last visited Aug. 1, 2023) (stating that hydrogen "doesn't typically exist by itself in nature and must be produced from compounds that contain it.").

[90] *See Cortez Pipeline Co.*, 7 FERC ¶ 61,024, at 61,041 (1979) (stating that the issue of how to define "natural gas" "should be determined primarily by reference to the goals and purposes of the NGA") (citations omitted). The Supreme Court counsels that "[i]n determining the meaning of the statute, [one] look[s] not only to the particular statutory language, but to the design of the statute as a whole and to its object and policy." *Crandon v. United States*, 494 U.S. 152, 158 (1990) (citations omitted).

[91] *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976) (citations omitted).

[92] *Cortez Pipeline Co.*, 7 FERC ¶ 61,024.

[93] 15 U.S.C. § 717(a).

hearings concerning the lawfulness of rates,[94] investigate market manipulation in connection with the purchase or sale of hydrogen or transportation services,[95] fix rates and charges,[96] regulate the construction of hydrogen pipeline facilities and abandonment of transportation and service,[97] facilitate price transparency in those markets,[98] and subject pipelines to penalties of up to $1,000,000 per day per violation of "any rule, regulation, restriction, condition, or order made or imposed by the Commission."[99] Hydrogen pipelines, once certificated, would also be accorded the right to acquire land by the exercise of eminent domain—a formidable power.[100]

I acknowledge that there is interest in hydrogen given the subsidies in the Inflation Reduction Act[101] and the Environmental Protection Agency's recently published proposed rulemaking on New Source Performance Standards for Greenhouse Gases that in effect mandates the installation of carbon sequestration technology or the co-firing of hydrogen.[102] However, many have stated that the transportation of hydrogen in interstate gas pipelines is not without its challenges. The Congressional Research Service (CRS) has described how hydrogen, due to its molecular size, is more prone to leaking from pipelines than methane and can also cause "embrittlement" of the materials from which

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[94] *Id.* § 717c.

[95] *Id.* § 717c-1.

[96] *Id.* § 717d.

[97] *Id.* § 717f(b), (c).

[98] *Id.* § 717t-2.

[99] *Id.* § 717t-1(a).

[100] *Id.* § 717f(h).

[101] Pub. L. No. 117-169, 136 Stat. 1818 (2022).

[102] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (proposed May 23, 2023) (to be codified at 40 CFR part 60, subpart UUUUb).

natural gas pipelines are commonly constructed.[103] This embrittlement "can lead to acute pipeline failure or may generally reduce the service life of a pipeline."[104] While there may be ways to develop new pipelines that are suited to a hybrid role, the CRS concludes that "[w]hen hydrogen is introduced into pipelines originally designed to transport natural gas . . . [it] can create greater safety risks than those in dedicated hydrogen pipelines."[105]

As a final matter, it is worth noting that hydrogen has a number of physical characteristics that may make it impractical as a replacement for natural gas or other hydrocarbons in the economy, at least on a significant scale. "Hydrogen has the highest energy content of any common fuel by weight . . . , but it has the lowest energy content by volume."[106] This has serious implications for the practicality (and commercial viability) of transporting large volumes of hydrogen over substantial distances. Pipeline capacity is scarce and therefore valuable. The opportunity costs of transporting a low energy density fuel, necessarily displacing higher energy density fuel in the process, would likely raise the overall cost of energy significantly.

Also, "it takes more energy to produce hydrogen (by separating it from other elements in molecules) than hydrogen provides when it is converted to useful energy."[107] This raises profound questions about the practicality of producing the quantities of hydrogen that would be needed for a "hydrogen economy." A vast amount of surplus energy would be needed to supply enough hydrogen to replace natural gas.[108]

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[103] Congressional Research Service, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy*, at 3 (Mar. 2, 2021), https://crsreports.congress.gov/product/pdf/R/R46700.

[104] *Id.*

[105] *Id.* at 4.

[106] *Hydrogen explained*, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/energyexplained/hydrogen/ (last visited Aug. 1, 2023).

[107] *Id.*

[108] For more on the practical limitations of hydrogen see Michael Liebreich, *The Unbearable Lightness of Hydrogen*, BloombergNEF (Dec. 12, 2022), https://about.bnef.com/blog/liebreich-the-unbearable-lightness-of-hydrogen/.

Since it appears, at best, questionable that hydrogen pipelines would be jurisdictional under either the NGA or the ICA, if Congress wants hydrogen pipelines to be subject to federal regulation, it should consider legislation to unambiguously assign that jurisdiction to some agency.

b. Additionally, what is FERC's jurisdiction for intrastate hydrogen pipelines today?

While FERC has not been presented with such issue, it is unlikely that FERC would have jurisdiction over intrastate hydrogen pipelines. As I discuss above, it is at best questionable that the transportation of pure hydrogen would be jurisdictional under either the NGA or the ICA. Furthermore, the NGA specifically excludes the transportation of natural gas in intrastate commerce from FERC's jurisdiction.[109] Similarly, "there is no dispute that FERC lacks a general regulatory power over oil in intrastate commerce" under the ICA.[110]

2. **You wrote in September 2021, you discussed your quote, "lingering apprehension that the Commission may not actually have authority to oversee the safety of liquefied natural gas (LNG) facilities under section 3 of the Natural Gas Act (NGA)…." And you noted that quote "there is no language in the NGA that explicitly grants power to either the Commission or the Department of Energy to take responsibility for LNG safety."**

    a. **Can you share with the committee your perspective on FERC's authority for LNG safety and the cause of your apprehension? Are you still concerned about the Commission's interpretation of its authority?**

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[109] 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply to any other transportation or sale of natural gas or to the local distribution of gas"); *Associated Gas Distributors v. FERC*, 899 F.2d 1250, 1255 (D.C. Cir. 1990) ("FERC lacks jurisdiction over the transportation of gas in intrastate commerce; the states regulate such transportation").

[110] *Tesoro Alaska Co. v. FERC*, 778 F.3d 1034, 1039 (D.C. Cir. 2015).

I am concerned about duplication of efforts from multiple federal agencies here.

I continue to have misgivings regarding the Commission's claim of ongoing jurisdiction over the safety of liquefied natural gas (LNG) facilities.[111] Like you, I am concerned that the Commission is either duplicating the efforts, or unilaterally assuming the statutory responsibilities, of the Department of Transportation to which Congress has granted unambiguous authority to regulate the safety of LNG facilities.[112]

Before I further explain the cause of my apprehension, it may be helpful to provide an overview of the statutory authority up which I *assume* the Commission bases its wide ranging and comprehensive LNG safety program. I emphasize "assume" as there is no language in the Natural Gas Act (NGA) that explicitly grants power to either the Commission or the Department of Energy (which delegates authority to the Commission)[113] to take responsibility for LNG safety, and to my knowledge, the Commission has never explained why it believes it can exercise this jurisdiction in any of its orders.

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[111] *See Freeport LNG Dev., L.P.*, 180 FERC ¶ 61,055 (2022) (Danly, Comm'r, concurring at P 5) ("I have continued misgivings regarding the Commission's claim of ongoing jurisdiction over the safety of liquefied natural gas facilities") (citation omitted); *EcoEléctrica, L.P.*, 180 FERC ¶ 61,054 (2022) (Danly, Comm'r, concurring at P 2) ("I write separately to express my continued misgivings regarding the Commission's claim of ongoing authority to oversee the safety of LNG facilities) (citation omitted); *EcoEléctrica, L.P.*, 179 FERC ¶ 61,038 (2022) (Danly, Comm'r, concurring) ("I write separately to express my continued misgivings regarding the Commission's authority to oversee the safety of liquefied natural gas facilities") (citation omitted); *EcoEléctrica, L.P.*, 177 FERC ¶ 61,164 (2021) (Danly, Comm'r, concurring at P 1) ("I have a lingering apprehension that the Commission may not actually have the authority it has exercised over the safety of LNG facilities under section 3 of the NGA").

[112] *See* 49 U.S.C. § 60103.

[113] *See* DOE, Delegation to the Fed. Energy Regulatory Comm'n, Delegation Order No. S1-DEL-FERC-2006, § 1.21A (May 16, 2006).

Presumably, the Commission asserts jurisdiction over the safety of LNG terminals[114] from the language in NGA section 3 which gives the Commission "exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal"[115] "with such modifications and upon such terms and conditions as the Commission find necessary or appropriate."[116] The Commission also asserts jurisdiction over the safety of LNG peak shaving facilities,[117] presumably under NGA section 7 which provides that "a certificate shall be issued . . . if it is found that . . . the proposed . . . operation . . . is or will be required by the present or future public convenience and necessity" and that the Commission may "attach to the issuance of the certificate . . . reasonable terms and conditions as the public convenience and necessity may require."[118]

In my view, basing the Commission's LNG safety program on these provisions is, at best, questionable. If the provision in NGA section 3 is indeed the provision of the statute upon which we rely to regulate the safety of LNG terminals, it simply cannot be that Congress intended the Department of Energy or the Commission to have "exclusive authority" over all aspects of LNG terminal operations, including safety, because Congress has explicitly conferred jurisdiction over LNG safety upon the Department of Transportation.[119]

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[114] The NGA defines LNG Terminal as natural gas facilities that "receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States or transported in interstate commerce by waterborne vessel." 15 U.S.C. § 717a(11).

[115] *Id.* § 717b(e)(1) (emphasis added).

[116] *Id.* § 717b(e)(3)(A).

[117] Peak shaving LNG facilities typically have less capacity than an import and export LNG terminal and are located along the pipeline system to ensure adequate supplies of natural gas when demand is at its peak. *See LNG Facility Siting*, PIPELINE & HAZARDOUS MATERIALS SAFETY ADMINISTRATION, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-facility-siting (last visited Aug. 1, 2023).

[118] 15 U.S.C. § 717f(e).

[119] *See* 49 U.S.C. § 60103.

Likewise, the Commission interprets NGA section 7 differently depending upon the facility at issue. LNG peak shaver facilities are NGA section 7 facilities over which the Commission asserts jurisdiction for operational safety.[120] However, the Commission does not consider NGA section 7 as empowering it to regulate the operational safety of interstate natural gas pipeline facilities.[121] How can the same language be applied differently based on the type of facilities at issue when the statute itself makes no distinction?

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[120] *See Chattanooga Gas Co.*, 51 F.P.C. 1278, 1279 (1974).

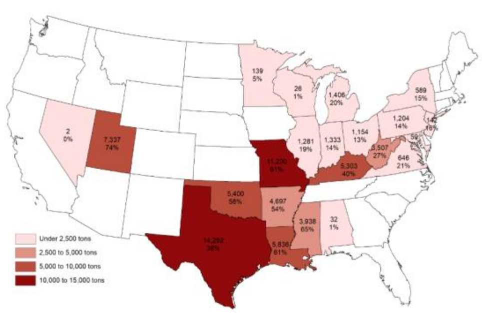
[121] *See Mountain Valley Pipeline*, LLC, 171 FERC ¶ 61,047, at P 21 n.62 (2020) ("We also note that the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration's (PHMSA) has the exclusive authority to promulgate and enforce safety regulations and standards for 'the design, installation, construction, initial inspection, initial testing, operation, and maintenance of facilities used in the transportation of natural gas."') (citing Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Natural Gas Transportation Facilities, http://www.ferc.gov/legal/mou/mou-9.pdf).

Exhibit Showing EPA's Expected Emissions Reductions

	Emission Reductions (Tons); States With Stays	Emission Reductions (% of Total); States Without Stays	Emission Reductions (Tons); States Without Stays	Emission Reductions (% of Total); States Without Stays	Emission Reductions; Total (Tons)
EGU	61,673	89%	7,840	11%	69,513
Non-EGU	26,897	60%	17,718	40%	44,615
Total (EGU and Non EGU)	88,570	78%	25,558	22%	114,128

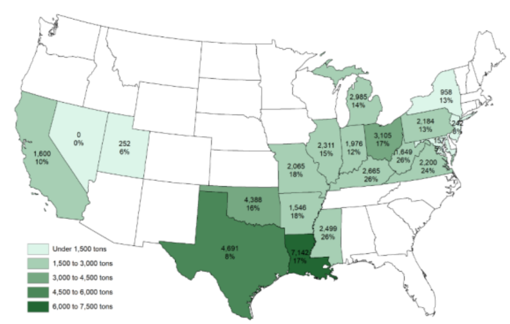
Source: Good Neighbor Plan for 2015 Ozone NAAQS (available at https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs); Overview Fact Sheet, EPA's "Good Neighbor Plan" Response to Comply with Stay Orders Pending Judicial Review, September 21, 2023. In particular, these maps:

Power Plant Ozone Season Emissions Reductions in 2027 Relative to 2021 Under the Final Good Neighbor Plan



The estimated emissions reductions reflect the difference between the rule's preset 2027 budgets for EGUs (this may vary based on the dynamic budget level) and adjusted current 2021 emissions for those EGUs (2021 reported emissions are adjusted to account for known or planned changes such as: retirement, planned retirement, coal-to-gas conversion, etc.). Because these estimated reductions reflect the overall change from current emissions, they are higher, on average, than the values reflected in the regulatory impact analysis (emissions reductions relative to projected future baseline emissions) and other communications materials.

Industrial Source Ozone Season Emissions Reductions in 2026 Relative to 2019 Under the Final Good Neighbor Plan



The estimated percent reductions are calculated using total 2019 non-EGU emissions, including non-EGU point source emissions, oil and gas point source emissions, and the MWC portion of EGU emissions.

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

KINDER MORGAN, INC., Petitioner, v. U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S. REGAN, Administrator, U.S. EPA Respondents.	Case No. 23-1181

DECLARATION OF KENNETH W. GRUBB IN SUPPORT OF KINDER MORGAN INC.'S MOTION TO STAY THE FINAL RULE OF THE U.S. ENVIRONMENTAL PROTECTION AGENCY PENDING REVIEW

I, Kenneth W. Grubb, declare the following is true and correct:

1. I am Chief Operating Officer for the natural gas pipelines business unit at Kinder Morgan, Inc. (Kinder Morgan), one of the largest energy infrastructure companies in North America and one of the largest natural gas transporters and natural gas storage operators in North America. I have worked for Kinder Morgan for 33 years, with roles in Market Development, Project Management, Construction, System Design, and Operations.

2. I have a Bachelor of Science degree in Electrical Engineering from Oklahoma State University. In my 33 years with Kinder Morgan, I have held various

engineering and leadership roles. For the last eleven years, I have held senior level leadership roles within the natural gas pipeline business unit's operations department. As Chief Operating Officer of natural gas pipelines, my primary responsibility is to ensure safe, reliable, compliant, and efficient operations of the natural gas pipeline network. Part of my responsibilities include helping Kinder Morgan with environmental regulatory compliance, including emissions regulations affecting Kinder Morgan's operations.

3. I am over 21 years of age. This declaration is based on my personal knowledge and analysis conducted by Kinder Morgan personnel and me.

4. I am providing this declaration in support of Kinder Morgan's motion to stay the U.S. Environmental Protection Agency's (EPA) Final Rule adopting a federal implementation plan (FIP) for the 2015 ozone National Ambient Air Quality Standards. 88 Fed. Reg. 36,654 (June 5, 2023) (Rule). EPA promulgated the Rule after it concluded that over twenty States had not satisfied the Clean Air Act's requirements, referred to as "Interstate Transport" or "Good Neighbor" requirements. For those states, the Rule imposes emissions limits on certain industrial sources, also referred to as non-electric generating unit (non-EGU) sources (i.e., non-power plant sources). Engines over 1,000 horsepower that are used for pipeline transportation of natural gas are included in the non-EGU source categories covered by the Rule (pipeline engines). The Rule would require compliance for

pipeline engines beginning May 1, 2026, which is a mere 31 months from the effective date of the Rule. Kinder Morgan's goal in commenting on the proposed Rule and filing a motion for stay has never been to avoid regulation altogether; rather, Kinder Morgan merely holds a sensible expectation of reasonable regulation. Kinder Morgan remains committed to implementing a reasonable and cost-effective solution to reduce ozone-precursor emissions.

5. As discussed in more detail below, the Rule, if not stayed by the Court, will cause immediate and irreparable harm to Kinder Morgan and the public. For Kinder Morgan, 591[1] pipeline engines are subject to the nitrogen oxides emissions thresholds in the Rule. Somewhere between 360 and 443 of those pipeline engines will require retrofit, depending on whether EPA determines, in its sole discretion, that any individual facility (and the associated pipeline engines) qualifies for facility-wide averaging, discussed in further detail herein.[2]

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[1] In its comment letter on the proposed rule, Kinder Morgan estimated that approximately 950 of its engines would be subject to the rule. Kinder Morgan estimates that 591 pipeline engines are subject to the Rule. The difference in the values is primarily due to EPA excluding the gathering and boosting segment of the oil and gas industry from the Rule, and the fact that EPA exempted emergency engines.

[2] In addition to the discretionary nature of facility-wide averaging, EPA's methodology requires an evaluation of averaging of pipeline engine emissions data on a rolling basis, based on the prior two ozone seasons. This is problematic insofar as the run time of individual pipeline engines at a facility will vary from year-to-year. Thus, depending on the year a pipeline engine may require controls based on averaging, and then the next year, a different pipeline engine may require controls.

6. The tremendous effort that would be required to retrofit this unprecedented number of existing engines on an incredibly tight timeline will inevitably cause significant service disruptions, including electrical power outages to consumers and industrial customers, home heating outages, and delays to industry supply chains, which pose significant harm to the public interest. The cost to comply with the Rule is **approximately $1.8 to $2.1 billion** for pipeline engines operated by Kinder Morgan (which are all either fully or partially owned by Kinder Morgan). Kinder Morgan is anticipating spending <u>$80 million</u> over the course of the next 12 to 18 months, assuming that the FIP remains stayed in eight states as a result of pending litigation and/or EPA's Interim Final Rule.[3] If the stays of the FIP were lifted across those states, Kinder Morgan anticipates it would be required to incur an *additional* <u>$190 million</u> in the next 12 to 18 months.[4] In the Interim Final Rule in

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Over the course of the next five to ten years, Kinder Morgan's analysis indicates that nearly every individual engine is likely to require controls, which makes the financial (or cost-effective) benefit of facility-wide averaging largely obsolete. To address this issue, Kinder Morgan considered facility-wide averaging assuming its pipeline engines will operate 24 hours a day, 7 days a week, 365 days a year. This approach is different than EPA's formula in the Rule, which states an operator should use the highest consecutive 30-day operating period during the ozone season from the past two years for each pipeline engine.

3 EPA, *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States*, released July 6, 2023, unpublished, EPA-HQ-OAR-2021-0668; FRL-8670.2-03-OAR (Interim Final Rule).

4 This cost estimates the retrofits that Kinder Morgan expects available vendors can reasonably achieve in the next 12 to 18 months.

particular, EPA did not expressly stay the effective date of the Rule for pipeline engines. Kinder Morgan and other industry cannot rely on EPA's uncertain regulatory action.[5]

7. Importantly, for nearly 75 percent of Kinder Morgan's engines (329 of 443) that will require retrofit, the cost-per-ton to install the required emissions control technologies will exceed $7,500, which is the cost-effectiveness threshold that EPA stated it used to initially select which emissions controls and thresholds to mandate in its Proposed FIP.[6] In some cases, Kinder Morgan's costs-per-ton are in excess of $100,000 for an individual pipeline engine, and Kinder Morgan estimates that more than 216 (of 443) pipeline engines would cost more than $20,000 per ton of nitrogen oxides emissions reduced.[7]

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[5] Interim Final Rule, at 12 ("At the time of this rulemaking, the EPA cannot predict how the Agency's future action may affect the amendments being finalized in this action.")

[6] In arriving at estimated cost-per-ton thresholds, Kinder Morgan evaluated costs compared to a five-year average of the operating hours of the individual engine to balance out any potential high or low years. This is more conservative than EPA's approach which used "actual emissions from the 2019 emissions inventory." 88 Fed. Reg. at 36,733. Kinder Morgan notes, however, that the cost-per-ton analysis it conducted to arrive at the pipeline engine count in this Paragraph 7 does not include the "reservation charge credit" refunds that Kinder Morgan will be required to pay its customers for failure to provide contracted capacity. *See infra* ¶¶ 70–72.

[7] In arriving at estimated cost-per-ton thresholds, Kinder Morgan evaluated costs compared to a five-year average of the operating hours of the individual engine to balance out any potential high or low years.

8. EPA's facility-wide averaging concept will not reduce the installation costs to the EPA's stated cost-effectiveness threshold. Kinder Morgan's 443 pipeline engines are located across 63 facilities. Applying EPA's facility-wide averaging concept, and considering costs, Kinder Morgan could only apply facility-wide averaging at 29 facilities. Facility-wide averaging would only eliminate 83 engines from requiring retrofit, which is less than 20 percent of Kinder Morgan's engines that require control. Averaging also does not materially reduce costs because, in many cases, it would cost Kinder Morgan more to over-control several engines at a facility, rather than controlling each individual engine to the emissions threshold. Thus, on a per-pipeline engine basis, it will cost more to apply facility-wide averaging than it will to control each individual pipeline engine. Analysis indicates that facility-wide averaging offers no meaningful reductions in costs or the number of pipeline engines requiring retrofits to comply with the Rule. At any rate, costs committed to compliance cannot be recovered if this Court determines that the Rule is unlawful, as Kinder Morgan contends the Court should.

9. Compounding these astronomical costs is the Rule's unreasonable timetable for compliance. EPA states that industry must start now to meet the compliance deadline: The Rule directs "source owners and operators that they should begin engineering and financial planning . . . to be prepared to meet this implementation timetable." 88 Fed. Reg. at 36,755. As outlined in this declaration,

even if Kinder Morgan begins planning, design, and other pre-installation work immediately to attempt to meet EPA's emission limits by the compliance deadline of May 1, 2026, Kinder Morgan will not achieve compliance in less than three years.

10. Considering its real-world experience and depending on whether and to what extent Kinder Morgan could meaningfully apply facility-wide averaging, Kinder Morgan's analysis suggests a realistic completion date of no earlier than March 2029 as the best-case scenario, and December 2030 as the more likely scenario. Both dates are well beyond May 1, 2026. As a result, the Rule would require over 50 percent of Kinder Morgan's pipeline engines be granted a timeline extension, and some retrofits could extend beyond the discretionary timeline extensions the EPA suggests it would *consider*.

11. Regardless of the timetable, compliance will result in significant interruptions of service to the public. For example, one computer simulation modeling exercise shows that if Kinder Morgan sought to achieve full compliance on one pipeline segment by May 1, 2026, it would fail to fulfill hundreds of thousands of dekatherms/day of natural gas capacity, which equates to a failure to provide natural gas to millions of homes for heat and cooking, and hot water for bathing. These modeling exercises provide only one snapshot of a single Kinder Morgan pipeline segment. These service interruption impacts would be

compounding across Kinder Morgan pipelines, as well as the national natural gas pipeline transportation sector.

12. The failure to provide continuous service will also cause Kinder Morgan to violate its obligations to the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act. Breaks in continuous service require Kinder Morgan to refund charges to natural gas shippers, resulting in additional significant charges and costs that EPA did not consider, up to tens of millions of dollars *per individual pipeline segment*. Indeed in the example discussed below, the charges were estimated at $120 million for only three segments.

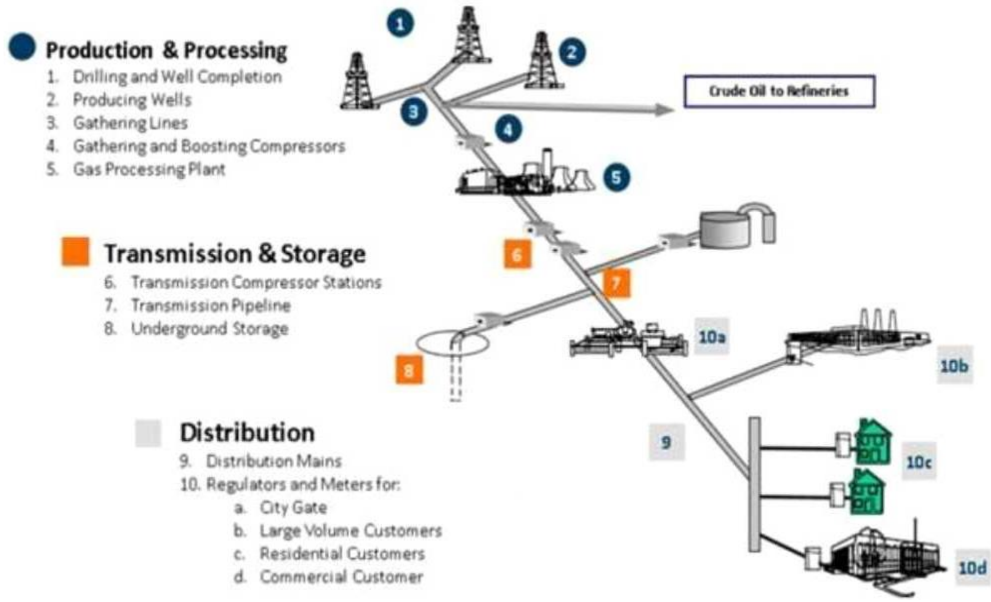
13. Thus, absent a stay, Kinder Morgan will be irreparably harmed.

Kinder Morgan is an Indispensable Player in the Natural Gas Supply Chain.

14. The natural gas industry involves three basic sectors: production and processing; transmission and storage; and distribution to consumers. Once extracted from the ground, oil and natural gas are transported to processing plants and processed into pipeline-quality natural gas. From there, natural gas transmission pipelines (either intrastate or interstate) move the natural gas to large industrial and commercial customers (such as power companies) and local distribution companies. Local distribution companies then deliver gas to retail consumers like homes and businesses to use for heating, cooking, fueling hot water heaters and other necessities.

15. Natural gas transmission pipelines and storage are indispensable steps in the natural gas supply chain. These pipelines form a vast cross-country highway of sorts, connecting sources of natural gas to the ultimate consumers. Natural gas is used to generate electricity for residential, commercial, and industrial applications; to heat and cool our homes; to cook food for our families; to fuel hot water heaters for bathing and to serve other necessary functions that support a basic standard of living. Underground storage of natural gas is similarly critical to the supply chain. As the term implies, underground storage of natural gas involves storing natural gas in underground formations. Storage capacity ensures that sufficient natural gas is available regardless of seasonal ebbs and flows of natural gas production or consumption. It makes gas reliably available to consistently serve basic human needs every hour of every day of every year, including at peak times during the coldest winter nights (for heating) and the hottest summer days (for electric power generation for air conditioning). Figure 1, below, shows how natural gas transmission and storage play a critical role in the natural gas supply chain:

Figure 1: The Natural Gas Supply Chain



Source: Adapted from the American Gas Association and EPA Natural Gas STAR Program.

16. Kinder Morgan has interests in approximately 62,000 miles of natural gas transmission pipelines and owns approximately 700 billion cubic feet of underground storage capacity for natural gas. Kinder Morgan operates within 44 states and has natural gas transmission facilities in 32 states. Kinder Morgan's natural gas transmission pipelines are connected to every important natural gas resource in the lower 48 states, including the Bakken, Eagle Ford, Marcellus, Permian, Utica, Uinta, Haynesville, Fayetteville, Barnett, Mississippi Lime, and Woodford. Kinder Morgan's transportation of natural gas plays a significant role in meeting both the nation's long-term natural gas supply needs as well as its emission-reduction goals, particularly supporting the electricity sector's transition away from coal-fired power plants.

17. Approximately 40 percent of the natural gas consumed in the United States is transported by pipelines owned or operated by Kinder Morgan companies. Key Kinder Morgan natural gas pipeline assets include Natural Gas Pipeline Company of America LLC (which serves the high-demand Chicago market); Tennessee Gas Pipeline (which serves the supply-restricted areas in the Northeast including New York City and Boston as well as the Gulf Coast); Southern Natural Gas (which serves the southeastern United States); intrastate pipelines in Texas (the largest producer and consumer of natural gas in the United States); and El Paso Natural Gas Pipeline and Mojave Pipeline (which serve the southwestern United States, including supply-restricted California markets).

18. Natural gas-fired reciprocating internal combustion engines (i.e., pipeline engines) make it possible for companies like Kinder Morgan to serve these energy markets and provide natural gas for public use. These engines are used at compressor stations along Kinder Morgan's natural gas transmission pipelines to compress the natural gas that Kinder Morgan transports. Compressing the natural gas increases its pressure, enabling the gas to flow along the pipeline system. Compressor stations are typically spaced about 40 to 100 miles apart, depending on topography, pipeline routes, pipeline diameter, and other factors. Natural gas is re-compressed at each station to facilitate its movement to the next station, ultimately arriving at (1) the facilities of industrial consumers including power generation, (2)

underground storage facilities for storage until demand increases (like during winter months), or (3) local distribution companies for distribution to residential, commercial, and other industrial consumers.

19. Although pipeline engines are "engines," these are not the typical engines found in cars. Pipeline engines are very expensive and very large. They weigh at least 100,000 pounds (50 tons) and as much as 365,000 pounds (182.5 tons). To put that weight in perspective, an average pickup truck weighs approximately 5,000 pounds. This means a large pipeline engine weighs the same as approximately 73 pickup trucks. The price of a new pipeline engine typically ranges from about $300,000 (for engines with less than 1,000 horsepower—five times greater than the horsepower of a standard car) to as much as $7 million (for engines larger than 5,000 horsepower).

20. Protecting public health, safety, welfare, and the environment has always been a priority for Kinder Morgan. Further, per the Company's commitment to sustainable operations, Kinder Morgan is a founding member of ONE Future, a unique coalition made up of members across the natural gas industry focused on identifying policy and technical solutions to improve the management of emissions associated with the production, gathering, processing, transmission, and distribution of natural gas. Members of ONE Future are committed to continuously improving their emissions management to achieve voluntary reductions in emissions and to

assure efficient increased use of natural gas. In connection with Kinder Morgan's membership in ONE Future, the Company joined EPA's Methane Challenge program in 2016. As part of this program, Kinder Morgan committed to achieving a methane emission intensity target of 0.31 percent by 2025. In 2022, Kinder Morgan achieved an emissions intensity of 0.03 percent. Surpassing the 0.31 percent intensity target by such a wide margin reflects Kinder Morgan's deep commitment to reducing emissions from its operations. From 2020 to 2022, Kinder Morgan also achieved voluntary reductions in carbon dioxide equivalent emissions of 10.3 million metric tons and voluntary reductions in methane emissions of 19.1 billion cubic feet, resulting in an estimated $104 million in natural gas saved.

The Rule Applies to Many of Kinder Morgan's Engines.

21. For the first time, the Rule establishes nitrogen oxide emission limits for the natural gas industry's use of reciprocating internal combustion engines in pipeline transportation. The Rule imposes stringent regulations on engines of 1,000 horsepower and greater located in the States EPA says did not satisfy the Clean Air Act's requirements. In particular, under the Rule, "two stroke lean burn" engines must achieve an emissions rate limit of 3.0 grams per horsepower per hour (g/hp-hr), "four stroke lean burn" engines must achieve an emissions rate limit of 1.5 g/hp-hr, and "four stroke rich burn" engines must achieve an emissions rate limit of 1.0 g/hp-hr. By way of comparison and to provide context, in the Rule, EPA assumes

the uncontrolled industry average emissions rate for a two stroke lean burn engine is 16 g/hp-hr, over five times higher than the emissions threshold required in the Rule. For additional context, the Rule is targeting ozone-precursor emissions to address the maintenance and attainment of the 2015 *Ozone* National Ambient Air Quality Standard. Specifically, this Rule targets nitrogen oxides, as an ozone-precursor. Importantly, nitrogen oxides are not greenhouse gas emissions, and therefore, a reduction in nitrogen oxides does not reduce local, regional, national or global greenhouse gas emissions.

22. The stringent emissions limits in the Rule can be satisfied only by implementing controls on reciprocating internal combustion engines. "Controls" describe a range of aftermarket technological modifications to engines to limit their emissions. The technical and cost practicability of installing controls on any individual engine depends on site-specific considerations such as space for the installation of the control, the availability of sufficient power, the make, model and age of the engine, and, of course, the emissions reductions required to meet the Rule's requirements. Costs are largely driven by the fact that control technologies are limited, and where they are feasible, it is no small task to address aftermarket retrofit technologies on these engines.

23. These strict new limits under the Rule apply to approximately 591 of Kinder Morgan's engines, which are located across 90 transmission compressor

stations. Of those 591 engines, nearly 75 percent (about 443 engines) operate above the emissions thresholds in the Rule.[8] Those 443 engines are located across 63 compressor stations. Many of these engines operate close to the emissions thresholds, but would require additional, incremental controls. Notably, 469 of Kinder Morgan's 591 pipeline engine are two stroke lean burn engines, which limits control technologies. Considering cost-effectiveness of the control technologies, Kinder Morgan could only apply facility-wide averaging at 29 of 63 compressor stations. This would exempt only 83 of 443 engines (less than 20 percent) from requiring controls under the Rule, leaving Kinder Morgan at least 360 engines to retrofit by May 1, 2026.

24. Kinder Morgan offered extensive comments on EPA's proposed rule, including detailed exhibits. Kinder Morgan specifically raised concerns regarding EPA's underlying data (in particular with respect to pipeline engine count and estimated actual emissions), technical feasibility analyses, cost and cost-effectiveness calculations, and unreasonable timelines, among other concerns. Kinder Morgan also offered an alternate proposal for EPA and states to comply with the Clean Air Act, suggesting EPA promulgate a model rule (as it has done in the

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[8] While 591 of Kinder Morgan's engines are subject to the Rule (i.e., are larger than 1,000 horsepower), 128 of those engines currently operate below the emissions thresholds in the Rule. Kinder Morgan's efforts to install controls on these 128 engines across the Unites States has taken place over the course of multiple decades.

past) that each state would adopt, which would both allow emissions averaging at company-wide level within a state, and strictly consider cost-effectiveness and technical feasibility thresholds. Kinder Morgan welcomed the opportunity to engage and dialogue with EPA to identify a reasoned solution. In the interim, Kinder Morgan respectfully requested EPA re-publish a revised proposal and incorporate Kinder Morgan's workable state-wide, company-wide averaging program, coupled with a cost-effectiveness threshold.

The Rule Imposes Enormous Costs of Compliance on Kinder Morgan.

25. The installation of controls at all required engines would require an immense and unprecedented effort on behalf of Kinder Morgan and its contractors. Kinder Morgan has experience installing control equipment at its units, but not on the scale and magnitude as required by the Rule, and certainly not within the mandated timeline of less than three years. Kinder Morgan has already begun extensive planning to comply with the Rule, which requires Kinder Morgan to make immediate expenditures.

26. Installing the necessary controls to achieve the Rule's required emissions limits will be astronomically expensive, even by EPA's own optimistic estimates. Even incorrectly assuming an average cost-per-ton of $4,981 for pipeline engines, EPA anticipates that operators will be required to spend approximately $425,000 per engine in the year 2026 on installing the required controls. 88 Fed.

Reg. at 36,739. Using EPA's incorrect data, for Kinder Morgan's 443 engines alone, EPA's estimate amounts to Kinder Morgan spending more than $188 million. However, using actual and current cost data, Kinder Morgan will spend between **$1.8 and $2.1 billion to comply with the Rule**, which amounts to approximately **$4.74 million (no facility-wide averaging) to $5 million (facility-wide averaging) per pipeline engine**. Interestingly, the overall cost-per-engine would be higher if Kinder Morgan elects to apply facility-wide averaging. This is largely because it will cost Kinder Morgan more per pipeline engine to overcontrol an engine, as opposed to controlling all engines from the start. This result is contrary to EPA's suggestion that Kinder Morgan's costs will decrease dramatically by applying facility-wide averaging.

27. EPA's cost estimates are wrong because EPA relies on extremely outdated cost data, which is far lower than actual costs Kinder Morgan experiences for available control technology. Even though EPA expressly recognized that the control technologies it selected will not be cost-effective considering the variation of costs associated with different types of technologies and as applied to different types and vintages of engines, the agency nonetheless proceeded with the identified control technologies and associated emissions reductions.

28. Kinder Morgan has calculated that its costs would be between $1.8 billion and $2.1 billion to install required controls for all of its affected engines to

satisfy the applicable emissions rate limits under the Rule. In the next 12 to 18 months, Kinder Morgan will be required to spend nearly **$80 million** to attempt to comply with the Rule, or **$270 million** if the individual state stays (put in place by other Circuit Courts) are lifted, with no ability to recover the costs from the government. These costs will include but are not limited to the cost of contracting for labor, parts, engineering, planning, permitting, and other capital costs.

29. Importantly, for 329 (of 443) engines, the costs to achieve the emissions threshold will exceed the $7,500 per ton cost-effectiveness threshold that EPA relied on in its Proposed FIP to determine reasonable control technologies for this segment of industry. Kinder Morgan offered extensive comments during the comment period, producing detailed and site-specific studies of pipeline engines operated by Kinder Morgan, analyzing and demonstrating that the cost-per-ton of nitrogen oxide reduced can be in excess of $600,000 in some circumstances. For this declaration, Kinder Morgan provides a couple of examples of the costs-per-ton estimates (evaluated as of 2022) required to control engines subject to the Rule in the following two paragraphs. Each of these examples were provided to EPA during the comment period.

30. Kinder Morgan evaluated the costs of adding selective catalytic reduction to a type of two stroke lean burn engine built by Worthington. Kinder Morgan estimates capital costs of $6,215,151 to install a control technology referred

to as selective catalytic reduction (SCR). The largest component of this cost ($3,138,700) is for the construction contractor (both the primary and secondary), and the second-largest component ($1,326,500) is for the control technology materials. This estimate is dated September 8, 2021, meaning that the inflationary and market (i.e., high-demand) environment has driven these costs up even higher. Further, the resulting cost-per-ton of nitrogen oxide reduced by adding SCR at this engine would be approximately $19,158 per ton, which is far higher than EPA's initial estimates of no more than $7,500 per ton.

31. In its cost analyses, EPA assumed SCR is the preferred, or most used, technology. That is not the case for Kinder Morgan. SCR is an add-on control system that removes nitrogen oxides from a turbine's exhaust gas by causing a chemical reaction between nitrogen oxides and ammonia gas. The ammonia gas is added prior to the exhaust reaching the SCR catalyst, and the chemical reaction occurs as the exhaust passes through the catalyst chamber. The process requires a significant amount of ammonia in quantities that are regulated by the Occupational Safety and Health Standards, Process Safety Management regulations for hazardous chemicals. Further, even without these other environmental and regulatory challenges, SCR does not function unless the exhaust temperature is sufficiently high. Many of Kinder Morgan's two stroke lean burn engines do not operate at high enough

temperatures to allow for effective control and therefore SCR is not a universally viable option.

32. Kinder Morgan also evaluated the costs for a four stroke lean burn engine manufactured by Ingersoll-Rand (model: KVG-310) to meet the Rule's 1.0 g/hp-hr limit. The project would require non-selective catalytic reduction, air-fuel ration controllers, and adding turbochargers to meet the 1.0 g/hp-hr limit, resulting in a total project cost of $5,684,158. Based on the level of emissions reductions achieved, the resulting cost-per-ton of nitrogen oxide reduced would be $684,169, which greatly exceeds EPA's estimates. This estimate reflects the likely costs for all three of Kinder Morgan's four stroke lean burn Ingersoll-Rand Engines.

Case-by-Case Emissions Exemptions and the Facility-Wide Emissions Averaging Concepts Do Not Meaningful Reduce the Enormous Costs of Compliance on Kinder Morgan.

33. Recognizing the cost challenges in the pipeline transportation sector, EPA purports to provide relief through two options: case-by-case exemptions and facility-wide averaging. Neither option provides the requisite relief. And, beyond the substance, when more engines will go through the exception process than the Rule itself, it proves how illogical the Rule is.

34. The Rule includes a provision for case-by-case exemptions that would allow EPA to approve, at the agency's sole discretion, unit-specific emissions rates. This provision does not eliminate the enormous costs imposed on Kinder Morgan.

Kinder Morgan anticipates that it will need to submit case-by-case requests for at least 250 engines. EPA requires a showing of "extreme economic hardship" to approve a request for a unit-specific emission rate, a term that EPA has not defined (either in narrative or with a cost-per-ton value), and Kinder Morgan has no way to assess what the exemption means. EPA is also requiring all case-by-case requests be submitted to EPA no later than August 5, 2024 (one year after the effective date of the Rule). Each exemption request requires expansive technical, emissions profiling, and cost analysis that are no simple feat. Neither Kinder Morgan nor EPA have processed exemptions on this scale, and EPA has also not offered any anticipated timeline by which applications for individual unit-specific exemptions would be processed. Kinder Morgan cannot rely on a remote, and completely discretionary, chance of relief on only certain, individual engines. To attempt compliance with the Rule, Kinder Morgan must begin implementing engine controls on all of its pipeline engines now, at great expense.

35. EPA also suggests that the Rule has built-in compliance flexibility to mitigate any costs concerns by way of the EPA's facility-wide averaging proposal. EPA's facility-wide averaging program would allow an operator to take a facility-wide emissions "cap," which would be equal to the total nitrogen oxide emissions allowed for that facility based on the pipeline engine-specific emissions thresholds. In other words, if the average emissions from all the subject pipeline engines at the

facility equal the average emissions thresholds for those pipeline engines under the Rule, then the facility (and all engines) are in compliance. In theory, this provision allows an operator to "over control" some engines to achieve lower emissions than those required by the Rule, and in exchange, other pipeline engines would not require any modification or control.

36. As a threshold matter, the formula codified in the Rule has an error. If applied strictly as drafted, the equation gives an operator a cap it could most likely never exceed and it would most likely not be required to control any units on the site. The error is that the conversion factor from grams per day to tons per day is improperly applied. These values calculated as codified leaves both the facility-wide average cap and facility-wide average actual emissions in grams per day, not tons per day, with the facility wide average cap multiplied by an additional factor of 907,184.74. I expect this was not EPA's intent. This further undermines EPA's facility-wide averaging approach. For purposes of this declaration, however, Kinder Morgan applied the formula, correcting the equation error.

37. If applied as corrected, facility-wide averaging would have an operator determine the highest consecutive 30-day operating period during the ozone season from the past two years for each engine. The operator would then calculate the average daily operating hours for each engine, and multiply those hours by the unit's design horsepower and the applicable rule limit (i.e., g/hp-hr). The operator would

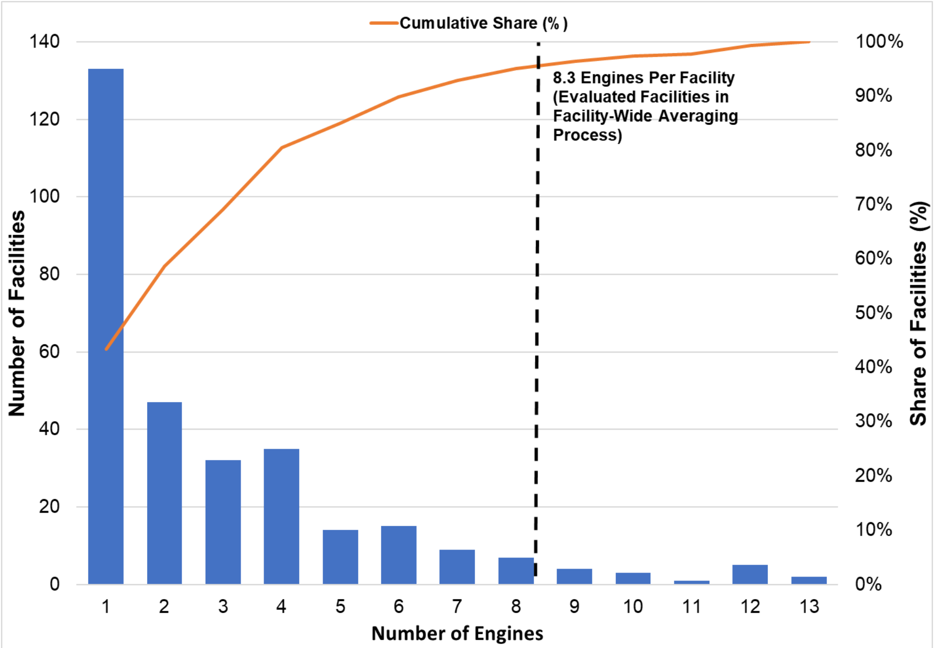
then convert to tons per day for each engine and sum the resultant values to get a facility-wide cap in tons per day of nitrogen oxides. Using facility-wide averaging, theoretically, the facility has the flexibility to apply controls on one or more engines at its facility to meet this facility-wide cap. As explained below, this concept does not work in practice.

38. EPA extrapolated this theory to its data set of 3,005 pipeline engines subject to the Rule. By its calculation, EPA determined that averaging would only require controls on one-third of all engines in the transmission pipeline sector that are subject to the Rule. If accurate, this would mean that of the 3,005 engines subject to the rule, EPA believes only 905 would require controls. The problem is the very small, and unrepresentative data set EPA used to justify facility-averaging. Specifically, EPA relied on a sample set of ten facilities (a total of 43 pipeline engines) from a total of 713 facilities (and 3,005 pipeline engines). EPA's ten selected facilities average 8.3 engines per facility. As discussed below, that is not representative of the facilities subject to the Rule. Of the 43 engines that EPA deemed to be controlled in the facility-wide averaging plan, only 34 of these engines appear in EPA's 905-engine subset, while the rest of the 9 engines do not (and thus are assumed not subject to emissions thresholds under Rule). EPA also did not consider pipeline engines located at any facility in Louisiana, the state with the highest number of covered pipeline engines under the Rule. Further, the ten facilities

that EPA evaluated are located in 6 states, which constitutes less than half of the 20 states subject to pipeline engines requirements under the Rule. This is a consequence of selecting sample facilities to use in the facility-wide averaging approach that are biased, non-representative, and represent only a very small sample of the engines in the 905-engine subset. The bottom line is that the sample set that EPA used to extrapolate in support of the entire Rule is not representative of the number of facilities at each compressor station, the technology types, engine design capacity, and annual nitrogen oxide emissions. Furthermore, EPA did not provide documentation on the process that EPA followed while selecting the ten sample facilities.

39. Figure 2 below shows the distribution of the 905 engines across all 307 facilities subject to the Rule. This distribution reflects that 133 facilities (out of the 307 total facilities, or 43% of the facilities) have only one engine, approximately 58% of the 307 facilities have two or fewer engines, and approximately 90% of the 307 facilities have 6 or fewer engines. By comparison, EPA's ten sample facilities average 8.3 engines per facility, and none of them contain only one engine. This skews EPA's averaging results.

Figure 2: The Distribution of Engines Across Facilities Subject to the Rule, Compared to EPA's Sample Set



Sources: Non-EGU Facilities and Units.xlsx; Pipeline Natural Gas - Engine Analysis data

40. Notably, two of Kinder Morgan's compressor stations were included in the very small sample set of the ten facilities EPA analyzed, and Kinder Morgan can show with precision how EPA's facility-wide averaging analysis does not work. These facilities are Tennessee Gas Pipeline Station 214 and Tennessee Gas Pipeline Station 209.

41. At Tennessee Gas Pipeline Station 209 (a facility owned and operated by Kinder Morgan), EPA assumed that only 9 of 13 pipeline engines would require controls based on facility-wide averaging. Considering the averaging data only, and

disregarding costs, Kinder Morgan's actual emissions data demonstrates that Kinder Morgan would have to over-control 10 of the 13 pipeline engines to make the facility-wide averaging work. However, neither EPA's emissions averaging calculation (9 engines requiring control) nor Kinder Morgan's (10 engines requiring control) considers cost-effectiveness. Considering costs, it would be more cost-effective for Kinder Morgan to retrofit *all* 13 pipeline engines than it would be for Kinder Morgan to overcontrol 10 pipeline engines. Therefore, the Station 209 example does not support an overall two-thirds cost savings across Rule applicability using facility-wide averaging.

42. Tennessee Gas Pipeline Station 214 (owned and operated by Kinder Morgan) has a similar result. This facility operates 13 pipeline engines. EPA applied facility-wide averaging and calculated that only 4 of the 13 engines would require controls. This is however, a faulty and non-representative sample. EPA fails to clarify that the remaining 9 engines that EPA says do not require controls are already controlled and operating below the emissions thresholds in the Rule. So realistically, facility-wide averaging at this facility just means every engine onsite requires controls.

43. This type of discrepancy between EPA's assumptions and reality is rife across Kinder Morgan's fleet. Considering facility-wide averaging on a cost-effective basis, Kinder Morgan's analysis shows it could only apply facility-wide

averaging at 29 of 63 compressor stations, which would eliminate only 83 (of 443) engines from requiring retrofit under the Rule. This is only a 19 percent reduction in engines requiring controls, not the sweeping 67 percent that EPA suggests.

44. Further compounding the issue, EPA's averaging analysis is based on a moving target. The averaging analysis must consider data on a 30-day rolling emissions average, based on the prior two ozone seasons. Each pipeline engine operates a different number of hours every year. Importantly, the number of hours a pipeline engine runs per year is primarily a function of customer demand for natural gas, which of course varies over time. Kinder Morgan's analysis indicates that because of the "rolling" data that informs averaging, over the course of the next five to ten years, nearly every individual engine is likely to require controls, which makes any financial benefits of facility-wide averaging obsolete.

The Direct Costs Kinder Morgan Would be Required to Incur to Comply with the Rule Will Restrict Other Planned Business Opportunities.

45. Furthermore, the costs Kinder Morgan must divert to comply with the Rule will leave Kinder Morgan unable to pursue other planned business opportunities. Kinder Morgan's long range outlook plans include a variety of business opportunities, including those focused on efficient, greenhouse gas reducing projects. In the future, if Kinder Morgan is capital constrained as a result of the Rule, Kinder Morgan may be unable to pursue similar projects, for example, to build natural gas pipeline facilities to support the retirement of third-party coal-

fired generating units for replacement with lower carbon power generation (i.e., natural gas). For instance, the energy market often releases requests for proposals for diversified, reliable, and low-cost energy. Kinder Morgan plays an important role in these environmentally responsible and reliable power projects because natural gas is needed to support innovative projects. The following are examples of new-energy projects that Kinder Morgan typically supports: the Kentucky Municipal Energy Agency[9] (soliciting innovative energy proposals, including for natural gas combustion turbines), the Electric Reliability Council of Texas (soliciting qualified loads and generators to make themselves available for deployment in an electric grid emergency),[10] Integrated Resource Plans from Dominion Energy South Carolina, Inc. (evaluating resource adequacy, reliability, and commodity pricing and

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[9] Kentucky Municipal Energy Agency, Request for Proposals, *available at* https://www.kymea.org/rfp/ (last visited July 13, 2023).

[10] Electric Reliability Council of Texas, Inc., Emergency Response Service, *available at* https://www.ercot.com/services/programs/load/eils ("ERS decreases the likelihood of system-wide load shedding by paying qualified scheduling entities (QSE) to make arrangements with residential, commercial and industrial participants to either reduce consumption or increase generation across the grid when called upon by ERCOT. These participants are required to provide an agreed-upon amount of megawatts (MW) within ten to thirty minutes to help prevent or alleviate an actual or anticipated Energy Emergency Alert (EEA) event."); *see also* Electric Reliability Council of Texas, Inc., Emergency Response Service Request for Proposal (Jan. 31, 2023), *available at* https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.ercot.com%2Ffiles%2Fdocs%2F2023%2F01%2F31%2FRequest-for-Proposal-ERS-AprMay23.docx&wdOrigin=BROWSELINK.

developing a strategic framework),[11] and Tennessee Valley Authority 2019 Integrated Resource Plan (evaluating resource adequacy and reliability as the TVA power system is required to be self-supporting and operated on a nonprofit basis, at lowest cost rates, as feasible).[12]

46. The costs required for compliance with the Rule will also divert resources from Kinder Morgan's efforts to modernize facilities, ensure pipeline integrity above and beyond the regulatory requirements, and achieve voluntary additional emissions reductions (*see supra* ¶ 20). For example, in 2023, Kinder Morgan spent approximately $54 million in voluntary operations and maintenance practices and approximately $49 million in voluntary capital projects, both focused on pipeline integrity. Through these voluntary programs, for example, Kinder Morgan conducted additional inline inspections of pipelines beyond what was required by the Pipeline and Hazardous Materials Safety Administration, the

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[11] Dominion Energy South Carolina, Inc., 2023 Integrated Resource Plan *available at* https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integrated-resource-plan.pdf (Filed January 30, 2023) ("Although most of the resources added in all build plans are non-emitting resources, the modeling shows that natural gas generation is also needed to support reliability and supply low-cost energy.").

[12] Tennessee Valley Authority, 2019 Integrated Resource Plan, Volume I – Final Resource Plan (2019), *available at* https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4 ("Gas, storage and demand response additions provide reliability and/or flexibility across all seasons").

purpose of which was to inspect for potential anomalies that require additional investigation and likely remediation to maintain safe operation of the pipelines. The costs of compliance with the Rule will curtail Kinder Morgan from engaging in similar projects planned in the next several years.

47. Thus, absent a stay, Kinder Morgan will be required to expend resources, not recoverable from the government, at a level contrary to EPA's own cost-effectiveness thresholds and averaging evaluations.

The Rule's Accelerated Timeline for Compliance Compounds the Costs to Kinder Morgan.

48. The Rule's compliance deadline of May 1, 2026, to implement all the mandated controls is unreasonable and impossible. Kinder Morgan operates 443 engines that do not currently meet the emissions thresholds. Based on Kinder Morgan's significant real-world experience of deploying emissions reduction technologies on large engines, Kinder Morgan estimates that a realistic completion date is no earlier than March 2029, and December 2030 as the more likely scenario. Both dates are well beyond May 1, 2026. As a result, the Rule would require over 50 percent of Kinder Morgan's pipeline engines be granted a timeline extension, and some retrofits could extend even beyond the discretionary timeline extensions the EPA considered.

49. Transmission pipeline engines are large, complex pieces of equipment, and retrofitting engines with emissions controls involves a multi-step process with

long lead times to appropriately stagger control deployment in a manner that ensures continuity of service; engine-specific design, engineering, and procurement of equipment; and contracting with specialized contractors to install and test equipment given the complexity of reciprocating internal combustion engines.

50. As noted above, nearly 80 percent of Kinder Morgan's pipeline engines are two stroke lean burn engines. There are only two vendors nationwide with the necessary equipment and experience in retrofitting Kinder Morgan's two stroke lean burn engines. These vendors have never processed the scale and magnitude of requests that the Rule forces. Indeed, one of Kinder Morgan's primary contractors has shared that over the last 25 years, it has modified approximately 400 total engines across all of the pipeline transportation industry. This rate of approximately 16 engines a year would not allow Kinder Morgan, let alone the entire pipeline transportation sector, to achieve compliance by May 1, 2026.

51. Even the study EPA published in support of the proposed timetable identified lack of skilled labor as a concern. The report says the compliance timeline is possible because the skilled labor pool "should be present," or "has likely already grown." EPA Timing Report at 60. No further data was provided to demonstrate this is the case. Kinder Morgan and consumers of natural gas cannot rely on the unpredictable status of the manufacturer's timetable and unsupported prognoses on

the skilled labor force, the latter of which realistically needs to be in place in the next few months in order to even attempt to comply with the Rule.

52. In addition, Kinder Morgan faces other hurdles that impact its compliance timeline. Nearly all emissions control projects require permits or permit modifications from EPA or state agencies before an operator is allowed to start construction to physically modify an engine. EPA estimated permitting timeframes range from 6–12 months. In my experience at Kinder Morgan, while minor modifications for permits often take around 90 days, major permit modifications, or new permits, can take 24 months or more to process. These permit applications require significant time from both external consultants and Kinder Morgan staff to complete, often between 65 and 500 total hours to prepare an individual application. For example, as recently as 2021, Kinder Morgan submitted an application for a permit modification to a major source permit to the Louisiana Department of Environmental Quality. The application was of the type that would be required before Kinder Morgan could undertake pipeline engine modifications required by the Rule. That project required 200 hours of consultant and Kinder Morgan staff time to prepare the application and coordinate with the regulatory agency. From start to finish, inclusive of application preparation time, agency processing time, and public comment, permitting for this application took 14 months. This is just one of

many real-world examples of realistic permitting timelines caused by factors outside of Kinder Morgan's control, including understaffed state agencies.

53. Nearly all of Kinder Morgan's facilities where the pipeline engines are located are major sources. This means that if there is any substantial incremental increase in any regulated pollutant, the entire facility (and not just an individual emissions source) will trigger Prevention of Significant Deterioration permitting, which is one of the most complex and lengthy permitting processes required by the Clean Air Act, well beyond even EPA's longer permitting timelines.

54. Recognizing that its own compliance timeline is incredibly short, EPA attempts to take cover by claiming that publication of the proposed rule "provided roughly an additional year of notice" that operators should begin implementation. 88 Fed. Reg. at 36,755. It would have been entirely irresponsible for Kinder Morgan to expend capital and material costs on a draft proposed rule that is subject to change, and in particular, when the proposal is one of the most highly contested rules EPA has published in the recent past, as evidenced by the numerous pending challenges to the Rule.

EPA's Discretionary and Limited Timeline Extensions Do Not Address Kinder Morgan's Concerns.

55. The Rule's provision of compliance deadline extensions on a case-by-case basis does not lessen the concerns on feasibility to comply or costs to comply. As stated above, based on Kinder Morgan's experience, the Rule would require

Kinder Morgan to apply for a discretionary timeline extension for over 50 percent of the pipeline engines in its fleet, and some retrofits could extend even beyond the discretionary timeline extensions to be considered by EPA.

56. Because the timeline extension is discretionary, Kinder Morgan cannot delay its preparations for compliance with the Rule based on an assumption that EPA will grant an exemption. This is particularly true where, in its June 2023 Interim Final Rule, EPA declined to expressly extend the May 1, 2026 deadline for pipeline engines pending judicial review of the Rule. This omission to extend the timeline speaks for itself. And because the Rule says that even to be considered for an exemption, Kinder Morgan must "take[] all steps possible to install controls for compliance with the applicable requirements," Kinder Morgan must take action now to install emissions controls during the time the appeal is pending in this case. 88 Fed. Reg. at 36,760. Further, whether Kinder Morgan will fail to provide continuous service to its customers (thus violating FERC's continuous service requirements) is not listed as a factor EPA will consider in its assessment of whether to grant an operator more time to achieve compliance.

57. Finally, the extension process further restricts the compliance timeline because owner or operator must submit the request to EPA at least 180 days before the May 1, 2026 deadline. 88 Fed. Reg. at 36,760. The owner or operator remains subject to the May 1, 2026 until the compliance deadline is granted, which opens

Kinder Morgan to fines should that extension not be granted in a timely manner. There is no certainty in this completely discretionary path, and Kinder Morgan cannot rely on it. As EPA states, "A denial will be effective on the date of denial." 88 Fed. Reg. at 36,760.

EPA's Compliance Timetable Fails to Meaningfully Consider the Natural Gas Act's Underlying Purpose of Ensuring Continuity of Service.

58. Another critical component of the compliance timeline is ensuring continuity of service consistent with Kinder Morgan's obligation to comply with the Natural Gas Act as implemented by FERC. Protecting continuity of service is a paramount concern for FERC, and natural gas pipelines must remain operational at all times to meet their natural gas delivery obligations. The expedited timeline for the Rule's mandated controls will curtail Kinder Morgan's ability to meet its FERC obligations. It does not appear that EPA considered the central role that the pipeline transportation sector plays in providing natural gas to consumers and to the overall energy generation and electric grid reliability discussion.

59. According to publicly available information, EPA documented only one meeting with FERC in January 2023, well into the rulemaking process. EPA-FERC Meeting on GNP" Presentation, Dkt. No. EPA-HQ-OAR-2021-0668-1175 (Jan. 9, 2023), https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-1175. It is unclear from the singular EPA memorandum memorializing the meeting whether, for example, EPA received feedback on the Rule as it relates to both the

electric power industry or the natural gas pipeline transportation industry, both of which fall under FERC's primary jurisdiction. Overall, commenters, including Kinder Morgan, expressed concerns regarding system reliability. EPA did not meaningfully address these important concerns on the record, in particular with respect to pipeline engines.

60. Because natural gas is a foundational building block in the American economy, natural gas pipeline service interruptions pose significant harms to the public interest. Service interruptions can lead to electric power outages, heating outages, and delays to industrial supply chains.

61. Given the considerable number of engines that require controls (approximately 360 to 443), Kinder Morgan will not be able to fulfill its obligation of continuity of service in all cases. In particular, based on my knowledge and experience of the complexity of engine installations, I expect that Kinder Morgan will need to take pipeline engines out of service to complete retrofits, timeframes for which will depend on the complexity of the modification.

62. Ordinarily, most maintenance is completed by the start of the winter season to prevent disruptions to heating season needs. That said, in the south, some maintenance is performed before the summer heat so as not to impact peak cooling season needs. Either way, it is a complex evaluation that is highly sensitive to peak demand on a particular pipeline segment. It is Kinder Morgan's practice that prior

to the next maintenance season, all approved maintenance and project activities are reviewed and an initial outage schedule is developed. The schedule takes into consideration a variety of factors to minimize interruptions. As impacts are calculated using modeling, consolidation or separation of maintenance and project activities are recommended to minimize outage impacts and durations. These recommendations are reviewed by key stakeholders within Kinder Morgan. A final outage schedule is developed just prior to the start of maintenance, which is then further refined and updated throughout the maintenance season.

63. To make clear the gravity of Kinder Morgan's concerns regarding system capacity, Kinder Morgan performed computer simulation modeling on two of its transmission pipelines to evaluate the pipeline system capacity impacts that will result during implementation of the Rule. In particular, Kinder Morgan modeled its Tennessee Gas Pipeline (TGP) and the Natural Gas Pipeline Company of America LLC (NGPL) pipelines. TGP is a bi-directional pipeline system that transports natural gas supplied from the Northeastern United States, to diverse end-use demand markets including New York City and Boston in the Northeast, the Louisiana and Texas Gulf Coast, and Mexico, and back. TGP offers more than 1.6 million compression horsepower, 11,760 miles of pipeline, and 75.5 billion cubic feet of working natural gas storage. NGPL is the largest transporter of natural gas into the high-demand Chicago-area market, as well as one of the largest interstate pipeline

systems in the country. NGPL offers approximately 9,100 miles of pipeline, more than 1 million compression horsepower and 288 billion cubic feet of working natural gas storage. The pipeline system provides its customers access to all major natural gas supply basins.

64. The model calculated the amount of gas that would not be delivered to Kinder Morgan's customers if Kinder Morgan took engines offline to retrofit or modify with the required control technologies. The amount of gas was calculated in dekatherms per day (Dth/d). For perspective when considering the results of the model, based on information available through the U.S. Energy Information Administration, during the winter months, approximately 1,000 Dth/d of natural gas serves approximately 3,000 homes per day,[13] and 1,000 Dth/d of natural gas in the summer serves approximately 3,600 homes per day.[14] These modeling scenarios were based on June 2023 delivery obligations, and the modeling did not account for any other maintenance or outages, which is expected to have a negative compounding effect on the calculated capacity impacts.

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[13] *EIA forecasts U.S. winter natural gas bills will be 30% higher than last winter*, U.S. ENERGY INFORMATION ADMINISTRATION (Oct. 25, 2021), https://www.eia.gov/todayinenergy/detail.php?id=50076#:~:text=For%20households%20that%20use%20natural,demand)%20compared%20with%20last%20winter.

[14] *EIA expects 2019 summer average residential electricity use to be lowest in five years*, U.S. ENERGY INFORMATION ADMINISTRATION (April 18, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39132.

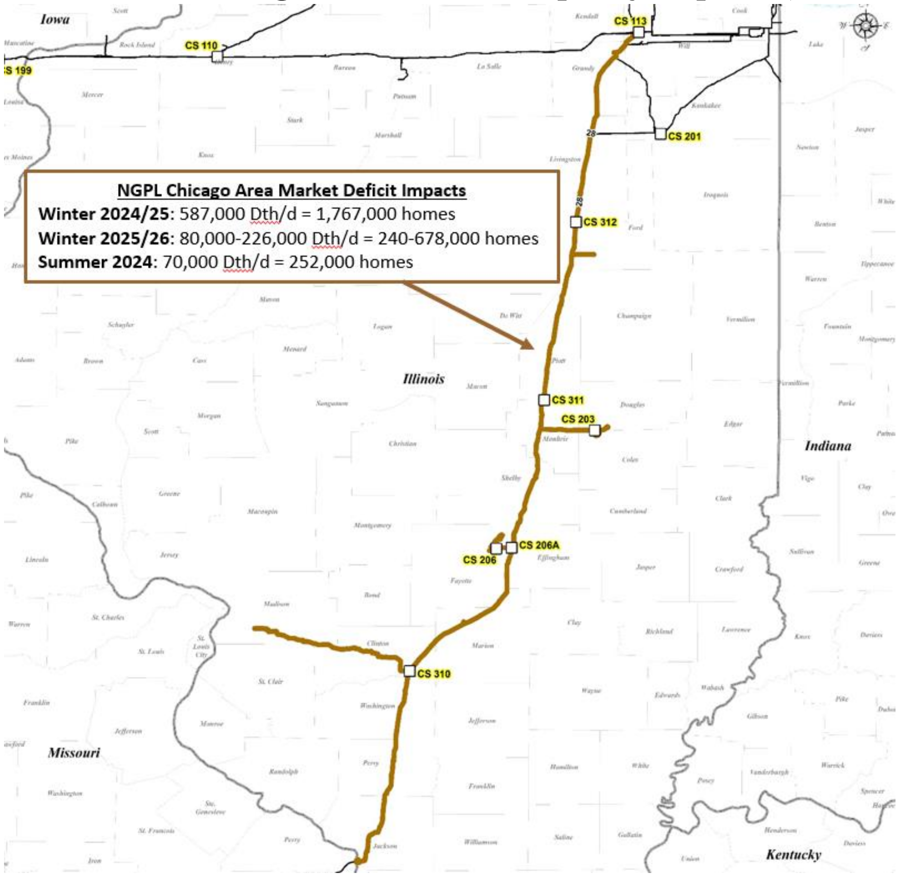
65. Kinder Morgan ran two general scenarios in the model. The first scenario analyzed system capacity impacts on the affected sections of the TGP and NGPL pipelines, assuming Kinder Morgan completed all engine modifications required across those pipeline systems by May 1, 2026.[15] The second scenario analyzed system capacity impacts on the TGP and NGPL pipelines, considering implementation of the engine retrofits in the amount Kinder Morgan reasonably believes it can accomplish by May 1, 2026. In this second scenario, to ensure compliance with the Rule, this second model run assumed that Kinder Morgan would shut-down any engines subject to the Rule as of May 1, 2026 that do not meet the nitrogen oxides emissions thresholds, because the sweeping exceptions to the Rule offer no regulatory certainty. For purposes of this Declaration, I provide a summary of three specific impacts to exemplify the types of capacity constraints that will be caused by the Rule, and which EPA failed to consider.

66. The first example summarizes the capacity impacts from the first scenario—compliance by May 1, 2026—on a segment of NGPL that services the greater Chicago area. This area is a high-demand market, especially in the winter

[15] Out of an abundance of clarity, Kinder Morgan cannot achieve compliance across its entire fleet by May 1, 2026 due to vendor availability, supply chain, permitting, and the significant number of engines subject to the Rule. This modeling exercise, however, exemplifies the critical component of harm to both the public and Kinder Morgan that EPA failed to consider by requiring a 31-month compliance timeline.

months, which makes this a particularly sensitive market. And, NGPL provides approximately 60 percent of the natural gas to the Chicago area market. The analysis, reflected in Figure 3, below, shows that in the winter heating season months of 2024 and 2025, NGPL would be unable to provide approximately 587,000 Dth/d of natural gas. This equates to an inability to provide the natural gas necessary to heat approximately 1,761,000 homes. This includes the compression located at storage fields on this line, which are required to meet daily peak demand on the coldest, and thus most critical, days in the winter. Implementing the Rule could result in a 20 percent overall deficit in meeting the Chicago market peak demand on winter days. Moreover, the reduction in storage capacity on this system will also substantially increase the cost of natural gas for consumers.

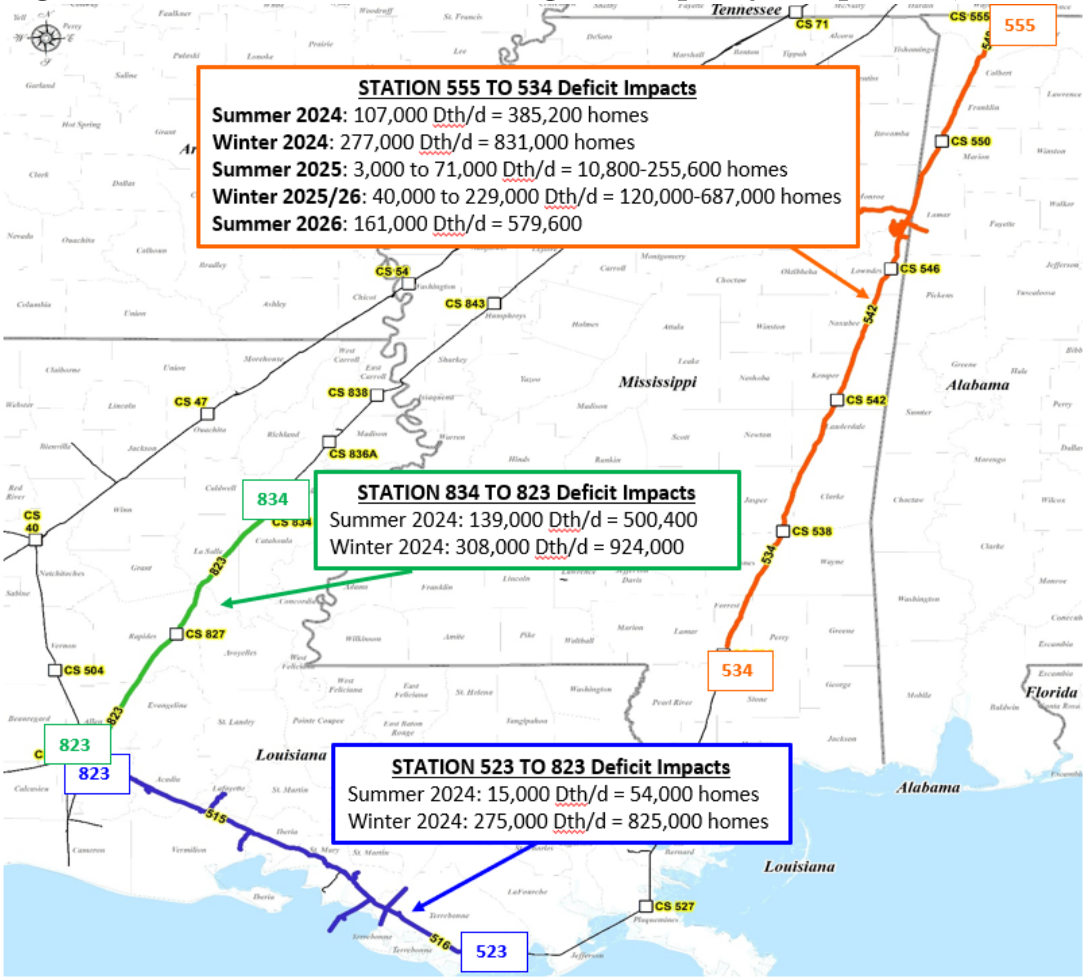
Figure 3: NGPL Chicago Area Market Capacity Impacts (Scenario 1)



67. Kinder Morgan also evaluated a segment of the TGP under the first scenario—compliance by May 1, 2026. This segment of TGP services the Gulf Coast region (Alabama, Mississippi, and Louisiana). The analysis, reflected in Figure 4, below, shows a multitude of capacity impacts, peaking in the winter months of 2024 at a deficit of 277,000 Dth/d of natural gas (Station 555 to 534 impacts). Importantly, this portion of TGP currently serves six power plants. Those power plants generate enough electricity to serve millions of homes, commercial loads, and industrial operations, daily. Kinder Morgan's implementation of the unreasonable deadline in the Rule would impede Kinder Morgan's ability to serve those power plants, which

in turn would impede the power plants' ability to provide electricity to millions of consumers. This is just one pipeline segment of the TGP system, and multiple other segments will be impacted.

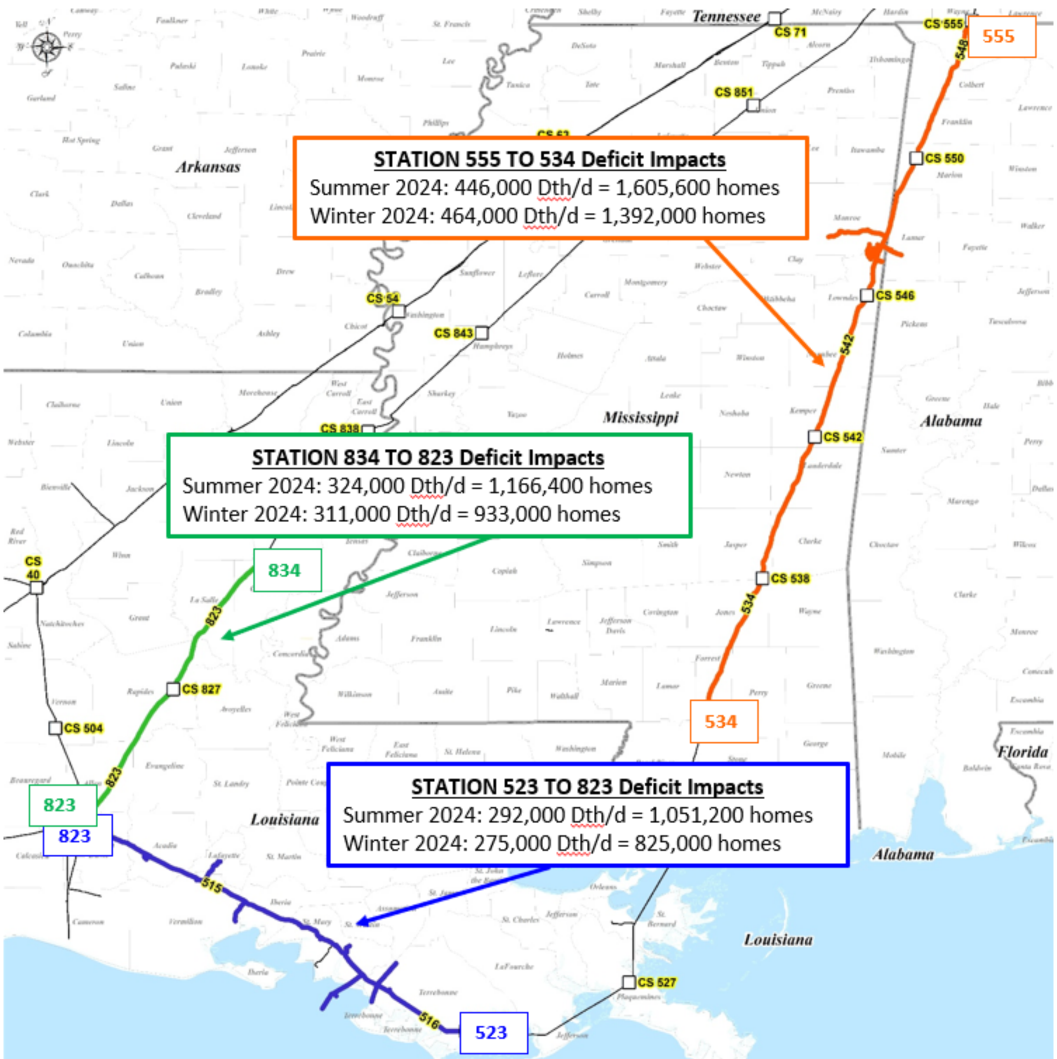
Figure 4: TGP Gulf Coast Region Capacity Impacts (Scenario 1)



68. The following analysis summarizes the capacity impacts modeled on the same TGP Gulf Coast region, assuming a schedule Kinder Morgan reasonably expects to retrofit pipeline engines by May 1, 2026. This model assumes Kinder Morgan shuts down non-compliant pipeline engines after May 1, 2026, as reliance

on any exceptions is not a reasonable regulatory approach. The model shows that there are significant service interruptions, in both winter and summer months. As indicated above, this portion of the TGP system primarily serves power plants, which would means there could be loss of service to consumers, including residential, commercial, and industrial.

Figure 5: TGP Gulf Coast Region Capacity Impacts (Scenario 2)



69. By requiring every major transmission pipeline system in the United States to take pipeline engines offline at the same time, the options for temporarily re-routing flow of natural gas to the consumer will be limited. Bottom line, Kinder Morgan is greatly concerned about providing reliable service to the public.

Kinder Morgan will Face Additional Financial Harm (Not Considered by EPA) For Failure to Provide Continuity of Service in Favor of Compliance with the Rule.

70. Service interruptions also mean that Kinder Morgan will incur additional financial harm from being unable to meet its FERC obligations to customers—a harm that EPA did not consider, even in its Regulatory Impact Analysis. Natural gas shippers who contract for firm capacity on a FERC-regulated interstate transmission pipeline typically pay two charges to transport gas on a pipeline. The first charge, called a "reservation charge," is based on the amount of pipeline capacity reserved by the shipper. The second charge, called a "usage charge," is based on the actual amount of gas transported by the shipper. When transmission pipeline service is interrupted for any reason, FERC policy requires Kinder Morgan to provide its shippers with "reservation charge credits"—essentially a refund of the reservation charge the shipper paid to reserve pipeline capacity. FERC's policy to refund reservation charges is crafted to ensure that service provided is as reliable as possible to minimize the harm to the public and financial injury caused by service outages.

71. By way of example, consider Figure 4, described in Paragraph 67 above. In that example, if TGP failed to deliver the deficit capacity for pipeline segments 500 and 800 shown in Figure 4, over the course of seasons shown along the three highlighted portions of the pipeline system, TGP would have to refund reservation charge credits in the amount of approximately $120 million. This scenario offers just one of many examples of the financial impact Kinder Morgan could incur from failure to ensure continuity of service under the Natural Gas Act. Kinder Morgan will face this situation innumerable times through implementation of the Rule.

72. EPA did not consider these financial impacts of the required refund of reservation charge credits in its cost analyses. Kinder Morgan's analysis shows that when distributing the $120 million reservation charge credits across the applicable pipeline engines, *each individual engine* will see an additional capital cost in the range of $750,000 to $5,400,000 million, which increases the final cost-per-ton for each pipeline engine by multiple thousands of dollars. This is consequential when the cost threshold is the critical "amount" required by the Clean Air Act.

73. If Kinder Morgan is put in the untenable position of continuing to provide natural gas services to its customers and the public, but failing to meet the compliance obligations of the Rule, Kinder Morgan would be exposed to civil, and even potential criminal, liability by EPA. For a facility that fails to comply with the

Rule, EPA can seek a permanent or temporary injunction on the source and/or fines up to $117,468 (adjusted for inflation) per day for each violation (per engine). In addition to the civil penalties, the Clean Air Act includes criminal penalties for knowingly violating a FIP.

The Rule's Enormous Costs of Compliance are Not Recoverable From the Government.

74. Given the magnitude of the changes necessary for Kinder Morgan's engine assets to comply with the Rule by the May 1, 2026 deadline, the size and complexity of these engines, and the long lead time for installations, Kinder Morgan will be forced to incur substantial costs during this Court's consideration of the Rule to ensure compliance if the Rule is ultimately upheld. Kinder Morgan simply cannot afford to wait for the resolution of legal challenges to the Rule, or wait for EPA to determine at a later date it is going to extend the May 1, 2026 deadline, before installing controls.

75. The costs of compliance are not recoverable from EPA or any other branch of federal or state government. For FERC-regulated pipelines, which includes the majority of Kinder Morgan's pipelines subject to the Rule, there is no way to recover these costs through existing FERC-approved rates. There are only limited circumstances, and no guarantee, for recovery of *future* costs through FERC's ratemaking process. For non-FERC regulated pipelines, which includes

several of Kinder Morgan's pipelines subject to the Rule, there is no regulatory mechanism for Kinder Morgan to seek revisions to future rates.

76. The financial impact of reservation charge credits as described above are also unrecoverable under FERC policy, further exacerbating the financial harm to Kinder Morgan to ensure compliance during the Court's consideration of the Rule.

77. Nor would the costs be recoverable from Kinder Morgan's vendors. Kinder Morgan must pay significant non-refundable deposits even to secure a vendor's services, which Kinder Morgan must do 6 to 12 months before an engine is offline to ensure continuity of service. Vendors also require timely, and incremental payment as an emissions control project is in development and through to completion. For example, many vendors require 30 percent of a payment due upon acceptance of the purchase order, 20 percent due upon submittal of drawings for approval, 30 percent due upon material shipment, and 20 percent due upon final commissioning of the unit. Once spent, the costs are not recoverable.

78. As a result, Kinder Morgan will not be able to prioritize the public interest by serving all of its customers. Kinder Morgan also will not recover any costs it incurs for compliance with the Rule, and will not be able to salvage the lost business opportunities resulting from the Rule's forced reallocation of funds. These harms are irreparable and thus preventable only by a stay of the Rule.

79. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 26th day of July, 2023.

Kenneth W. Grubb

Kenneth W. Grubb
Chief Operating Officer
Kinder Morgan, Inc.

IN THE UNITED STATES CIRCUIT COURT
FOR THE DISTRICT OF COLUMBIA CIRCUIT

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA and AMERICAN PETROLEUM INSTITUTE, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, Respondents.	Case No. 23-____

DECLARATION OF ENBRIDGE IN SUPPORT OF INTERSTATE NATUAL GAS ASSOCIATION OF AMERICA'S MOTION FOR STAY

I, Thomas V. Wooden Jr., declare that the following is true and correct:

1. I am over the age of twenty-one years old and have personal knowledge of the statements made herein.

2. I am Vice President (VP) of the Gas Transmission and Midstream Engineering & Asset Integrity Management for Spectra Energy Transmission Services, LLC, the general partner of Texas Eastern Transmission, LP, which are indirectly owned by Enbridge (U.S.) Inc. (hereinafter "Enbridge"), a member of the Interstate Natural Gas Association of America ("INGAA").

3. As the owner and operator of numerous reciprocating internal combustion engines used to support pipeline compressor and storage facilities rated at 1,000 horsepower or more ("pipeline engines"), Enbridge is directly regulated by the Final Rule being challenged, Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36654 (June 5, 2023) ("Final Rule").

4. I am the Vice President of Gas Transmission and Midstream Engineering and Asset Management for Enbridge. I am charged with overseeing engineering, technical support and asset optimization for Enbridge gas transmission pipelines in both the U.S. and Canada. I earned a Bachelor's degree in Petroleum Engineering from Marietta College in May 1984. In December 1991, I earned a Master's degree in Petroleum Engineering from the University of Houston. I have been employed with Enbridge and its predecessor corporations, Spectra Energy Corp, Duke Energy Corporation, PanEnergy Corp, Panhandle Eastern Corp, and Texas Eastern Corporation, since 1985. During that time, I have worked in various operations and leadership positions, including Vice President of US Field Operations, Vice President of Northeast Operations, General Manager of the East Division, Director of Technical Operations for the Central Region, and Vice President of Gas Transmission and Midstream Operations. Most recently I was appointed to Vice President of Gas Transmission and Midstream Engineering and Asset Management. I have been in my current position since April 1, 2019. Part of the responsibilities of my current job include helping Enbridge prepare to comply with the Final Rule. This declaration is based on my personal knowledge of facts and information related to Enbridge's business and strategy for compliance with the Final Rule, as well as my discussions with individuals in departments Environment, Engineering Reliability and Risk, Legal, Asset Management, Projects, Operations, Regulatory, Safety, Commercial Operations who are responsible for implementing the Final Rule.

5. The Final Rule will become effective on August 4, 2023, and it requires that pipeline engines with a maximum rated capacity of 1,000 horsepower or more within 20 states comply with certain emission limitations by the beginning of the 2026 ozone season in May 2026. 88 Fed.

Reg. at 36654, 36820. Enbridge has 176 regulated pipeline engines in the States that EPA has made subject to the Final Rule.

6. To comply with the Final Rule when emission limitations take effect in May 2026, Enbridge has already initiated work necessary for compliance. It will take several years to install the necessary pipeline engine emission controls. Enbridge estimates $350 million will be spent within the next 12-18 months on design, engineering, parts, and employee time while the case is being litigated. If States where there is a judicial stay are excluded from consideration, the cost is $228 million.

Enbridge Operations

7. Enbridge's U.S. Transmission System is an interstate natural gas pipeline network consisting of just over 14,000 miles of pipe and 3.4 million horsepower of compression equipment. U.S. Transmission operates in 30 states and offshore from the southern tip of Texas, across to Florida, and up into New England and moves about 20% of all gas consumed in the U.S.

8. Enbridge owns 176 pipeline engines with a capacity of 1,000 horsepower or more in the States of Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Missouri, Mississippi, New Jersey, Ohio, Pennsylvania, Texas, and Virginia. Each of these pipeline engines is subject to the Final Rule. There are 124 engines in States where the State Implementation Plan (SIP) disapproval is stayed (Arkansas, Kentucky, Louisiana, Missouri, Mississippi, Texas) and 52 engines are in States that are not stayed.

Enbridge Will Spend Millions of Dollars in Potentially Unnecessary Compliance Costs While the Court is Considering INGAA's Challenge

9. It is my understanding that the Court may take 12 to 18 months before it will rule on INGAA's challenge to the Final Rule. Enbridge cannot wait until the Court issues its decision to begin working to comply with the Final Rule. Although the April 30, 2026 deadline may seem far

away, retrofitting emission controls involves a multi-step process that involves long lead times for analysis of engines to be controlled, design/engineering/procurement of equipment, and contracting with specialized contractors to install and test equipment. It is not feasible for Enbridge and the rest of our industry to all plan to install new controls on 3000 pipeline engines across multiple states by April 2026. Even if Enbridge begins retrofitting its pipeline engines now Enbridge is not likely to finish the necessary work before the compliance deadline. Enbridge is requesting this stay pending outcome of the litigation to avoid potentially unnecessary compliance costs while the court is considering INGAA's challenge.

10. Since pipeline engines are large, complex pieces of equipment, installing emission controls requires design and engineering specific to each type of engine. The design, engineering, and installation of new controls requires Enbridge to retain specialized contractors, of which there are few with the necessary expertise with pipeline engines. Because these specialized contractors have limited capacity and are already seeing increased demand due to the Final Rule, Enbridge has hired three design firms and initiated emission control work design and development, however, the available pool of system integrators and construction contractors is limited. Emission control installations have two aspects: on-engine work and off-engine work. System Integrators perform on-engine work and electrical/mechanical/construction contractors perform off-engine work. There are only two system integrators in North America (and the world) that provide and install these types of emission controls, Cooper Machinery Services (CMS) and Siemens-Enginuity. EPA's research indicates that there will be capacity to retrofit up to 150 units per year. When installing emission controls on pipeline engines, only 25%-30% of the work and costs are associated with on-engine work which is provided by the system integrators. The remaining 70%-75% of the work and costs involve off-engine

infrastructure additions and auxiliary system upgrades required to support the on-engine emission controls. Enbridge, and each of the other pipeline companies all draw from the same pool of design firms, suppliers, and construction companies to perform this work. Representative documentation in support of these costs is attached as Exhibit A. Enbridge believes EPA's cost analysis is grossly understated by not considering the full scope of emission control installation, and further, EPA's own documentation and analysis shows the volume of affected units cannot be retrofitted by the compliance deadline.

11. The pipeline engines regulated by the Final Rule are vital to Enbridge's operation of its interstate transmission infrastructure, delivering natural gas for distribution to residential, commercial, and industrial users. While the Court is considering INGAA's challenge to the Final Rule, Enbridge will have to begin taking its engines off-line to start emission control installation. Emission control installation at a single station could take between 3 and 6 months per unit or 6 to 12 months per station depending on the number of units and how many units can be done at the same time. This means that, over the next 12 to 18 months, Enbridge must shut down pipeline engines for several months at a time, even during the peak summer and winter seasons which will limit natural gas services. Every other company subject to the Final Rule will also be executing design, procurement, and installation of emission controls on their pipeline engines at the same time increasing constraints on natural gas deliveries. With pipeline engines for multiple companies being off-line at the same time, the options for temporarily re-routing the flow of natural gas from customers to end users will be limited and a threat to industry-wide system reliability.

12. Outages for retrofit will cause capacity restrictions and have the potential to impact our firm (uninterruptable) services. These firm services are counted upon by a wide range of customers

to provide heat and power, including small municipalities, local distribution companies, electric generators, manufacturers and industrial end users and Liquefied Natural Gas (LNG) exporters. Natural gas is also a raw material in a number of manufacturing processes, in fertilizer, ammonia, and chemical manufacturing industries. Each one of these groups has their own constituents that depend upon a reliable supply of natural gas. Interruption in system-wide flows of natural gas has larger economic impacts including employment, reliability of the electric grid, and the cost of electricity.

13. Retrofitting pipeline engines involves significant capital costs. Based on Enbridge's most recent 2019 emission control installation, retrofitting a single pipeline engine with the emission controls required by the Final Rule will cost approximately $11.5 million. Costs could be higher given ongoing supply chain constraints. Enbridge estimates that it will spend approximately $350 million within the next 12-18 months on design, engineering, parts, and employee time in order to comply with the Final Rule's emission limitations by May 2026. Enbridge believes that EPA's cost estimates are grossly understated.

14. Enbridge will need to divert funds from other capital projects planned for the next 12-18 months and beyond to fund work necessary to comply with the Final Rule. Enbridge currently estimates the overall cost impact of the Final Rule to be approximately $1 billion. To absorb this level of capital cost, system modernization plans are also being deferred to accommodate the funds required by the Final Rule.

15. Pipeline engine modifications require an accompanying permit modification. In addition to the normal workload, Enbridge's staff will be required to spend a significant amount of time assembling the information and supporting documentation needed to apply for the necessary permit modifications and to coordinate with state permitting authorities as they process those

applications. This typically includes conference calls with state permitting staff, responding to requests for additional information, and meetings with staff and contractors. The permitting required for this rule will be an additional draw on resources at Enbridge and the affected State Agencies when the entire industry is re-permitting facilities in the compliance timeframe.

16. Altogether, Enbridge estimates that, in the absence of a stay, it will spend approximately $350 million to comply with the Final Rule just during the next 12-18 months. Representative documentation in support of these costs is attached as Exhibit A.

17. Enbridge is aware that the Final Rule includes a possible option for a facility-wide averaging plan. 88 Fed. Reg. at 36,820. However, facility-wide averaging is not a viable option for Enbridge for the following reasons:

First, the Final Rule only allows "any owner or operator of an affected unit to *propose* a Facility-Wide Averaging Plan that would, *if approved by EPA*, provide an alternative means for compliance with the emissions limits in this Final Rule." At this time, there are no published criteria to help a company understand what EPA will consider 'adequate' nor is there a defined timeframe for EPA to act upon those proposals. Unless and until the company receives approval from EPA for averaging plan, a company must proceed with emission control work per the Final Rule.

Second, EPA believes that Facility-Wide Averaging will reduce the number of industry wide pipeline engines affected by the Final Rule from 3000 units to 900 units, but this option is not practicable for Enbridge for the following reasons:

- EPA's Prevention of Significant Deterioration (PSD) rules require a company to evaluate an entire site rather than individual units during permit modifications associated with this type of work. The controls necessary to comply with the averaging provision would increase emissions of other pollutants, thus requiring a full PSD analysis for each entire site. If a PSD permit is required, which seems likely, that process itself could take several years and would require the installation of additional controls.

- A company's certificate obligations under Federal Energy Regulatory Commission (FERC) rules require that the full capacity of a station be available to customers year-round. EPA added the facility-wide averaging provision after the comment period closed to reduce the number of affected units but failed to consider PSD and/or FERC certificate obligations that may continue to require emission controls on all 3000 units. Facility averaging will prevent the sites from operating at full capacity for 5 months out of the year unless emission controls are installed on all engines, which is precisely what the averaging program is designed to avoid.

18. Without a stay, should the Court later invalidate the Final Rule, Enbridge will have wasted millions of dollars working to comply with the Final Rule's emission limitations. To the best of my knowledge, the emission controls that will need to be installed to comply with the Final Rule are not required for compliance with any other federal or state regulation and there is no mechanism to recover the costs of these emission controls from EPA or any other branch of the federal government.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed in Houston, Texas on this 19 day of July, 2023.

Thomas V. Wooden, Jr.

Exhibit A

Final project costs for CB work at Perulack

Perulack 2019 (Leidy) Clean Burn Costs

Exported from EcoSys on 06/08/2023 12:25:57			
GTM009 Project Cost Data			
WBS ID	WBS Description	Major Task	Incurred Cost
CE.000147.006.02.01	CON - Mobilization	Construction	148,210
CE.000147.006.02.02	CON - Site Work	Construction	111,179
CE.000147.006.02.03	CON - Foundations	Construction	369,199
CE.000147.006.02.04	CON - Equipment & Structures	Construction	501,796
CE.000147.006.02.09	CON - Fab & Install	Construction	350,044
CE.000147.006.02.10	CON - Pressure Testing/ Start-Up	Construction	38,469
CE.000147.006.02.11	CON - Electrical	Construction	421,691
CE.000147.006.02.12	CON - Instrumentation	Construction	178,925
CE.000147.006.02.13	CON - Paint/ Coating/ Insulation	Construction	103,417
CE.000147.006.02.14	CON - General Expenditures	Construction	289,856
CE.000147.006.02.25	CON - Performance/ Payment Bonds	Construction	303
CE.000147.006.02.26	CON - Contractor Fee	Construction	321,631
CE.000147.006.02.29	CON - Change Orders	Construction	10,897
CE.000147.006.02.31	CON - EPC/EPCM Prime Contractor	Construction	350,000
CE.000147.006.03.01	MAT - Prime Mover and Compr Sets	Procurement	1,759,152
CE.000147.006.03.02	MAT - Air Compressors	Procurement	358,010
CE.000147.006.03.03	MAT - Generators	Procurement	0
CE.000147.006.04.01	MAT - Coolers	Procurement	0
CE.000147.006.04.02	MAT - Heaters	Procurement	21,872
CE.000147.006.04.03	MAT - Buildings	Procurement	0
CE.000147.006.04.04	MAT - Tanks/Vesseles	Procurement	46,538
CE.000147.006.04.05	MAT - Scrubbers/Filter Separatrs	Procurement	95,275
CE.000147.006.04.07	MAT - Fabrications - General	Procurement	112,646
CE.000147.006.05.03	MAT - Pipe - 14in. & Smaller	Procurement	21,837
CE.000147.006.06.03	MAT - Valves - 14in. & Smaller	Procurement	62,153
CE.000147.006.07.01	MAT - Materials - General	Procurement	2,736
CE.000147.006.07.02	MAT - Fittings & Flanges	Procurement	10,138
CE.000147.006.07.04	MAT - Freight & Handling	Procurement	42,177
CE.000147.006.08.01	MAT - Power	Procurement	83,599
CE.000147.006.08.02	MAT - Controls	Procurement	94,975
CE.000147.006.08.03	MAT - Instrumentation	Procurement	36,819
CE.000147.006.08.04	MAT - Meters	Procurement	20,730
CE.000147.006.09.02	MAT - Transmission Departments	Procurement	103,641
CE.000147.006.10.01	ENG - Design Svcs	Engineering	1,049,156
CE.000147.006.10.02	ENG - Testing Svcs	Engineering	0
CE.000147.006.10.06	ENG - Engineering Design Consult	Engineering	171,283
CE.000147.006.10.07	ENG - Commissioning Svcs	Engineering	318,325
CE.000147.006.10.08	ENG - Close Out & As-Builts	Engineering	11,479
CE.000147.006.10.09	ENG - EPC/EPCM Design Svcs	Engineering	75,814
CE.000147.006.10.13	ENG - EPC/EPCM Commissioning Svcs	Engineering	167,854
CE.000147.006.10.14	ENG - EPC/EPCM Close Out & As-Builts	Engineering	83,927

CE.000147.006.11.02	ROW - Acquisitions	Land / ROW	7,267
CE.000147.006.11.04	ROW - Agents	Land / ROW	13,948
CE.000147.006.12.01	ENV - Bio Field Surveys	Environment	27,070
CE.000147.006.12.02	ENV - Cultural Resource Surveys	Environment	0
CE.000147.006.12.04	ENV - Permit Application-Fed,State,Local	Environment	9,243
CE.000147.006.12.05	ENV - Air Permitting	Environment	63,693
CE.000147.006.12.07	ENV - Environmental Inspection	Environment	0
CE.000147.006.12.11	ENV - Waste Sampling / Disposal	Environment	236,436
CE.000147.006.12.13	ENV - Post Construct. Monitoring/Report.	Environment	0
CE.000147.006.13.01	CSV - Core Staff Svcs	Construction	321,575
CE.000147.006.13.02	CSV - Inspection Svcs	Construction	363,799
CE.000147.006.13.03	CSV - Survey Svcs	Construction	3,324
CE.000147.006.13.04	CSV - X-Ray / UT Svcs	Construction	120,742
CE.000147.006.13.05	CSV - Consulting Svcs	Construction	31,250
CE.000147.006.13.07	CSV - General Construction Expns	Construction	26,886
CE.000147.006.14.01	ICS - Supply Chain Svcs	Management	34,039
CE.000147.006.14.02	ICS - Transmission Svcs	Management	65,238
CE.000147.006.14.03	ICS - PR Svcs	Management	0
CE.000147.006.14.04	ICS - Legal Svcs	Management	0
CE.000147.006.14.05	ICS - Quality & Expediting Svcs	Management	11,983
CE.000147.006.14.07	ICS - GR Svcs	Management	126,500
CE.000147.006.15.05	GEN - Insurance & Bonds	Management	0
CE.000147.006.15.06	GEN - General Expenses	Management	55,418
CE.000147.006.16.01	EMP - Engineering Labor & Expens	Management	822,855
CE.000147.006.16.02	EMP -Transmission Labor & Expens	Management	187,069
CE.000147.006.16.04	EMP - A&G CWIP	Management	235,684
CE.000147.006.17	Contingency	Contingency	0
CE.000147.006.18	Escalation	Escalation	0
CE.000147.006.20	Salvage	Management	(2,038)
CE.000147.006.FIN.ALLOC	ALLOCATIONS	Management	1,891
CE.000147.006.Z.90.90.1	AEDC	AFUDC	482,038
CE.000147.006.Z.90.90.2	AIDC	AFUDC	84,003
CE.000147.028.16.01	EMP - Engineering Labor & Expens	Management	14,269
CE.000147.028.16.06	EMP - A&G RWIP	Management	4,935
CE.000147.028.22	Retirement	Construction	228,869
			11,523,739

IN THE UNITED STATES CIRCUIT COURT
FOR THE DISTRICT OF COLUMBIA CIRCUIT

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; AMERICAN PETROLEUM INSTITUTE,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; MICHAEL S. REGAN, Administrator, U.S. EPA

Respondents.

Case No. 23-1193

DECLARATION OF SCOTT YAGER IN SUPPORT OF INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA'S MOTION FOR STAY

I, **SCOTT YAGER**, declare that the following is true and correct:

1. I am over the age of twenty-one years old and have personal knowledge of the statements made herein.

2. I am the Vice President of Environment at the Interstate Natural Gas Association of America ("INGAA").

3. INGAA is a trade association that advocates for the regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America. Its 26 member companies operate almost 200,000 miles of interstate pipelines that transport natural gas from producers to consumers, providing critical energy needed to heat our homes, cook our food, fuel our factories, and generate electricity. Natural gas is a domestically produced, affordable, and foundational fuel source that the U.S. will rely on for decades to come, and pipelines are the safest, most reliable, and most affordable way to deliver natural gas to consumers.

Approximately one-third of the energy consumed in the U.S. travels through natural gas infrastructure.

4. Protecting the environment is a top priority for INGAA members, and natural gas is the cleanest burning fossil fuel. As demand for energy increases, expanded use of natural gas reduces overall greenhouse gas emissions by offsetting the use of higher carbon-intensive fuels. According to the International Energy Agency, switching from coal to gas reduces emissions by 50% when producing electricity and by 33% when providing heat. INGAA members implement pipeline integrity and maintenance programs as well as emissions reduction programs to further improve the industry's climate footprint.

5. INGAA and its members have a strong interest in supporting the efficient, transparent, and predictable regulation of natural gas pipeline facilities and related equipment.

6. To operate their pipelines, INGAA member companies own and operate numerous units to compress natural gas, which enables transportation of natural gas from the production sites to end-users across the country. These units ("compressor units") include combustion turbines and reciprocating internal combustion engines, the latter of which ("pipeline engines") are regulated by the rulemaking being challenged, *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards*, 88 Fed. Reg. 36,654 (June 5, 2023) ("Final Rule").

7. I have worked at INGAA since 2022 and my responsibilities include advocating for federal environmental policies, laws, and regulations that support the development and operation of safe, reliable, and environmentally-sound interstate natural gas transportation and storage infrastructure. Part of this advocacy includes working with our member companies to analyze, understand, and file comments on the U.S. Environmental Protection Agency ("EPA")

proposal that led to the Final Rule under review. *See Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule").

INGAA Member Companies Own Or Operate Approximately Two-Thirds Of The Pipeline Engines Subject To The Final Rule, The Majority Of Which Will Require Controls

8. The Final Rule becomes effective on August 4, 2023, and it requires pipeline engines with a maximum rated capacity of 1,000 horsepower or more within 20 states[1] to comply with certain emissions limits by May 2026. 88 Fed. Reg. at 36,654, 36,820. EPA estimates that 3,005 pipeline engines meet or exceed 1,000 horsepower capacity in the 20 states. *Id.* at 36,842. INGAA members own or operate approximately 1,900 of those engines.

9. At this time, we cannot ascertain the exact number of engines that will require the application of controls to meet the Final Rule's emissions limits because EPA created several exemptions and alternative compliance approaches, including some that require EPA approval, in its discretion. Specifically, EPA exempted emergency engines and certain engines subject to New Source Performance Standards (40 C.F.R. Part 60, Subpart JJJJ), provided for facility-wide averaging, and allowed pipeline operators to petition for an alternative emissions limit in cases of technical impossibility or extreme economic hardship. 40 C.F.R. §§ 52.40(e), 52.41(a)-(b), (d). It is unclear how EPA will apply these provisions or to what extent INGAA members will be able to take advantage of them. Based on our current best estimates, which attempt to account for the exemptions and alternative compliance approaches, INGAA members believe that approximately 1,220 pipeline engines will require controls to comply with the Final Rule.

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[1] EPA is requiring emissions reductions from natural gas pipelines to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

Of these, 520 are located in states that do not have a judicial stay of the Final Rule or the EPA SIP disapproval that preceded issuance of the Final Rule, and approximately 700 are located in states with judicial stays.

Absent A Stay, INGAA's Members Will Incur Hundreds Of Millions, If Not Billions, In Compliance Costs During The Next 12 To 18 Months

10. INGAA estimates that its members will have to spend $2.4 to $6.1 billion to comply with the Final Rule's emissions limits. Of that cost, INGAA estimates up to 35% of the total (or approximately $840 million to $2.1 billion) would need to be spent in the next 12-18 months while this case is being litigated in this Court to attempt to meet the Final Rule's compliance deadline for all engines subject to the Rule. If units located in states with a judicial stay are excluded from consideration, the cost of installing controls on the engines in states that remain subject to the Final Rule still exceeds $1 billon, with up to $300 million or more of that total likely to be expended in the next 12 to 18 months.

11. These compliance costs are so large because installing emissions controls onto pipeline engines is an expensive process and the installations will be implemented across approximately 1,220 pipeline engines, a project the scale of which has never been attempted by the industry (or the regulatory permitting agencies).

12. The actual costs could be higher than these estimates because the Final Rule forces the entire industry to add controls to pipeline engines at once. When pipeline companies compete for contractors and equipment, the increased demand drives up costs.

13. Based on service provider cost projections provided by its members for lean burn engines, INGAA estimates that its members will spend approximately $2 to $5 million per engine to install controls to comply with the Final Rule's emissions limits. In some cases, INGAA's members also will need to make additional facility upgrades and do support work for the engine

controls that will significantly increase the costs. For example, one INGAA member reported that it recently spent over $11 million to retrofit a single pipeline engine due to the additional facility upgrades and support work that was needed for that particular project.

14. The Final Rule requires these expensive controls even on certain pipeline engines that, more often than not, do not operate. During high demand periods, or when other compressor units are offline due to planned or unplanned maintenance, INGAA's members might run (or prepare to run) all of their pipeline engines to meet human needs so the lights stay on and houses stay warm or cool, depending on the season. During other periods, however, some pipeline engines affected by the Final Rule operate as backup units and are not needed to operate. These units have overall utilization rates lower than 50%, including many with lower than 20% annually.

15. INGAA's members cannot recover these costs from the government if the lawsuit prevails. Moreover, no statute or regulation allows pipelines to recover, in real-time, the significant costs of imposing these controls from their customers. An interstate gas pipeline cannot raise its transportation rates absent authorization from the Federal Energy Regulatory Commission ("FERC"), 15 U.S.C. § 717c(d). A rate increase may be sought for *future costs*, however, the process is lengthy and expensive, with no guaranteed result. Further, some INGAA members have negotiated "stay out" provisions with their customers as part of prior rate case settlements or provide service subject to negotiated rate agreements that preclude them from increasing their contractually-defined rate for the length of the agreement – sometimes over a decade. If the company incurs costs to comply with the Final Rule during the "stay out" or rate-capped period, it may not recover those costs. Even if the pipeline can request a rate increase and FERC approves the request, the new rate only applies prospectively.

16. The Final Rule's cost to INGAA members goes beyond dollars; by diverting substantial resources to compliance, the Final Rule eliminates the opportunity to pursue other projects that would benefit pipeline customers and the environment. These projects include modernizing and/or expanding facilities, improving operational efficiencies and reliability of the system, and funding research and pilot projects on initiatives to further reduce the industry's climate footprint and other environmental priorities. If the court does not stay the Final Rule and INGAA prevails on its challenge to the Final Rule, INGAA members will have wasted hundreds of millions of dollars on engine modifications that are unnecessary to meet customer demands and that do not enhance the economic value of the engines and, in some instances, impose controls on pipeline engines that run infrequently or rarely.

INGAA Members Must Begin Work Now To Be Prepared To Comply With The Final Rule Due To The Long Lead Times Associated With Procuring The Necessary Government Approvals And Installing Emissions Controls

17. As explained below and in more detail in INGAA's comments on the Proposed Rule and in the separate declarations of INGAA's members, pipeline engines are large, complex pieces of equipment. To add emissions controls, INGAA members must develop engineering plans and designs for each engine. They must procure parts and hire specialized contractors to install and test the equipment. They must obtain a new or modified state or federal air quality permit for each engine they modify. And in some instances, they may have to obtain a prevention of significant deterioration ("PSD") permit. Each step is time-consuming and expensive, and each step becomes more difficult as INGAA members compete for limited resources in an attempt to install controls on upwards of 1,220 pipeline engines within the grossly insufficient time to comply with the Final Rule.

18. The vast majority of pipeline engines regulated by the Final Rule are lean burn engines, with the vast majority of these two-stroke cycle lean burn engines and a smaller subset of 4-stroke

cycle lean burn engines. EPA suggested that pipelines can use selective catalytic reduction ("SCR") to reduce NOx emissions on four-stroke lean burn engines, but INGAA members plan to use SCR rarely, if at all. As explained in INGAA's comments on the rule, SCR application is fairly common for larger combustion sources, such as electric utilities and large industrial boilers, but it is very rarely used in lean burn engines due to a variety of environmental, reliability, and economic reasons. Instead, INGAA members are planning to install "low emissions combustion" ("LEC") technology (also referred to as "layered combustion" by EPA) on lean burn engines to comply with the Final Rule. There are currently only two primary technology service providers that offer LEC controls for two-stroke lean burn engines, and the limited supply of both contractors and LEC technology will lead to increased costs and delays for INGAA members. Indeed, EPA has previously acknowledged market limitations for retrofitting pipeline engines, noting that "market demand could significantly exceed the available resource base of skilled professionals." *Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance* § 3.4, at 21 (Aug. 2016). This results in "substantial uncertainty" in timelines for retrofit control installation over numerous sources. *Id.* In recent years, the service provider constraints have not improved. And even if these constraints were to improve, they would have to do so in the next couple of months to enable INGAA's members to meet the Final Rule's timeline.

19. As detailed and submitted to the record with its comments, INGAA commissioned a study of upgrades to install LEC technology on existing lean burn engines in natural gas transportation, and the study demonstrates why EPA's timeline and cost estimates for retrofitting pipeline

engines are unrealistic.[2] The study used retrofits in response to potential NOx regulations triggered by the 2015 ozone National Ambient Air Quality Standards ("NAAQS") and interviews with equipment operators and equipment suppliers that serve our industry to estimate the timeline and cost to retrofit controls on pipeline engines. The study indicated that, from inception to completion, retrofitting a single pipeline engine with controls would require between one and two-and-a-half years to complete. Although INGAA published the report in 2014, its conclusions remain valid and, if anything, may underestimate the time needed to retrofit a single pipeline engine. The number of primary service providers has not increased since 2014, and vendors have advised INGAA members that the rule has forced an unprecedented level of demand for installation of technology to control NOx emissions. INGAA member Kinder Morgan reports that one of its primary contractors said that over the last 25 years, it has modified approximately 400 total engines across the entire pipeline transportation industry. The Final Rule requires INGAA member companies to modify three times that number of engines in just three years—and that is not counting the engines of operators that are not INGAA members but also must be retrofitted during the same timeframe.

20. What is more, before INGAA members can commence physical work on the engines, they must apply for and receive a new or modified air permit from the appropriate federal, state, local, or tribal air permitting authority for nearly all engines that need additional emissions control technology. This requires a significant amount of resources, first to assemble the information and supporting documentation for the application and then to respond to questions and requests for additional information from the staff of the permitting authority. Based on its

[2] Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry" (July 2014)

members' experience, including those described in the declarations submitted in support of INGAA's motion for a stay, INGAA estimates that such permitting and approval could take 90 days to two years for each facility that has pipeline engines, or longer if PSD permitting is required.

21. Even assuming the best-case scenario in which the permitting process goes smoothly and companies are able to retain contractors to install controls as quickly as possible, INGAA anticipates that a significant portion of pipeline engines that need controls under the Final Rule will not be able to comply by May 2026 due to current lack of sufficient parts and labor. EPA says that in "limited circumstances for individual facilities," operators may obtain "extensions of time to install required pollution controls and achieve the emissions rates established in this rule based on a showing of necessity." 88 Fed. Reg. at 36,749. But the "circumstances where an extension of time may be warranted for any specific facility are unknown" at this time. *Id.* Thus, to meet the deadline for as many engines as possible, and to establish a basis to apply for an extension from EPA for pipeline engines that cannot be controlled by May 2026, INGAA members must begin work immediately. In fact, they have already begun this work, and several companies have submitted declarations providing further detail on work they are doing to attempt to meet the compliance deadline.

Compliance With The Final Rule Could Threaten The Reliability Of The Country's Natural Gas System, Compromising Basic Needs

22. INGAA members design interstate natural gas pipelines to meet peak firm transportation contractual demand with little or no excess capacity. The vast majority of INGAA members operate at full capacity during peak demand periods, typically in the winter and summer months when natural gas utilities and gas-fired electric generators require natural gas to provide heat or air conditioning to American homes. In order to meet the tight timeline imposed

by the Final Rule, INGAA members will not be able to avoid installing retrofits during these peak periods, with adverse consequences for reliability.

23. The Final Rule will force INGAA members to take significant numbers of pipeline engines out of service for retrofit within the same, or affecting service to the same, geographic area. The temporary loss of multiple pipeline engines will increase the risk that our customers—local gas utilities, industrial and manufacturing companies, and gas-fired electric generators—will not be able to obtain the natural gas they need to operate.

24. INGAA members have limited ability to mitigate disruptions of service because Section 4(b) of the Natural Gas Act and the antitrust laws restrict companies' ability to coordinate their outage and maintenance schedules with other pipelines.

Conclusion

25. For all of these reasons, absent a stay, INGAA's member companies will be forced to incur hundreds of millions, if not billions, of dollars in compliance costs that are unrecoverable from the government while this case is being litigated, and they will have to take significant numbers of pipeline engines out of service, threatening disruptions to the nation's natural gas supply.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed in Washington, DC on this 27th day of July, 2023.

Scott Yager
Vice President, Environment
Interstate Natural Gas Association of America

IN THE UNITED STATES CIRCUIT COURT
FOR THE DISTRICT OF COLUMBIA CIRCUIT

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; AMERICAN PETROLEUM INSTITUTE, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, Administrator, U.S. EPA, Respondents.	Case No. 23-1193

DECLARATION OF DANIKA YEAGER IN SUPPORT OF INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA'S MOTION FOR STAY

I, Danika Yeager, declare that the following is true and correct:

1. I am over the age of twenty-one years old and have personal knowledge of the statements made herein.

2. I am Senior Vice-President of Operations, Projects, Technical and Operational Services, U.S. Natural Gas Pipelines at TC Energy, which is a member of the Interstate Natural Gas Association of America ("INGAA").

3. As the owner and operator of numerous reciprocating internal combustion engines used to support pipeline compressor and storage facilities rated at 1,000 horsepower or more ("pipeline engines"), TC Energy is directly regulated by the Final Rule being challenged, Federal "Good Neighbor Plan" for the 2015 Ozone

National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) ("Final Rule").

4. I joined TC Energy in September 2022 after holding executive positions at multiple midstream operator companies, and I possess over 25 years of combined midstream experience spanning operations; health, safety and environment; regulatory compliance; and commercial roles. I earned a Bachelor of Arts from Mary Washington College in Virginia, a Master of Science from the University of South Carolina, and a Master of Business Administration from Richmond College in London, England. In my current role, I am responsible for the operation and maintenance of TC Energy's U.S. natural gas pipeline system, which includes 32,000 miles of primarily interstate natural gas transmission pipeline, as well as the design and construction of new facilities associated with those assets.
5. Part of my responsibilities include helping TC Energy prepare to comply with the Final Rule. This declaration is based on my personal knowledge of facts and information related to TC Energy's business and strategy for compliance with the Final Rule, as well as my discussions with direct reports and the company's environmental and engineering staff.
6. I am providing this declaration in support of INGAA's motion to stay the Final Rule. The Final Rule will become effective on August 4, 2023, and it requires

that pipeline engines with a maximum rated capacity of 1,000 horsepower or more within 20 states[1] comply with certain emission limitations by the beginning of the 2026 ozone season on May 1, 2026, only 31 months from the effective date. 88 Fed. Reg. at 36,654, 36,820.

7. In recent months, numerous Circuit Courts have granted stays pending judicial review of EPA's decisions that disapprove certain Good Neighbor State Implementation Plans. These Good Neighbor "SIPs" provide a necessary predicate for the Final Rule. EPA has since promulgated an interim final rule preventing the federal plan from taking effect in some of the States where courts have stayed EPA's disapproval of the state plan: Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas. *See* Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP disapproval Action for Certain States, https://rb.gy/z6wfb (prepublication interim final rule signed June 30, 2023). EPA has not yet responded to stays issued for several additional states.

8. As discussed in more detail below, the Final Rule, if not stayed by the Court, will cause immediate and irreparable harm to TC Energy and the public. TC Energy estimates that 303 of the engines it owns and operates are subject to the Final

[1] Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

Rule—10% of all the pipeline engines that EPA estimated. 88 Fed. Reg. at 36,842. Of these 303 engines, 280 engines will likely require retrofitting with controls to comply with the Final Rule.[2]

9. Bringing all 280 units into compliance is expected to be an incredible effort that we anticipate will cost TC Energy **approximately $600 million, up to $75 million of which TC Energy must spend in the next 12 to 18 months.** [3] These estimates do not account for the supply chain challenges and market constraints for necessary expert services as a result of the tight compliance deadlines for retrofitting an exorbitant number of existing engines that will likely increase costs, disrupt service, and compound compliance risk due to resource availability.

10. Compounding these astronomical costs is the Final Rule's unreasonable timetable for compliance. EPA states that industry must start now to meet the compliance deadline: The Final Rule directs "source owners and operators that they should begin engineering and financial planning . . . to be prepared to meet this implementation timetable." 88 Fed. Reg. at 36,755. As outlined in this

[2] 82 of these are located in states where the rule will not immediately take effect due to judicial stays.

[3] In its comments on EPA's proposed rule, TC Energy stated that it operates 360 reciprocating internal combustion engines in sixteen affected states that exceed the proposed rule's applicability threshold. Of those, TC Energy estimated that 260 engines would require retrofitting at a cost of approximately $900 million. Since that time, TC Energy has revised its estimates based on changes in the Final Rule and further discussion with vendors.

declaration, although TC Energy has begun planning, design, and other pre-installation work to attempt to meet EPA's emission limits by the compliance deadline of May 1, 2026, TC Energy cannot realistically complete retrofitting all 280 engines in less than three years.

11. If not stayed by the Court, the Final Rule will also cause significant disruptions that pose significant harms to the public. Citizens and businesses rely on companies like TC Energy to provide the natural gas they need to heat their homes, cook their food, and run their businesses. That is why the Federal Energy Regulatory Commission ("FERC") regulates capacity: to ensure that citizens are not left without heat in January, for example, and to minimize their vulnerability to the price spikes that accompany severe shortages of natural gas. Put simply, the country cannot afford disruption on this scale—particularly at a time when energy prices are rising dramatically, and when energy security is more important than ever.

TC Energy's Operations and Final Rule Applicability

12. Through its pipeline subsidiaries, TC Energy operates 57,900 miles of natural gas pipelines and 653 billion cubic feet of storage capacity in North America. TC Energy transports approximately 25% of North America's natural gas to market and continues to build significant natural gas transportation infrastructure to connect new gas supplies to various consuming markets. TC Energy has 303

Final Rule-impacted reciprocating internal combustion engines ("RICE") in 14 of the 20 regulated states.

13. TC Energy owns 303 RICE with a capacity of 1,000 horsepower or more in the States of Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, New York, Ohio, Oklahoma, Pennsylvania, Texas, Virginia, and West Virginia that are subject to the Final Rule. TC Energy estimate that 280 of its engines will require controls to be retrofitted to achieve compliance with the Final Rule.

14. Natural gas-fired RICE allows TC Energy to serve energy markets nationwide and provide natural gas for public use. These engines are used at compressor stations along TC Energy's natural gas transmission pipelines to compress the natural gas that it transports. Compressing the natural gas increases its pressure, enabling the gas to flow along the pipeline system.

Costs of Compliance with Final Rule on TC Energy While the Court is Considering INGAA's Challenge

15. Pipeline engines are large, complex pieces of equipment and retrofitting them involves significant capital costs. Based on our estimates, discussions with contractors, and/or contractor quotes, retrofitting a single pipeline engine with the emission controls required by the Final Rule will range between $585,000 and $6.8 million depending on the engine type, its size, and current configuration. In total, TC Energy has calculated that it will cost approximately $600 million to install controls at *all* of TC Energy's 280 regulated engines. However, as

discussed further below, the Final Rule's compliance deadline of May 1, 2026, to implement all the mandated controls is unreasonable and likely unachievable.

16. Because of this aggressive deadline, TC Energy has already begun planning, design and other pre-installation work for all of its affected engines. Retrofitting emission controls involves long lead times to accommodate a multi-step process that includes identifying and analyzing which engines require controls to comply; designing, engineering, and procuring equipment; identifying and selecting a specialized contractor to install and test the equipment; preparing and submitting applications to modify existing permits and obtaining final permits; and finally, installation and testing.

17. The necessary permit modifications will require TC Energy's staff to spend a significant amount of time assembling the information and supporting documentation needed to apply for the necessary permit modifications and to coordinate with state permitting authorities as they process those applications. This typically includes conference calls with state permitting staff, responding to requests for additional information, revisions to the permit application as requested by state reviewers, and meetings with internal staff and third-party consultants. EPA estimates that the necessary permit modifications will take 6 to 12 months, but in TC Energy's experience, the timeline to receive a new permit

or complete major modifications to an existing permit is approximately 24 months or more.

18. Another key part of this multi-step process involves designing and engineering emission controls specific to each engine make and model. This requires TC Energy to retain specialized OEM primary combustion control vendors, of which there are few with the necessary experience in designing and installing controls on reciprocating internal combustion pipeline engines. Because these specialized contractors have limited capacity and are already seeing significant increases in demand for their services due to the Final Rule, TC Energy does not expect to be able to complete all the necessary engine retrofits in less than three years.

19. While TC Energy is diligently working with two of these specialized contractors to develop work scopes and budgets for specific unit makes and models, these vendors have indicated that current production and support levels allow only for the completion of approximately 25 units per year from each vendor across the industry. Additional manpower, training, and parts manufacturing to provide the ability to support the industry is only in preliminary stages. Each project from development to commissioning is expected to take 1yr+ for completion. Assuming these vendors can provide staffing dedicated to TC Energy and that current parts production does not diminish, TC Energy anticipates that, at most, it may be able to retrofit no more than 50 engines by the end of 2025.

20. Assuming it is realistically able to conduct as many as 25 retrofits per year, TC Energy expects it would spend up to $75 million in the next 12 to 18 months. TC Energy will likely prioritize completing retrofits of engines not located within a state subject to a judicial stay of its underlying "Good Neighbor SIP," but TC Energy's cost estimate necessarily includes costs related to planning, design, and other pre-installation work for all its pipeline engines requiring retrofits.

Impacts on Reliability of Nation's Natural Gas System Due to Compliance with Final Rule

21. Absent a stay pending judicial review, the Final Rule will have significant impacts on the reliability of the nation's natural gas system. The pipeline engines regulated by the Final Rule are vital to TC Energy's operation of its interstate transmission infrastructure, distributing natural gas to residential, commercial, and industrial users. Citizens and businesses rely on companies like TC Energy to provide the natural gas they need to heat their homes, cook their food, and run their businesses. Consequently, FERC requires interstate pipelines to be able to provide maximum capacity at all times to ensure that citizens are not left without heat in January, and to minimize their vulnerability to the price spikes that accompany severe shortages of natural gas.

22. While the Court is considering INGAA's challenge to the Final Rule, TC Energy will have to begin taking its engines off-line to start emission control installation without the backup capacity needed to meet FERC's requirements. Emission

control installation could take between 12 and 13 months per unit. This means that, over the next 12 to 18 months, TC Energy must shut down pipeline engines for several months at a time, even during the peak summer and winter seasons, threatening the interruption of natural gas services. This threat is significant because every other company subject to the Final Rule will also be attempting to design, procure, and install controls on their pipeline engines at the same time. With pipeline engines for multiple companies being off-line at the same time, the options for temporarily re-routing the flow of natural gas from customers to end users will likely be severely limited and threaten overall system reliability.

23. Further, failure to meet fully its FERC obligations to its customers could entail significant financial harm to TC Energy, because FERC rules require TC Energy to provide its shippers with "reservation charge credits" to refund what the shipper paid to reserve pipeline capacity, with limited exceptions. EPA's Regulatory Impact Analysis did not consider this potential impact.

24. To ensure reliable transportation of natural gas, TC Energy has a General Plant Maintenance Capital program that is established and funded 24 months in advance of project execution. With the timing of the Final Rule, TC Energy's 2024 and 2025 capital programs have already been established. This means that beginning compliance with the Final Rule now will cause funds earmarked for critical capital maintenance projects to be diverted.

Alternative Compliance Pathways in the Final Rule Do Not Eliminate the Harm to TC Energy

25. The Final Rule includes two possible compliance alternatives: case-by-case emissions rates and facility-wide averaging plans. 88 Fed. Reg. at 36,818, 36,820. Neither fully resolves TC Energy's concerns. The first alternative is a case-by-case exemption that would allow EPA to approve, at the agency's sole discretion, unit-specific emissions rates. TC Energy has determined that it may be appropriate to apply for such unit-specific rates for only a few of its pipeline engines subject to the Final Rule. Thus, this provision does not eliminate the enormous costs imposed on TC Energy to attain compliance for the majority of its affected engines.

26. All case-by-case requests must be submitted to EPA no later than August 5, 2024. Each request requires expansive technical, emissions profiling, and cost analysis that would require extensive internal staff time and support by third-party consultants, and assembling such applications would reduce resources TC Energy has available to work toward compliance for other engines. In addition, EPA requires a showing of "extreme economic hardship" to approve a request for a unit-specific emission rate, a term that EPA has not defined (either in narrative or with a cost-per-ton value). Moreover, EPA has also not offered any anticipated timeline by which applications for individual unit-specific exemptions would be processed. Thus—to the extent TC Energy avails itself of

this alternative compliance option for some of its pipeline engines—there is no guarantee of relief in a timely fashion even for those units.

27. Additionally, TC Energy has conducted a detailed review of the facility-wide averaging option in the Final Rule and determined that it cannot be used to reduce the number of units requiring control. The Final Rule only allows "any owner or operator of an affected unit to *propose* a Facility-Wide Averaging Plan that would, *if approved by EPA*, provide an alternative means for compliance with the emissions limits in this final rule." 88 Fed. Reg. at 36,820 (emphases added). Even assuming TC Energy submitted proposed plans to attempt to utilize the facility-wide averaging alternative, it is unclear what criteria EPA will use to evaluate any proposed plans and therefore no way to know whether EPA would actually approve any proposed plan. Without any reasonable benefit from the facility-wide averaging option or assurance of EPA acting on or even approving a plan in a timely manner, we must proceed to plan to design/engineer/procure controls accordingly. Therefore, TC Energy will need to install emission controls on practically all its impacted pipeline engines to comply with the Final Rule.

EPA's Discretionary and Limited Timeline Extensions Do Not Address TC Energy's Concerns

28. The Final Rule provides for case-by-case deadline extensions, but this does not lessen TC Energy's concerns about the feasibility of compliance by May 1, 2026, or that unless stayed by the Court, the Final Rule will require TC Energy to spend

up to $75 million while INGAA's challenge to the rule is pending. As stated above, due to vendor constraints, TC Energy expects it will—at most—be able to bring no more than 50 engines into compliance by the end of 2025. That means TC Energy would need to apply for a discretionary timeline extension for approximately 230 other engines, and some retrofits could extend even beyond the discretionary timeline extensions to be considered by EPA.

29. Because the timeline extension is discretionary, TC Energy cannot delay its preparations for compliance with the Final Rule based on an assumption that EPA will grant an extension. And because the Final Rule says that even to be considered for an extension, TC Energy must "take[] all steps possible to install controls for compliance with the applicable requirements," TC Energy must take action now to install emissions controls during the time the appeal is pending in this case. 88 Fed. Reg. at 36,760.

30. Finally, the extension process further restricts the compliance timeline because owner or operator must submit the request to EPA at least 180 days before the May 1, 2026, deadline. 88 Fed. Reg. at 36,760. The owner or operator remains subject to the May 1, 2026, deadline until the compliance extension is granted. Even will all reasonable diligence, there is no guarantee that EPA would grant the requested extensions or do so in enough time for TC Energy to make other

plans. As EPA states, "A denial will be effective on the date of denial." 88 Fed. Reg. at 36,760.

The Final Rule's Enormous Costs of Compliance are Not Automatically Recoverable, or Not Recoverable at All

31. Without a stay, should the Court later invalidate the Final Rule, TC Energy will have wasted enormous resources attempting to comply with the Final Rule's emission limitations while also potentially disrupting natural gas service nationwide. To the best of my knowledge, the pollution controls that will need to be installed to comply with the Final Rule are not required for compliance with any other federal or state regulation and there is no mechanism to recover the costs of these pollution controls from EPA or any federal entity.

32. The costs of adding controls to comply with the Final Rule are not automatically recoverable from TC Energy's customers, which pay based on fixed rates approved by FERC. If FERC were to approve a change to a rate sometime in the future, which is a lengthy and resource-intensive process, that new rate is applied prospectively and not retroactively to the time-period when the costs were incurred.

33. TC Energy would also be unable to recover costs from its vendors. Assuming vendors can provide staffing for even a portion of the necessary retrofitting projects, TC Energy will be required to pay vendor deposits months in advance of undertaking each project to secure a vendor's services. TC Energy will also

be required to make incremental payments to each vendor for the design and execution of each project. Absent a stay, TC Energy must incur these costs to attempt compliance by the Rule's deadline and will not be able to recover these costs from its vendors.

34. If the Court holds the Final Rule unlawful, TC Energy's expenditures to comply with the Final Rule will have been wasted on engine modifications that are unnecessary to meet TC Energy's customer demands. And once implemented, emission controls do not enhance the economic value of engines.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed in Houston, Texas on this 27th day of July, 2023.

SVP USNG

Danika Yeager

TECHNICAL MEMORANDUM

TO: Docket for Rulemaking, "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards" (EPA-HQ-OAR-2021-0668)
DATE: February 28, 2022
SUBJECT: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026

Note: EPA originally posted this document on March 11, 2022. This document, posted on March 29, 2022, corrects inadvertent errors referencing a filename on page 9 and in Table 5 on page 16.

I. Introduction

The EPA developed an analytical framework to facilitate decisions about industries, emissions unit types, and cost thresholds for including emissions units in the non-electric generating unit "sector" (non-EGUs) in a federal implementation plan (FIP) proposal for the 2015 ozone national ambient air quality standards (NAAQS) transport obligations. Using this analytical framework, we prepared a screening assessment for the year 2026.

This memorandum presents the analytical framework and summarizes the screening assessment the EPA prepared to identify industries and emissions unit types to include in proposed rules to obtain NOx emissions reductions from non-EGUs. Sections VII.A.2. and VII.C. of the proposal preamble include discussions of the non-EGU NOx emissions limits, compliance timing, and other related-rule requirements for the industries and emissions unit types identified through the screening assessment.

The remainder of this memorandum includes the following sections:

- II. Background on Analytical Framework
- III. The Analytical Framework
  - o Step 1 -- Identifying Potentially Impactful Industries in 2023
  - o Step 2a -- Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023
  - o Step 2b -- Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023
  - o Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023
- IV. Modifying the Analytical Framework for the Screening Assessment for 2026
- V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries
- VI. Request for Comment and Additional Information

II. Background on Analytical Framework

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the non-EGU "sector"[1] makes it challenging to define a single method to identify impactful emissions reductions. We incorporated air quality information as a first step in the analytical framework to help determine potentially impactful industries to focus on for further assessing emission reduction potential, air quality improvements, and costs. Given the lengthy decision-making and analysis schedules for the FIP

[1] The non-EGU "sector" includes non-electric generating emissions units in various manufacturing industries and does not include municipal waste combustors (MWC), cogeneration units, or <25 MW EGUs. For a discussion of MWCs, cogeneration units, and EGUs <25 MW, see Section VI.B.3. of the proposed rule preamble.

proposal, we developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update (RCU) for 2023[2], as well as the projected 2023 annual emissions inventory from the 2016v2 emissions platform that was used for the air quality modeling for the proposed rule.

Using the RCU modeling for 2023, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, which is 0.7 ppb (1% of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 NAAQS: AL, AR, CA, DE, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TN, TX, UT, VA, WI, WV, and WY.

To analyze non-EGU emissions units, we aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS.[3] Then for the linked states, we followed the 2-step process below:

1. **Step 1** -- We identified industries whose potentially controllable emissions are estimated, by applying the analytical framework, to have the greatest ppb impact on downwind air quality, [4] and
2. **Step 2** – We 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 we determined using underlying control device efficiency and cost information.

Additional details on these steps are presented in the Section III below.

Finally, the EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD,[5] that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season.[6] As such, we modified the analytical framework slightly and applied it for a screening assessment estimating potential emissions reductions, air quality improvements, and costs for the year 2026.

III. The Analytical Framework

Step 1 - Identifying Potentially Impactful Industries in 2023

The analytical framework starts with identifying industries whose potentially controllable emissions may contribute to downwind receptors. To identify industries that have large, meaningful air quality impacts from potentially controllable emissions, we estimated air quality contribution by 4-digit NAICS-based industry for 2023. To estimate the contributions by 4-digit NAICS at each downwind receptor, we used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[7]

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[2] We used the RCU air quality modeling for this screening assessment because the air quality modeling for the proposed rule was not completed in time to support this assessment.

[3] North American Industry Classification System (https://www.census.gov/naics/).

[4] To identify industries, we reviewed emissions units with >= 100tpy emissions units in the 2023 inventory in those industries in the upwind states.

[5] 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*.

[6] Note that information on control installation timing as detailed in the 2016 CSAPR Update Non-EGU TSD is not complete or sufficient to serve as a foundation for timing estimates for this proposed FIP.

[7] The calibration factors are receptor-specific factors. For the RCU, 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

We focused on assessing emissions units that emit >100 tpy of NOx.[8] By limiting the focus to potentially controllable emissions, well-controlled sources that still emit > 100 tpy are excluded from consideration. 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.

Based on the industry contribution data, we prepared a summary of the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions >= 0.01 ppb from each industry. We evaluated this information to identify breakpoints in the data, as described in detail in Appendix A. These breakpoints were then used to identify the most impactful industries to focus on for the next steps in the analysis.[9]

A review of the contribution data indicated that we should focus the assessment of NOx reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of >0.10 ppb and (2) contribute >= 0.01 ppb to at least 10 receptors. We refer to these four industries identified below as comprising **"Tier 1"**.

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

In addition, the contribution data suggests that we should include five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors. We refer to these five industries identified below as comprising **"Tier 2"**.

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

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.

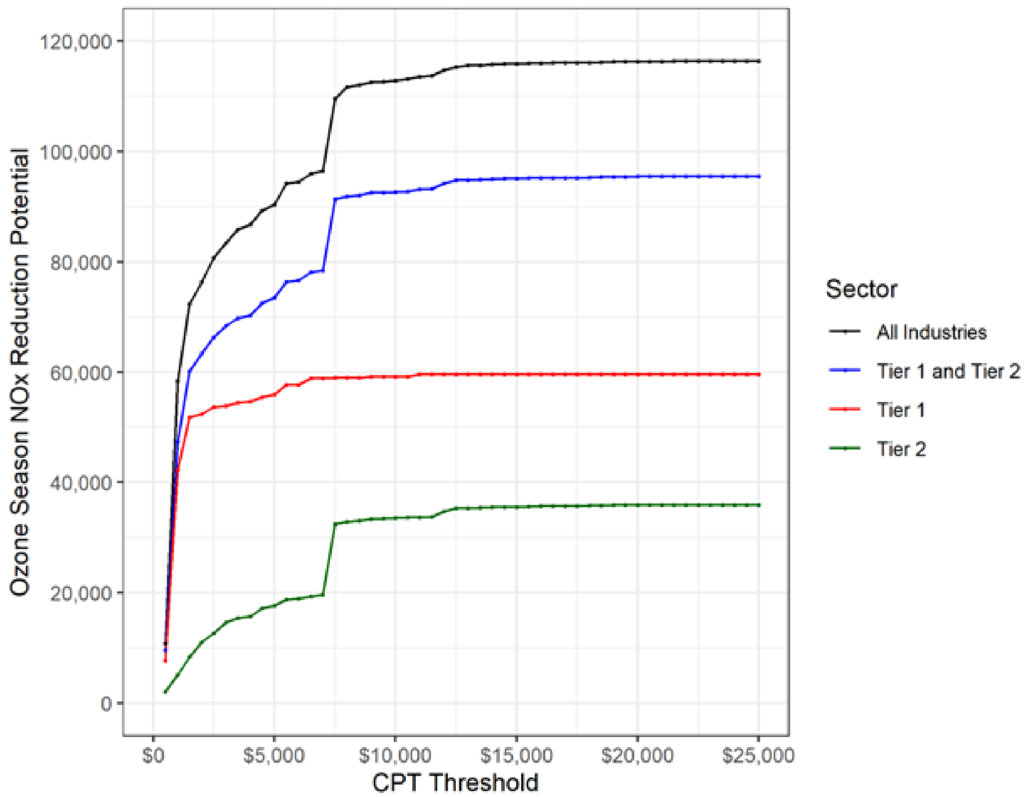
[8] In the non-EGU emission reduction assessment prepared for the Revised Cross State Air Pollution Rule Update (https://www.regulations.gov/document/EPA-HQ-OAR-2020-0272-0014), we reviewed emissions units with >150 tpy of NOx emissions. In this screening assessment, we broadened the scope to include emissions units with >=100 tpy of NOx emissions. We believe that emissions units that are smaller may already be controlled and reductions from these smaller units are likely to be more costly.

[9] The air quality contribution data and the R code that processed these data are available upon request.

Step 2a - Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023

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)[10], the Control Measures Database (CMDB)[11], 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 this data, we plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 indicates there is a "knee in the curve" at approximately $7,500 per ton.[12] We used this marginal cost threshold to further assess 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. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



[10] 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.
[11] The CMDB is available at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[12] The CoST run results, the CMDB, and the R code that generated the curves are available upon request.

Step 2b - Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023

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 emission reduction algorithm[13,14] with known controls.[15] We identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. Note that $7,500 per ton represents a marginal cost, and controls and related emissions reductions are available at several estimated costs up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

We then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 following the steps below.

1. We binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.
2. We used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the AQAT for control analyses in 2023. We multiplied the estimated non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.[16]

Note that we did not include the impact of reductions in the "home state" even if the "home state" was linked to receptor(s) in another state. That is, we only looked at the impact of NOx emissions reductions from upwind states. Furthermore, for each receptor we included impacts from states that are upwind to any receptor, not just those states that are upwind to that particular receptor.

Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023

In 2023 because boilers represent the majority emissions unit in the Tier 2 industries for which there were controls that cost up to $7,500 per ton (see Table 1 below), we targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers.

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[13] The maximum emission 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: https://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.
[14] The maximum emission reduction CoST run results and CMDB are available upon request.
[15] *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.
[16] The 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in AQAT for control analyses in 2023, the R code that processed the CoST run results using the maximum emission reduction algorithm, and the summaries of the air quality improvements are available upon request.

Table 1. Number of Emissions Unit Types in Tier 2 Industries

	Number of Emissions Units by Type		
Tier 2 Industries	**Boiler**	**Internal Combustion Engine**	**Industrial Processes**
Metal Ore Mining	--	1	15
Pulp, Paper, and Paperboard Mills	49	1	--
Petroleum and Coal Products Manufacturing	37	4	48
Basic Chemical Manufacturing	46	8	13
Lime and Gypsum Product Manufacturing	--	--	1
Totals	**132**	**14**	**77**

To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states we identified a universe of boilers with >100 tpy NOx emissions that had any contributions at downwind receptors.[17,18] We 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.[19,20]

- Criterion 1 -- Estimated maximum air quality contribution at an individual receptor of >=0.0025 ppb ***or*** estimated total contribution across downwind receptors of >=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 >=0.001 ppb.

IV. Modifying the Analytical Framework for the Screening Assessment for 2026

EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD, that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season. As such, we prepared a screening assessment for the year 2026 by generally applying the analytical framework detailed above. Specifically, we

- 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, and
- Updated the air quality modeling data by using data for 2026.

Using the projected 2023 emissions inventory introduced challenges associated with the application of new source performance standards (NSPS).[21] Some of the projected emissions inventory records reflected percent

[17] We used the 2023fj non-EGU point source inventory files from the 2016v2 emissions platform.

[18] MD, MO, NV, and WY did not have boilers with >100 tpy NOx emissions.

[19] 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 RCU ppb/ton values and the RCU calibration factors used in AQAT. The results are intended to provide a general indication of the relative impact across sources.

[20] For the impactful boiler assessment, the 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in the AQAT for ozone for control analyses in 2023, and the R code that processed the CoST run results are available upon request.

[21] Using the projected inventory also introduced challenges associated with the growth of emissions at sources over time. EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-

reductions associated with the application of current NSPS (e.g., Reciprocating Internal Combustion Engine, Natural Gas Turbines, Process Heaters NSPS). Applying NSPSs during the emissions projections process includes estimating the number of modifications/replacements that would trigger NSPS requirements. None of the existing sources, as they currently exist, would install a control because of a NSPS. But some of those sources might modify and become subject to the NSPS. Because we do not know which sources might become subject to an NSPS by modifying, across-the-board percent reductions from unknown control measures are applied to all of the sources.[22] As a result, CoST replaced some of the unknown control measures with a control measure that it concluded was more efficient. However, we do not know if a control would be applied to a particular source in response to the NSPS rules and if so, what that control would be. Therefore, we do not know if CoST is correctly replacing those unknown control measures. To address this challenge, we used a current, not projected, emissions inventory along with the latest air quality modeling information for 2026. Specifically, we used the 2019 inventory for information on emissions, emissions units, and estimated emissions reductions in concert with the emissions sector-specific (non-EGU-specific) ppb/ton factors for 2026 and 2026 AQAT calibration factors to estimate the impacts on future air quality from reductions at emissions units as those units currently exist.[23]

V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries

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. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however, CoST was 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 emission 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.

See Sections VII.A.2. and VII.C. of the proposal preamble for discussions of the NOx emissions limits, compliance timing, and other related rule requirements for the industries and emissions unit types identified through this screening assessment.

To prepare the screening assessment for 2026, we applied the analytical framework detailed in the sections above with the modifications discussed in the previous section. The assessment includes emissions units from the Tier 1 industries and impactful boilers from the Tier 2 industries. Using the latest air quality modeling for 2026, we 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 NAAQS: AR, CA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TX, UT, VA, WI, WV, and WY.
We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the

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term emissions reductions. For additional discussion of the 2019 inventory, please see the *2019 National Emissions Inventory Technical Support Document: Point Data Category* available in the docket. In switching to the 2019 inventory, however, we did not account for any growth or decrease in emissions that might occur at individual units. Because the controls applied by CoST have efficiencies, or percent reductions, this means we could be over- or under-estimating the emission reductions and their ppb impacts.

[22] For additional information on the 2016v2 inventory and the projected 2023 emissions inventory, please see the September 2021 *Technical Support Document Preparation of Emissions Inventories for 2016v2 North American Emissions Modeling Platform* in the docket or available at the following link: https://www.epa.gov/system/files/documents/2021-09/2016v2_emismod_tsd_september2021.pdf.

[23] For this proposed FIP, the EPA used the ozone AQAT, which is described in detail in *Ozone Policy Analysis Proposed Rule TSD* in the docket. The receptor-state specific calibration factors for 2026 were derived using the following air quality modeling runs: 2026 base case and 2026 control case with 30 percent across-the-board NOx emissions cuts.

existing control. We 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, we removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut down by 2026. See Appendix B for a summary of the facilities removed.

For the emissions units in the Tier 1 industries and the impactful boilers in the Tier 2 industries, the estimated emissions reductions, air quality improvements, and costs are summarized below and in Tables 2 through 5 that follow. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.[24] As shown in Table 2, the total estimated ozone season emissions reductions are 47,186 tons, the estimated total ppb improvement across all downwind receptors is 5.16 ppb, and the estimated total cost is $410.8 million annually. The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

Table 3 presents estimated ppb improvements at receptors grouped by region. For the coastal Connecticut/New York City nonattainment area receptors, total ppb improvements from Tier 1 and Tier 2 range from 0.247 to 0.356 ppb; for the receptors near Chicago, total ppb improvements range from 0.261 to 0.375 ppb; for the receptors along the western shoreline of Lake Michigan in Wisconsin, total ppb improvements range from 0.360 to 0.443 ppb; for the Houston receptors, total ppb improvements range from 0.284 to 0.472 ppb; and for the western receptors, ppb improvements range from <0.001 to 0.056 ppb. There are far fewer emissions reductions from western states because there are far fewer states and impacted emissions units in the west, and the resulting air quality improvements are noticeably lower.

For Tier 1 industries and the impactful boilers in the Tier 2 industries, Table 4 provides by state and by industry estimated emissions reductions and costs; Table 4a provides by state, estimated emissions reductions and costs. New Jersey and Nevada are not included in these tables because they did not have any estimated non-EGU reductions from the Tier 1 industries and boilers in Tier 2 industries that cost up to $7,500 per ton. In addition, Figure 2 shows the geographical distribution of ozone season reductions.

Table 5 provides by industry and east/west, the number and type of emissions units, total estimated emissions reductions, total ppb improvements, and costs. There are 489 emissions units contributing to the total estimated reductions of 47,186 ozone season tons and total estimated ppb improvements of 5.16 ppb.[25]

Table 6 includes by industry, the emissions source group, control technology, number of emissions units, ozone season emissions reductions, and annual total cost for the emissions units in the screening assessment. Lastly, Tables 7, 8, and 9 provide summaries of estimated ozone season emissions reductions, annual total cost, and average cost per ton by the control technologies CoST applied (i) across all non-EGU emissions units, (ii) across non-EGU emissions units grouped by the Tier 1 industries and impactful boilers in Tier 2 industries, and (iii) across non-EGU emissions units grouped by the seven individual Tier 1 and 2 industries.

[24] EPA submitted an information collection request (ICR) to OMB associated with the proposed monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Proposed Rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units*, EPA ICR No. 2705.01. The ICR is summarized in Section XI.B.2 of the proposed rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately $11.45 million per year for the first three years. These costs are not reflected in the cost estimates presented in Tables 2 through 9.

[25] While the number of units listed in Table 5 sums to 491, the emissions inventory records for two of the units in Tier 1 industries include SCCs for both boilers and industrial processes. As a result, those units appear twice in the counts.

For the Excel workbooks with Tables 2 through 9, see *Transport Proposal – NonEGU Results – 03-16-2022.xlsx* and *Non-EGU Analysis Controls – 11-15-2021.xlsx* in the docket.[26]

[26] The R code that processed the CoST run results, the sector-specific (non-EGU-specific) ppb/ton values, and the 2026 AQAT calibration factors used to prepare these tables are available upon request.

All costs are in 2016$ and do not include monitoring, recordkeeping, reporting, or testing costs.

Table 2. Estimated Emissions Reductions (ozone season tons), Maximum PPB Improvements, and Costs

Option	Ozone Season Emissions Reductions (East/West)	Total PPB Improvement Across All Downwind Receptors	Max PPB Improvement Across All Downwind Receptors	Annual Total Cost (million $) (Avg Annual Cost per 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	0.392	$356.6 ($3,610)	Cement and Concrete Product Manufacturing (47), Glass and Glass Product Manufacturing (44), Iron and Steel Mills and 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	0.169	$54.2 ($3,744)	Basic Chemical Manufacturing (17), Petroleum and Coal Products Manufacturing (10), Pulp, Paper, and Paperboard Mills (25)

The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

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Table 3. Estimated PPB Improvements at Receptors Grouped by Region*

Receptor ID	State	Receptor Name	Average/Max PPB Improvement Needed to Attain	Home State PPB Contribution	Tier 1	Tier 2	Total
90010017	CT	Greenwich	0.6/1.3	9.3	0.231	0.016	0.247
90013007	CT	Stratford	1.9/2.8	4.1	0.332	0.024	0.356
90019003	CT	Westport	3.7/3.9	2.9	0.314	0.022	0.336
90099002	CT	Madison	-/1.5	3.9	0.323	0.023	0.346
170310001	IL	Chicago/Alsip	-/1.6	19.4	0.196	0.065	0.261
170310032	IL	Chicago/South	-/0.8	16.6	0.299	0.076	0.375
170310076	IL	Chicago/ComEd	-/0.4	18.7	0.229	0.060	0.289
170314201	IL	Chicago/Northbrook	-/1.5	21.4	0.262	0.069	0.332
170317002	IL	Chicago/Evanston	-/1.1	18.9	0.307	0.049	0.356
550590019	WI	Kenosha/Water Tower	0.8/1.7	5.8	0.325	0.035	0.360
550590025	WI	Kenosha/Chiwaukee	-/0.2	2.6	0.392	0.051	0.443
551010020	WI	Racine/Racine	-/1.2	10.8	0.353	0.044	0.397
480391004	TX	Houston/Brazoria	-/0.3	29.3	0.302	0.169	0.472
482010024	TX	Houston/Aldine	3.3/4.8	29.7	0.186	0.098	0.284
40278011	AZ	Yuma	-/0.9	2.8	0.027	0.001	0.028
60070007	CA	Butte	-/-0.8	23.5	0.000	0.000	0.000
60170010	CA	El Dorado #1	4.1/6.5	26.7	0.000	0.000	0.000
60170020	CA	El Dorado #2	2.3/4.1	28.7	0.000	0.000	0.000
60190007	CA	Fresno #1	8.6/10.4	29.1	0.001	0.000	0.001
60190011	CA	Fresno #2	11/11.9	31.1	0.002	0.000	0.002
60195001	CA	Fresno #3	11.8/14.5	30.2	0.002	0.000	0.002
60570005	CA	Nevada	6.3/9.6	25.4	0.000	0.000	0.000
60610003	CA	Placer #1	5/7.7	29.8	0.000	0.000	0.000
60610004	CA	Placer #2	0/5.1	24	0.000	0.000	0.000
60670012	CA	Sacramento	2.7/3.4	30.8	0.000	0.000	0.000
60990005	CA	Stanislaus	3.8/4.7	29.2	0.001	0.000	0.001
80350004	CO	Denver/Chatfield	-/0.2	15.6	0.055	0.001	0.056
80590006	CO	Rocky Flats	0.8/1.4	17.3	0.042	0.000	0.042
80590011	CO	Denver/NREL	1.7/2.4	17.6	0.044	0.001	0.044
490110004	UT	SLC/Bountiful	0.8/3	8	0.037	0.002	0.038
490353006	UT	SLC/Hawthorne	1.6/3.2	8.3	0.036	0.002	0.038
490353013	UT	SLC/Herriman	2.6/3.1	8.9	0.018	0.001	0.019
490570002	UT	SLC/Ogden	-/0.8	6.1	0.034	0.001	0.035

**Home state emission reductions are not assumed in this analysis.*

Table 4. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State And By Industry, Estimated Emissions Reductions (ozone season tons*) and Costs

		Tier 1		Tier 2	
State	Industry	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	Basic Chemical Manufacturing	-	-	87	$1.1 ($5,113)
AR	Glass and Glass Product Manufacturing	47	$0.2 ($2,046)	-	-
AR	Iron and Steel Mills and Ferroalloy Manufacturing	6	$0.0 ($631)	-	-
AR	Pipeline Transportation of Natural Gas	868	$10.1 ($4,852)	-	-
AR	Pulp, Paper, and Paperboard Mills	-	-	646	$6.1 ($3,967)
CA	Cement and Concrete Product Manufacturing	1,162	$3.6 ($1,279)	-	-
CA	Glass and Glass Product Manufacturing	299	$0.9 ($1,293)	-	-
CA	Petroleum and Coal Products Manufacturing	-	-	68	$0.4 ($2,349)
CA	Pipeline Transportation of Natural Gas	137	$1.5 ($4,718)	-	-
IL	Cement and Concrete Product Manufacturing	234	$0.7 ($1,279)	-	-
IL	Glass and Glass Product Manufacturing	901	$2.6 ($1,180)	-	-
IL	Pipeline Transportation of Natural Gas	1,316	$13.7 ($4,348)	-	-
IN	Cement and Concrete Product Manufacturing	468	$1.4 ($1,279)	-	-
IN	Glass and Glass Product Manufacturing	338	$1.7 ($2,046)	-	-
IN	Iron and Steel Mills and Ferroalloy Manufacturing	1,829	$16.0 ($3,653)	-	-
IN	Petroleum and Coal Products Manufacturing	-	-	388	$2.8 ($2,989)
IN	Pipeline Transportation of Natural Gas	152	$2.0 ($5,457)	-	-
KY	Pipeline Transportation of Natural Gas	2,291	$28.7 ($5,213)	-	-
LA	Basic Chemical Manufacturing	-	-	1,611	$15.2 ($3,939)
LA	Glass and Glass Product Manufacturing	206	$1.9 ($3,770)	-	-
LA	Petroleum and Coal Products Manufacturing	-	-	477	$4.0 ($3,498)
LA	Pipeline Transportation of Natural Gas	3,915	$44.3 ($4,720)	-	-
LA	Pulp, Paper, and Paperboard Mills	-	-	561	$5.2 ($3,830)
MD	Pipeline Transportation of Natural Gas	45	$0.3 ($3,042)	-	-
MI	Cement and Concrete Product Manufacturing	371	$1.1 ($1,279)	-	-
MI	Glass and Glass Product Manufacturing	50	$0.3 ($2,661)	-	-
MI	Iron and Steel Mills and Ferroalloy Manufacturing	38	$0.4 ($4,194)	-	-
MI	Pipeline Transportation of Natural Gas	2,272	$25.9 ($4,747)	-	-
MN	Glass and Glass Product Manufacturing	115	$0.6 ($2,288)	-	-
MN	Pipeline Transportation of Natural Gas	558	$7.3 ($5,452)	-	-
MO	Cement and Concrete Product Manufacturing	1,296	$4.0 ($1,279)	-	-
MO	Glass and Glass Product Manufacturing	227	$1.1 ($1,992)	-	-
MO	Pipeline Transportation of Natural Gas	1,581	$20.2 ($5,338)	-	-
MS	Pipeline Transportation of Natural Gas	1,577	$19.0 ($5,009)	-	-
MS	Pulp, Paper, and Paperboard Mills	-	-	184	$1.4 ($3,243)
NY	Cement and Concrete Product Manufacturing	142	$0.4 ($1,279)	-	-
NY	Glass and Glass Product Manufacturing	141	$0.5 ($1,572)	-	-
NY	Pipeline Transportation of Natural Gas	106	$1.2 ($4,697)	-	-
NY	Pulp, Paper, and Paperboard Mills	-	-	111	$1.2 ($4,486)

OH	Cement and Concrete Product Manufacturing	116	$0.4 ($1,279)	-	-
OH	Glass and Glass Product Manufacturing	451	$2.2 ($1,998)	-	-
OH	Iron and Steel Mills and Ferroalloy Manufacturing	847	$7.6 ($3,763)	-	-
OH	Pipeline Transportation of Natural Gas	1,198	$14.6 ($5,062)	-	-
OH	Pulp, Paper, and Paperboard Mills	-	-	179	$2.3 ($5,303)
OK	Cement and Concrete Product Manufacturing	586	$1.8 ($1,279)	-	-
OK	Glass and Glass Product Manufacturing	190	$1.2 ($2,550)	-	-
OK	Pipeline Transportation of Natural Gas	2,799	$34.1 ($5,083)	-	-
PA	Cement and Concrete Product Manufacturing	888	$2.8 ($1,336)	-	-
PA	Glass and Glass Product Manufacturing	1,379	$3.8 ($1,133)	-	-
PA	Iron and Steel Mills and Ferroalloy Manufacturing	438	$6.1 ($5,823)	-	-
PA	Petroleum and Coal Products Manufacturing	-	-	98	$0.6 ($2,349)
PA	Pipeline Transportation of Natural Gas	427	$4.1 ($3,994)	-	-
PA	Pulp, Paper, and Paperboard Mills	-	-	54	$0.9 ($7,019)
TX	Cement and Concrete Product Manufacturing	1,234	$7.8 ($2,624)	-	-
TX	Glass and Glass Product Manufacturing	1,470	$3.9 ($1,109)	-	-
TX	Pipeline Transportation of Natural Gas	1,736	$20.7 ($4,966)	-	-
UT	Cement and Concrete Product Manufacturing	520	$1.6 ($1,279)	-	-
UT	Pipeline Transportation of Natural Gas	237	$2.7 ($4,718)	-	-
VA	Cement and Concrete Product Manufacturing	398	$1.2 ($1,279)	-	-
VA	Glass and Glass Product Manufacturing	174	$0.9 ($2,154)	-	-
VA	Iron and Steel Mills and Ferroalloy Manufacturing	92	$1.0 ($4,357)	-	-
VA	Pipeline Transportation of Natural Gas	801	$10.5 ($5,457)	-	-
VA	Pulp, Paper, and Paperboard Mills	-	-	98	$1.4 ($5,903)
WI	Glass and Glass Product Manufacturing	677	$2.5 ($1,517)	-	-
WI	Pulp, Paper, and Paperboard Mills	-	-	1,472	$11.7 ($3,307)
WV	Cement and Concrete Product Manufacturing	230	$0.7 ($1,279)	-	-
WV	Pipeline Transportation of Natural Gas	751	$6.5 ($3,612)	-	-
WY	Cement and Concrete Product Manufacturing	446	$1.4 ($1,279)	-	-
WY	Pipeline Transportation of Natural Gas	380	$4.9 ($5,349)	-	-
	Grand Total	**41,153**	**$356.6 ($3,610)**	**6,033**	**$54.2 ($3,744)**

*Ozone season tons are calculated as tpy from the NEI multiplied by 5/12.

Note that New Jersey and Nevada did not have any estimated non-EGU reductions that cost up to $7,500 per ton from the Tier 1 industries and boilers in Tier 2 industries.

Table 4a. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State, Estimated Emissions Reductions (ozone season tons) and Costs

	Tier 1		Tier 2	
State	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	922	$10.4 ($4,679)	732	$7.2 ($4,102)
CA	1,598	$6.0 ($1,576)	68	$0.4 ($2,349)
IL	2,452	$17.0 ($2,890)	-	-
IN	2,787	$21.1 ($3,157)	388	$2.8 ($2,989)
KY	2,291	$28.7 ($5,213)	-	-
LA	4,121	$46.2 ($4,673)	2,649	$24.4 ($3,837)
MD	45	$0.3 ($3,042)	-	-
MI	2,731	$27.7 ($4,230)	-	-
MN	673	$7.9 ($4,910)	-	-
MO	3,103	$25.3 ($3,399)	-	-
MS	1,577	$19.0 ($5,009)	184	$1.4 ($3,243)
NY	389	$2.2 ($2,316)	111	$1.2 ($4,486)
OH	2,611	$24.7 ($3,944)	179	$2.3 ($5,303)
OK	3,575	$37.1 ($4,325)	-	-
PA	3,132	$16.8 ($2,237)	152	$1.5 ($4,013)
TX	4,440	$32.4 ($3,038)	-	-
UT	757	$4.3 ($2,356)	-	-
VA	1,465	$13.6 ($3,861)	98	$1.4 ($5,903)
WI	677	$2.5 ($1,517)	1,472	$11.7 ($3,307)
WV	982	$7.2 ($3,065)	-	-
WY	826	$6.2 ($3,152)	-	-

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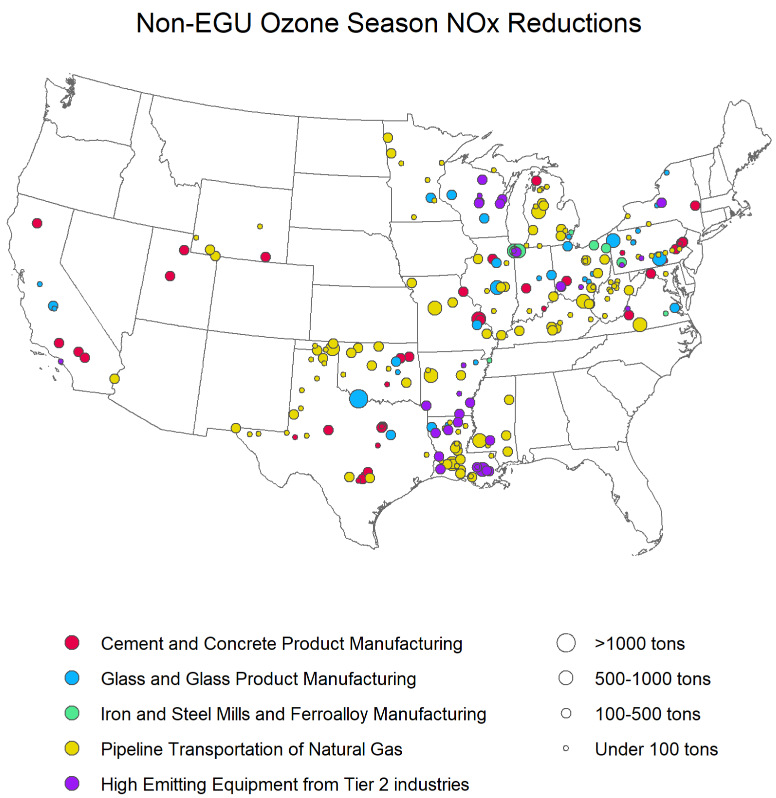
Figure 2. Geographical Distribution of Ozone Season NOx Reductions and Summary of Reductions by Industry and by State



State	Cement and Concrete Product Manufacturing	Glass and Glass Product Manufacturing	Iron and Steel Mills and Ferroalloy Manufacturing	Pipeline Transportation of Natural Gas	High Emitting Equipment from Tier 2 industries	Total
LA	0	206	0	3,915	2,649	6,769
TX	1,234	1,470	0	1,736	0	4,440
OK	586	190	0	2,799	0	3,575
PA	888	1,379	438	427	152	3,284
IN	468	338	1,829	152	388	3,175
MO	1,296	227	0	1,581	0	3,103
OH	116	451	847	1,198	179	2,790
MI	371	50	38	2,272	0	2,731
IL	234	901	0	1,316	0	2,452
KY	0	0	0	2,291	0	2,291
WI	0	677	0	0	1,472	2,150
MS	0	0	0	1,577	184	1,761
CA	1,162	299	0	137	68	1,666
AR	0	47	6	868	732	1,654
VA	398	174	92	801	98	1,563
WV	230	0	0	751	0	982
WY	446	0	0	380	0	826
UT	520	0	0	237	0	757
MN	0	115	0	558	0	673
NY	142	141	0	106	111	500
MD	0	0	0	45	0	45

Table 5. By Industry, Number and Type of Emissions Units, Total Estimated Emissions Reductions (ozone season tons), Total PPB Improvements, and Costs

		Number of Units by Type			Ozone Season Emissions Reductions (tons) by Type of Unit			Total PPB Improvement Across Downwind Receptors (Max Improvement At Receptor)		Annual Total Cost (million $) (Avg Annual Cost per Ton)
Industry	Region	Boilers	Internal Combustion Engines	Industrial Processes	Boilers	Internal Combustion Engines	Industrial Processes	East	West	
Glass and Glass Product Manufacturing	East	-	-	41	-	-	6,367	0.6962 (0.0865)	0.0015 (0.0004)	$23.2 ($1,520)
	West	-	-	3	-	-	299	0.0009 (0.0001)	0.0332 (0.0066)	$0.9 ($1,293)
Cement and Concrete Product Manufacturing	East	1	-	39	16	-	5,948	0.6382 (0.0707)	0.0018 (0.0006)	$22.4 ($1,566)
	West	-	-	8	-	-	2,128	0.0151 (0.0019)	0.1996 (0.0332)	$6.5 ($1,279)
Iron and Steel Mills and Ferroalloy Manufacturing	East	25	-	15	2,044	-	1,207	1.1556 (0.1750)	0.0000 (0.0000)	$31.2 ($3,995)
Pipeline Transportation of Natural Gas	East	-	296	-	-	22,390	-	1.5373 (0.2815)	0.0057 (0.0020)	$263.2 ($4,898)
	West	-	11	-	-	754	-	0.0086 (0.0010)	0.0586 (0.0170)	$9.1 ($5,037)
Basic Chemical Manufacturing	East	17	-	-	1,698	-	-	0.1655 (0.0107)	0.0002 (0.0000)	$16.3 ($3,999)
Petroleum and Coal Products Manufacturing	East	9	-	-	962	-	-	0.2677 (0.0258)	0.0000 (0.0000)	$7.3 ($3,176)
	West	1	-	-	68	-	-	0.0002 (0.0000)	0.0075 (0.0015)	$0.4 ($2,349)
Pulp, Paper, and Paperboard Mills	East	25	-	-	3,305	-	-	0.3678 (0.0117)	0.0002 (0.0000)	$30.2 ($3,807)

Blue highlights reflect western states information.

Orange highlights reflect Tier 2 industries with impactful boilers.

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Table 6. By Industry, Emissions Source Group, Control Technology, Number of Units, Estimated Emissions Reductions (ozone season tons), and Annual Total Cost

Industry	Emissions Source Group	Control Technology	Number of Units	Ozone Season Emissions Reductions	Annual Total Cost (million $)
Cement and Concrete Product Manufacturing	Boilers - < 10 Million BTU/hr; Industrial Processes - Kiln	Ultra Low NOx Burner; Selective Non-Catalytic Reduction	1	117	$0.5
	Industrial Processes - Kiln	Selective Non-Catalytic Reduction	24	3,123	$9.7
	Industrial Processes - Preheater Kiln	Selective Non-Catalytic Reduction	3	342	$1.2
	Industrial Processes - Preheater/Precalciner Kiln	Selective Non-Catalytic Reduction	19	4,510	$17.5
Glass and Glass Product Manufacturing	Industrial Processes - Container Glass: Melting Furnace	Selective Catalytic Reduction	27	1,676	$8.7
	Industrial Processes - Flat Glass: Melting Furnace	Selective Catalytic Reduction	13	4,674	$12.7
	Industrial Processes - Furnace: General	Oxygen Enriched Air Staging	1	52	$0.1
	Industrial Processes - Pressed and Blown Glass: Melting Furnace	Selective Catalytic Reduction	3	264	$2.7
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	3	383	$4.2
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	6	282	$2.2
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	106	$1.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	166	$1.0
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Ultra Low NOx Burner	6	360	$2.9
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Selective Catalytic Reduction; Ultra Low NOx Burner and Selective Catalytic Reduction	1	114	$1.7
	Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	65	$0.4
	Boilers - Blast Furnace Gas; Industrial Processes - Sintering: Windbox; Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation; Industrial Processes - Process Gas: Process Heaters	Ultra Low NOx Burner; Selective Catalytic Reduction; Low NOx Burner and Flue Gas Recirculation	1	440	$4.4
	Boilers - Coke Oven Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	394	$3.7
	Boilers - Coke Oven Gas; Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner; Ultra Low NOx Burner and Selective Catalytic Reduction	1	116	$1.6
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack	Selective Catalytic Reduction	2	185	$1.9
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack; Industrial Processes - General	Selective Catalytic Reduction; Low NOx Burner	1	172	$1.7
	Industrial Processes - Basic Oxygen Furnace (BOF): Top Blown Furnace: Primary	Selective Catalytic Reduction	1	50	$0.5
	Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation	Selective Catalytic Reduction	1	38	$0.4
	Industrial Processes - General	Low NOx Burner	5	191	$1.7
	Industrial Processes - General; Industrial Processes - Coke Oven or Blast Furnace	Low NOx Burner; Low NOx Burner and Flue Gas Recirculation	1	84	$1.0
	Industrial Processes - Other Not Classified	Low NOx Burner and Flue Gas Recirculation	2	43	$0.1
	Industrial Processes - Sintering: Windbox	Selective Catalytic Reduction	1	60	$0.6
Pipeline Transportation of Natural Gas	Internal Combustion Engines - 2-cycle Clean Burn	Layered Combustion	1	60	$0.8
	Internal Combustion Engines - 2-cycle Lean Burn	Layered Combustion	136	12,645	$165.6
	Internal Combustion Engines - 4-cycle Lean Burn	Selective Catalytic Reduction	41	2,656	$21.6
	Internal Combustion Engines - 4-cycle Rich Burn	Non-Selective Catalytic Reduction	2	147	$0.2
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion	94	6,329	$72.0
	Internal Combustion Engines - Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	12	193	$1.1
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion; Adjust Air to Fuel Ratio and Ignition Retard	1	49	$0.4
	Internal Combustion Engines - Turbine	Selective Catalytic Reduction and Steam Injection	17	929	$8.4
	Internal Combustion Engines - Turbine	SCR + DLN Combustion	3	136	$2.1

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Basic Chemical Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	6	786	$7.5
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	104	$1.5
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	1	133	$1.0
	Boilers - 10-100 Million BTU/hr	Selective Catalytic Reduction	1	43	$0.1
	Boilers - Cogeneration	Selective Catalytic Reduction	1	68	$0.9
	Boilers - Distillate Oil - Grades 1 and 2: Boiler	Selective Catalytic Reduction	1	47	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	293	$2.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	2	138	$0.8
	Boilers - Subbituminous Coal: Traveling Grate (Overfeed) Stoker	Selective Catalytic Reduction	1	87	$1.1
Petroleum and Coal Products Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	1	41	$0.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	38	$0.4
	Boilers - Boiler, >= 100 Million BTU/hr	Natural Gas Reburn	1	284	$1.8
	Boilers - Coke Oven Gas	Ultra Low NOx Burner	1	98	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	433	$3.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	3	137	$0.9
Pulp, Paper, and Paperboard Mills	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	5	618	$6.8
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	3	151	$1.0
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	1	68	$1.2
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner	2	106	$0.5
	Boilers - Bituminous Coal: Cyclone Furnace	Selective Catalytic Reduction	2	662	$3.4
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom	Ultra Low NOx Burner and Selective Catalytic Reduction	1	111	$1.1
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom; Boilers - > 100 Million BTU/hr	Low NOx Burner; Selective Catalytic Reduction	1	98	$1.4
	Boilers - Bituminous Coal: Spreader Stoker	Selective Catalytic Reduction	3	251	$3.2
	Boilers - Cogeneration	Ultra Low NOx Burner and Selective Catalytic Reduction	2	338	$2.9
	Boilers - Fluid Catalytic Cracking Unit with CO Boiler: Natural Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	289	$2.7
	Boilers - Subbituminous Coal: Boiler, Spreader Stoker	Selective Catalytic Reduction	2	348	$3.7
	Boilers - Subbituminous Coal: Spreader Stoker	Selective Catalytic Reduction	1	266	$2.3

Table 7. 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	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Layered Combustion	12,706	$166,398,282	$5,457
Low NOx Burner	231	$2,092,579	$3,773
Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Natural Gas Reburn	284	$1,843,948	$2,703
Non-Selective Catalytic Reduction	147	$205,808	$585
Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Oxygen Enriched Air Staging	52	$95,641	$764
SCR + DLN Combustion	136	$2,060,943	$6,301
Selective Catalytic Reduction	12,239	$74,692,132	$2,543
Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Ultra Low NOx Burner	1,670	$11,584,405	$2,890
Ultra Low NOx Burner and Selective Catalytic Reduction	3,946	$38,959,490	$4,114

Table 8. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Tier 1 Industries and Impactful Boilers in Tier 2 Industries

Tier	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Tier 1	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Tier 1	Layered Combustion	12,706	$166,398,282	$5,457
Tier 1	Low NOx Burner	211	$1,852,495	$3,656
Tier 1	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Tier 1	Non-Selective Catalytic Reduction	147	$205,808	$585
Tier 1	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Tier 1	Oxygen Enriched Air Staging	52	$95,641	$764
Tier 1	SCR + DLN Combustion	136	$2,060,943	$6,301
Tier 1	Selective Catalytic Reduction	10,219	$55,575,188	$2,266
Tier 1	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Tier 1	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Tier 1	Ultra Low NOx Burner	962	$7,172,778	$3,107
Tier 1	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Tier 2	Low NOx Burner	20	$240,084	$5,022
Tier 2	Natural Gas Reburn	284	$1,843,948	$2,703
Tier 2	Selective Catalytic Reduction	2,020	$19,116,944	$3,942
Tier 2	Ultra Low NOx Burner	708	$4,411,626	$2,594
Tier 2	Ultra Low NOx Burner and Selective Catalytic Reduction	3,000	$28,596,941	$3,972

Table 9. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Seven Individual Tier 1 and Tier 2 Industries

Industry	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Cement and Concrete Product Manufacturing	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Cement and Concrete Product Manufacturing	Ultra Low NOx Burner	16	$169,531	$4,410
Glass and Glass Product Manufacturing	Oxygen Enriched Air Staging	52	$95,641	$764
Glass and Glass Product Manufacturing	Selective Catalytic Reduction	6,615	$24,062,362	$1,516
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner	211	$1,852,495	$3,656
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Iron and Steel Mills and Ferroalloy Manufacturing	Selective Catalytic Reduction	948	$9,886,092	$4,345
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner	946	$7,003,247	$3,085
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Pipeline Transportation of Natural Gas	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Pipeline Transportation of Natural Gas	Layered Combustion	12,706	$166,398,282	$5,457
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction	147	$205,808	$585
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Pipeline Transportation of Natural Gas	SCR + DLN Combustion	136	$2,060,943	$6,301
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction	2,656	$21,626,734	$3,393
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Basic Chemical Manufacturing	Selective Catalytic Reduction	348	$4,198,768	$5,027
Basic Chemical Manufacturing	Ultra Low NOx Burner	138	$769,564	$2,317
Basic Chemical Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	1,211	$11,326,715	$3,896
Petroleum and Coal Products Manufacturing	Natural Gas Reburn	284	$1,843,948	$2,703
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner	313	$2,110,773	$2,808
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	433	$3,762,867	$3,624
Pulp, Paper, and Paperboard Mills	Low NOx Burner	20	$240,084	$5,022
Pulp, Paper, and Paperboard Mills	Selective Catalytic Reduction	1,672	$14,918,176	$3,717
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner	257	$1,531,289	$2,484
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner and Selective Catalytic Reduction	1,356	$13,507,360	$4,151

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VI. Request for Comment and Additional Information

In this screening assessment the EPA used CoST, the CMDB, and the 2019 emissions inventory to assess emission reduction potential from non-EGU emissions units in several industries. We 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 above, the cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

As discussed in Section VI.D.2.a of the proposal preamble, the EPA requests comment on the capital and annual costs of several potential control technologies, and in particular 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); the effectiveness of low emissions combustion in controlling NO_X from reciprocating IC engines, compared to other potential NO_X controls for these engines; and whether controls on ICI boilers and reciprocating IC engines are likely to be run all year or only during the ozone season.

The EPA also 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, the availability of vendors and materials, and the earliest possible installation times for SCR on glass furnaces; SNCR 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.

Finally, with respect to emissions monitoring requirements, the 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.

APPENDIX A – Analysis of Industry Contribution Data

This appendix describes the analyses performed to help focus the non-EGU analytical framework and resulting screening assessment on the most impactful industries.

To inform this analysis, first using the procedure described in Section III, Step 1 above, we estimated contributions from each of 41 industries to each nonattainment and maintenance receptor in 2023 and used these data to calculate the 5 metrics identified in Table A-1.[27,28] A summary of the data for each metric for each industry is provided in Table A-3. These metrics were selected to provide air quality information to inform an evaluation of the magnitude and geographic scope of contributions from individual industries. Metrics 1, 2, and 3 provide information on the magnitude of the contribution. Metric 4 provides information on the geographic scope of the downwind impact, whereas Metric 5 provides information on the geographic scope of upwind state contributions. Of the three air quality metrics we chose to analyze the data for Metric 2, the maximum contribution to any downwind receptor, because this metric aligns with the air quality metric used in Step 2 of the four-step interstate transport framework to identify linked upwind states for further review in Step 3 of the interstate transport framework. To examine the geographic breadth of the industry contributions we chose Metric 4 because that metric provides information on the extent of impacts on downwind air quality problems.

Table A-1. Contribution Metrics for Non-EGU Assessment

1	Total contribution to all downwind receptors
2	Maximum contribution to any downwind receptor
3	Average contribution across all receptors
4	Number of receptors with contributions >= 0.01 ppb
5	Number of linked upwind states with highest industry contribution >= 0.01 ppb

Next, we evaluated the maximum downwind contributions to identify the most impactful industries for further analysis. This approach included a semi-quantitative examination of rank-ordered maximum contributions to identify breakpoints in the data that might serve as an initial screen to eliminate non-impactful industries from further analysis of the contribution data. The distribution of maximum contributions provided in Table A-3 indicate that there is a large range in the values across the 41 industries. Specifically, 5 industries individually contribute more than 0.10 ppb, 3 industries contribute between 0.05 ppb and 0.10 ppb, 11 industries contribute between 0.01 and 0.05 ppb, 8 industries contribution between 0.005 and 0.01 ppb, and 14 industries contribute less than 0.005 ppb.

The rank-ordered maximum downwind contributions from individual industries are shown in Figure A-1. In this figure each point represents the maximum contribution to a downwind receptor from a particular industry. Note that the values for the highest contributing industries are not show in the figure in order to provide greater resolution of the shape of the distribution at the lower end of the values. The declining curve in Figure A-1 exhibits a shape similar to a harmonic distribution. Initially, there is a fairly steep drop in contributions with a breakpoint between roughly 0.04 and 0.06 ppb followed by a steady decline to 0.01 ppb. Beyond 0.01 ppb the shape of the distribution is much flatter. The data suggest that perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data. Based on the distribution

[27] Receptors in California were not considered in evaluating the impacts of non-EGU sources because EPA's contributions from upwind states to these receptors at Step 2 of the four-step interstate transport framework finds that these monitoring sites are overwhelmingly impacted by in-state emissions to a degree not comparable with any other identified nonattainment or maintenance-only receptors in the country. In this regard, EPA is proposing a determination that California receptors are not sufficiently impacted by interstate transport of ozone to warrant proceeding with a Step 3 evaluation of emissions reduction opportunities.
[28] The methods for identifying receptors are described in the Air Quality Modeling TSD for this proposed rule.

of the data we determined that 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the non-EGU contribution analysis. The specific industries with a maximum downwind contribution >= 0.01 ppb are identified in Table A-2.

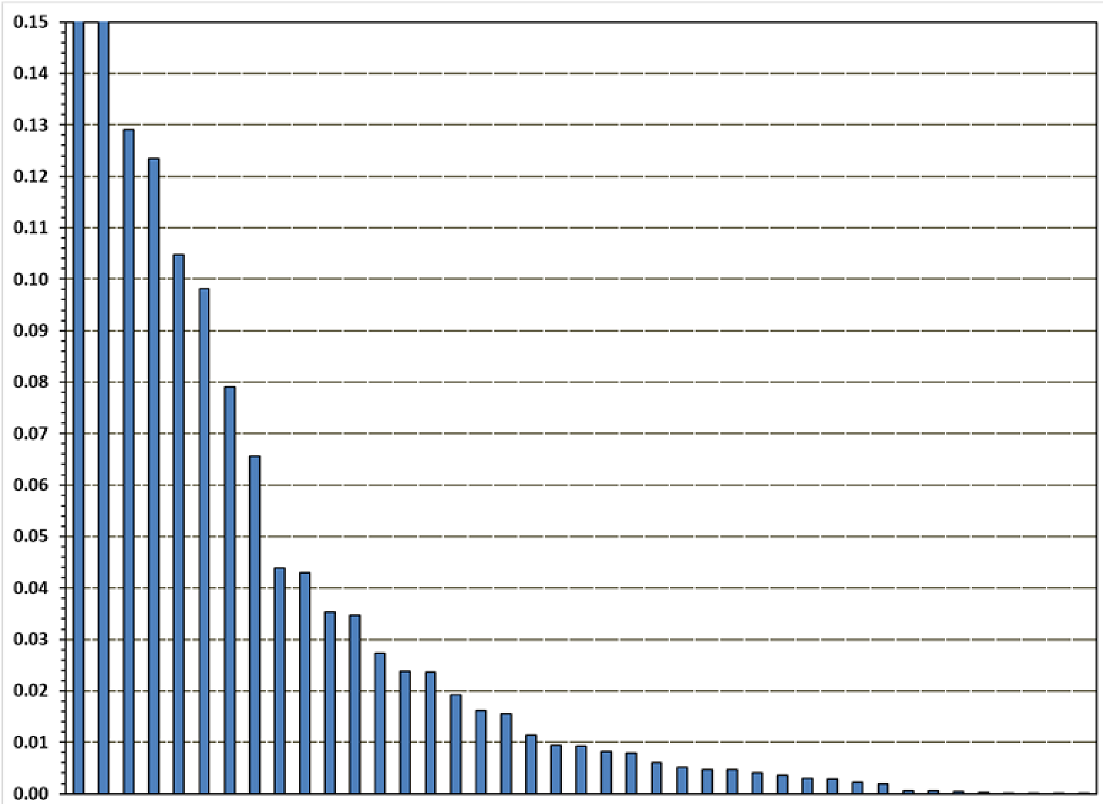

Figure A-1. Rank-ordered maximum downwind contributions from individual industries

We then examined the data for Metrics 2 and 4 for each industry that has a maximum contribution >= 0.01 ppb. The data for Metric 4, as shown in Figure A-2, suggests that there as a breakpoint between those industries that contribute to 10 or more receptors versus those industries that contribute to fewer than 10 receptors. Table A-2 provides the data for Metrics 2 and 4, ranked by the magnitude of Metric 4. The data show that 8 industries contribute >= 0.01 ppb to more than 10 receptors. Of these 8 industries, 5 have a maximum contributions of > 0.10 ppb to one of these receptors. In addition, one industry, Basic Chemical Manufacturing, contributes to only 9 receptors, but the maximum contribution to one of these receptors is >0.10 ppb. Using this information, we grouped the 9 industries into one of 2 tiers based on considering both the magnitude of the contribution and the downwind extent of affected receptors. Tier 1 includes the 4 industries that each have (1) a maximum contribution to any one receptor of >0.10 ppb and (2) a contribution >= 0.01 ppb to at least 10 receptors. Tier 2 includes the 5 industries that each have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors.

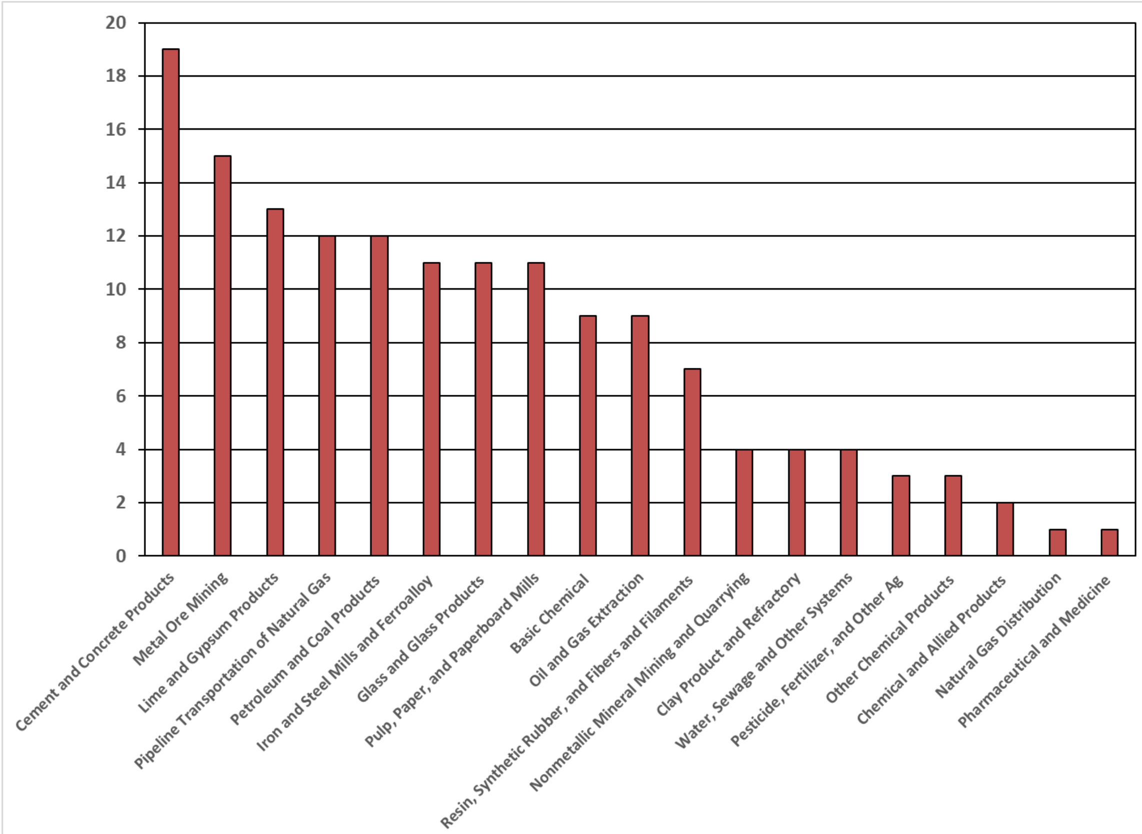

Figure A-2. Number of downwind receptors with contributions >= 0.10 ppb for each industry with a maximum downwind contribution >= 0.01 ppb

Table A-2. Maximum downwind contribution and number of receptors with contributions >= 0.01 ppb

Industry	Max Downwind Contribution	# Receptors with Contributions >= 0.01 ppb
Cement and Concrete Products	**0.231**	**19**
Metal Ore Mining	0.079	**15**
Lime and Gypsum Products	0.066	**13**
Pipeline Transportation of Natural Gas	**0.287**	**12**
Petroleum and Coal Products	0.098	**12**
Iron and Steel Mills and Ferroalloy	**0.129**	**11**
Glass and Glass Products	**0.105**	**11**
Pulp, Paper, and Paperboard Mills	0.043	**11**
Basic Chemical	**0.123**	9
Oil and Gas Extraction	0.035	9
Resin, Synthetic Rubber, and Fibers and Filaments	0.027	7
Nonmetallic Mineral Mining and Quarrying	0.035	4
Clay Product and Refractory	0.024	4
Water, Sewage and Other Systems	0.016	4
Pesticide, Fertilizer, and Other Ag	0.044	3
Other Chemical Products	0.024	3
Chemical and Allied Products	0.019	2
Natural Gas Distribution	0.016	1
Pharmaceutical and Medicine	0.011	1

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Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	**1.679**	**0.287**	**0.084**	**12**	**12**
Cement and Concrete Product Manufacturing	61	84	36,244	**1.871**	**0.231**	**0.094**	**19**	**13**
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	**0.577**	**0.129**	**0.029**	**11**	1
Basic Chemical Manufacturing	38	78	9,612	**0.293**	**0.123**	**0.015**	**9**	**2**
Glass and Glass Product Manufacturing	38	53	12,059	**0.695**	**0.105**	**0.035**	**11**	**7**
Petroleum and Coal Products Manufacturing	47	94	8,163	**0.733**	**0.098**	**0.037**	**12**	**6**
Metal Ore Mining	9	21	17,778	**0.687**	**0.079**	**0.034**	**15**	**3**
Lime and Gypsum Product Manufacturing	31	60	8,856	**0.531**	**0.066**	**0.027**	**13**	**3**
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	**0.162**	**0.044**	0.008	**3**	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	**0.306**	**0.043**	**0.015**	**11**	**3**
Oil and Gas Extraction	59	139	9,150	**0.207**	**0.035**	**0.010**	**9**	**2**
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	**0.167**	**0.035**	0.008	**4**	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	**0.152**	**0.027**	0.008	**7**	**2**
Other Chemical Product and Preparation Manufacturing	7	8	683	**0.074**	**0.024**	0.004	**3**	1
Clay Product and Refractory Manufacturing	1	2	1,098	**0.088**	**0.024**	0.004	**4**	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	**0.032**	**0.019**	0.002	**2**	1
Natural Gas Distribution	6	17	1,027	**0.058**	**0.016**	0.003	1	1
Water, Sewage and Other Systems	6	6	375	**0.069**	**0.016**	0.003	**4**	1
Pharmaceutical and Medicine Manufacturing	2	2	300	**0.057**	**0.011**	0.003	1	1
Grain and Oilseed Milling	4	4	376	**0.042**	0.009	0.002	0	0
Lessors of Real Estate	2	2	138	**0.037**	0.009	0.002	0	0
Nonferrous Metal (except Aluminum) Production and Processing	1	4	408	**0.025**	0.008	0.001	0	0
Sugar and Confectionery Product Manufacturing	5	10	1,068	**0.043**	0.008	0.002	0	0
Electric Power Generation, Transmission and Distribution	4	4	296	**0.039**	0.006	0.002	0	0
Engine, Turbine, and Power Transmission Equipment Manufacturing	2	2	112	**0.020**	0.005	0.001	0	0
Agriculture, Construction, and Mining Machinery Manufacturing	1	1	73	**0.012**	0.005	0.001	0	0
Colleges, Universities, and Professional Schools	4	4	263	**0.030**	0.005	0.002	0	0
Coal Mining	5	5	283	**0.015**	0.004	0.001	0	0
Plastics Product Manufacturing	2	2	126	**0.012**	0.004	0.001	0	0
Architectural, Engineering, and Related Services	2	2	117	**0.013**	0.003	0.001	0	0
Motor Vehicle Parts Manufacturing	1	1	62	**0.011**	0.003	0.001	0	0
Advertising, Public Relations, and Related Services	1	1	51	0.009				
Waste Treatment and Disposal	5	5	376	0.010				
National Security and International Affairs	1	1	42	0.002				
Support Activities for Mining	1	1	56	0.003				
Beverage Manufacturing	1	1	45	0.002				
Veneer, Plywood, and Engineered Wood Product Manufacturing	1	1	9	0.001				
Scientific Research and Development Services	1	1	78	0.001				
Alumina and Aluminum Production and Processing	1	1	13	0.000				
Other Food Manufacturing	1	1	45	0.000				
Office Administrative Services	1	1	5	0.000				
Total	591	1,199	164,962	8.77				
Tier 1 Industries	257	579	87,267	4.82				
Tier 2 Industries	171	326	51,182	2.55				
Tier 1 Industries (% of Total)	43%	48%	53%	55%				
Tier 2 Industries (% of Total)	29%	27%	31%	29%				

Legend

	Maximum Contribution	# Receptors with Contributions >=0.01 ppb	Total Contribution	# States with Highest Contribution >= 0.01
Break Points	0.01 to 0.04	> 1 to 9	0.1 to 0.4	> 1 to 9
	>= 0.05	>= 10	>= 0.5	>= 10

1st Tier of Industries for Further Analysis Based on AQ Contributions

These industries (1) have a maximum contribution to any one receptor of >0.10 ppb AND (2) contribute >= 0.01 ppb to at least 10 receptors.

2nd Tier of Industries for Further Analysis Based on AQ Contributions

These industries either have:

(1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or

(2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors

APPENDIX B – SUMMARY OF FACILITIES REMOVED in the SCREENING ASSESSMENT for 2026

REGION_CD	FACILITY_ID	Reason for Removal	state	county	site_name	naics_code	naics_description	city
24001	7763811	Closure	MD	Allegany	Luke Paper Company	322121	Paper (except Newsprint) Mills	Luke
06029	4789011	Subject to Consent Decree	CA	Kern	LEHIGH SOUTHWEST CEMENT CO.	327310	Cement Manufacturing	MONOLITH
06029	4789311	Subject to Consent Decree	CA	Kern	CALIFORNIA PORTLAND CEMENT CO.	327310	Cement Manufacturing	MOJAVE
06071	4841311	Subject to Consent Decree	CA	San Bernardino	CEMEX - BLACK MOUNTAIN QUARRY PLANT	327310	Cement Manufacturing	APPLE VALLEY
18093	8225311	Units to be replaced by new kiln by 2023	IN	Lawrence	LEHIGH CEMENT COMPANY LLC	32731	Cement Manufacturing	Mitchell
26007	8127411	Subject to Consent Decree	MI	Alpena	Holcim (US) Inc. DBA Lafarge Alpena Plant	327310	Cement Manufacturing	ALPENA