This revised document replaces the version posted to EPA's website the morning of March 15, 2023. This corrected version is the final document in the rulemaking docket.

United States Environmental Protection Agency

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

Response to Public Comments on Proposed Rule [87 FR 20036, April 6, 2022]

Comments, letters, and transcripts of the public hearings are also available electronically through *http://www.regulations.gov* by searching Docket ID EPA-HQ-OAR-2021-0668

FOREWORD

This document provides the U.S. Environmental Protection Agency's (EPA) responses to public comments on the EPA's *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*. The EPA published a proposed rule in the *Federal Register* (FR) on April 6, 2022, at 87 FR 20036. The EPA received comments on this proposed rule via mail, email, and through a series of public outreach events, including a virtual public hearing that was held on April 21, 2022.

Copies of all comments received, and the certified transcript prepared for the public hearing held are available at the EPA Docket Center Public Reading Room. Note that out of an abundance of caution for members of the public and our staff, and to reduce the risk of transmitting Coronavirus disease 2019 (COVID-19), the EPA Docket Center and Reading Room are open to the public but require all individuals to complete a self-assessment prior to accessing EPA facilities. The EPA Docket Center and Reading Room are open 8:30 am – 4:30 pm Monday - Friday (except Federal Holidays). For more information and updates on the EPA Docket Center services and the current status, please visit us online at https://www.epa.gov/dockets. In addition, copies of submitted public comments, along with copies of the published hearing transcript are available electronically through Regulations.gov (by searching Docket ID: EPA-HQ-OAR-2021-0668).

More than 112,000 public comments were received on the proposed rule. The EPA Docket Center consolidated mass mail campaigns and petitions into single document control numbers (DCNs), resulting in more than 704 posted comments. Each of these comments was reviewed, and significant comments relevant to this action that were submitted within the comment period (*i.e.*, received on or before June 21, 2022) have been included in this document and summarized below.

It is possible some responses in this Response to Comments (RTC) document may not reflect the language in the preamble and final rule in every respect. Where the response conflicts with the preamble or the final rule, the language in the final preamble and regulatory text should be used for purposes of understanding the scope, requirements, and basis of the final rule. The responses presented in this document are intended to augment the responses to comments that appear in the preamble to the final rule or to address comments not discussed in that preamble. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to the comments or responses, the preamble itself remains the definitive statement of the rationale for the revisions adopted in the final rule. In many instances, responses presented in this RTC document include cross references to responses on related issues that are located either in the preamble or elsewhere in the Response to Comments Document. Accordingly, the RTC document, together with the preamble and final rule, and the rest of the administrative record should be considered collectively as the Agency's response to all the significant comments submitted on the proposed rule.

Contents

ABBREVIATIONS AND ACRONYMS

ACE	Affordable Clean Energy
AECT	Association of Electric Companies of Texas
AEP	American Electric Power’s
AL	Alabama
AMP	American Municipal Power
AMPD	Air Markets Program Data
APA	Administrative Procedures Act
AL	Alabama
APCA	Anthropogenic Precursor Culpability Assessment
APPA	American Public Power Association
AQAT	Air Quality Assessment Tool
ARB	Air Resources Board
ASTM	American Society of Testing and Materials
AVOC	Anthropogenic VOCs
AZ	Arizona
BACT	Best available control technology
BARCT	Best available retrofit control technology
BAT	Best Available Technology
BF	Blast furnace
BFG	Blast furnace gas
BIPOC	Black, Indigenous, and people of color
BOF	Basic oxygen furnace
BOPF	Basic oxygen process furnace
BPP	Bonanza Power Plant
CA	California
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMx	Comprehensive Air Quality Model with Extensions
CARB	California Air Resources Board
CCR	Coal Combustion Residuals
CD	Consent decree
CE	Control efficiency
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	Continuous emission monitoring system
CFC	National Rural Utilities Cooperative Finance Corporation
cfm	Cubic feet per minute
CFR	Code of Federal Regulations

CH_4	Methane
CMDB	Control Measures Database
Co	Company
CO	Colorado
CO	Carbon monoxide
CO_2	Carbon dioxide
CoST	Control Strategy Tool
COVID-19	Coronavirus disease 2019
CPI	Consumer Price Index
CPMS	Continuous parameter monitoring system
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Connecticut
CTI	Cleaner Trucks Initiative
DC	District of Columbia
DCN	Document Control Number
DE	Delaware
DEC	Department of Environmental Conservation
DEQ	Department of Environmental Quality
DFW	Dallas-Fort Worth
DMNFR	Denver Metro / North Front Range
DOE	Department of Energy
DV	Design value
EA	Engineering Analytics
EAF	Electric arc furnaces
EEA2	Energy Emergency Alert 2
EGUs	Electric Generating Units
EIA	Economic Impact Analysis
EIA	Energy Information Administration
EJ	Environmental justice
EKPC	East Kentucky Power Cooperative
EMP	Emissions Modeling Platform
EO	Executive Order
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERTAC	Eastern Regional Technical Advisory Committee
ESP	Electrostatic precipitators
EU	European Union

FF	Fabric filter
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FIP	Federal Implementation Plan
FPA	Federal Power Act
FR	Federal Register
GAO	Government Accountability Office
GHG	Greenhouse gases
GNR	Good Neighbor Rule
GW	gigawatt
HAP	Hazardous air pollutant(s)
EGU	Electric generating unit
HGB	Houston Galveston-Brazoria
HQ	Headquarters
hr	Hour
HRSG	Heat recovery steam generators
HUD	Department of Housing and Urban Development
HYSPLIT	Hybrid Single-Particle Lagrangian Integrated Trajectory
H_2O	Water
ICI	Industrial, Commercial, and Institutional
ID	Identification
IIJA	Infrastructure Investment and Jobs Act
IL	Illinois
IN	Indiana
INGAA	Interstate Natural Gas Association of America
IPM	Integrated Planning Model
IRP	Integrated Resource Plans
ISO	Independent System Operators
kg	Kilograms
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest achievable emissions rate
lbs/mm/Btu	Pounds per million BTUs
LEC	Low emissions combustion
LEUEG	Louisiana Electric Utility Environmental Group
LMF	Ladle metallurgical furnaces
LMOS	Lake Michigan Ozone Study
LME	Low mass emissions
LPPC	Large Public Power Council

MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics
MDA8	Maximum daily 8-h average
MI	Michigan
$\mu g/m^3$	Micrograms per meter cubed
MISO	Midcontinent Independent System Operator
MO	Missouri
MOG	Midwest Ozone Group
MPCA	Minnesota Pollution Control Agency
MW	megawatt
MWC	Municipal waste combustor
MWh	Megawatts hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NEEDS	National Electric Energy Data System
NEI	National Emissions Inventory
NEPA	National Environmental Protection Act
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFR	Northern Front Range
NH3	Ammonia
NJ	New Jersey
NMED	New Mexico Environment Department
NNSR	Nonattainment New Source Review
NODA	Notice of Data Availability
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NPRM	Notice of proposed rulemaking
NRECA	National Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NTAA	National Tribal Air Association
NUSA	New Unit Set Aside
NW	Northwest
NWF	Northern Wasatch Front
NYMA	New York metropolitan area
OAC	Ohio Administration Code

OAQPS	Office of Air Quality Planning and Standards
OAR	Office of Air and Radiation
OH	Ohio
OK	Oklahoma
OMB	Office of Management and Budget
OSAT	Ozone Source Apportionment Technology
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
O_3	Ozone
O&M	Operations and maintenance
PA	Pennsylvania
PCA	Portland Cement Association
PCM	Pusher charger machine
PEMS	Predictive Emission Monitoring System
PM	Particulate matter
$PM_{2.5}$	PM with a diameter of 2.5 micrometers or less; fine particulate
ppb	Parts per billion
ppm	Parts per million
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
PUCT	Public Utility Commission of Texas
QA/QC	Quality Assurance/Quality Control
RACT	Reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
RCF	Relative Contribution Factor
RIA	Regulatory Impact Analysis
RICE	Reciprocating internal combustion engine
RMP	Risk Management Plan
RMR	Reliability-must-run
RRF	Relative Response Factor
RTC	Response to Comments
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SAF	Submerged arc furnace
SCC	Social cost of carbon
SCCT	Simple cycle and regenerative combustion turbines
SC-CO2	Social cost of carbon dioxide
SC_GHG	Social cost of greenhouse gases
SCR	Selective catalytic reduction

SDA	Spray dry absorber
SERC	Southeast Regional Council
SIP	State Implementation Plan
SMA	Steel Manufacturers Association
SSM	Startup, shutdown, and malfunction
SNCR	Selective Non-Catalytic Reduction
SoCal	Southern California
SPP	Southwest Power Pool
STEC	South Texas Electric Cooperative
SWEPCO	Southwestern Power Electric Company
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TN	Tennessee
tpy	Tons per year
TSD	Technical Support Document
TVA	Tennessee Valley Authority
TX	Texas
UB	Uinta Basin
UDAQ	Utah Division of Air Quality
ULNB	Ultra low NOx burner
U.S.	United States
U.S.C.	United States Code
USGS	U.S. Geological Survey
UT	Utah
VDGs	Vacuum degassers
VOC	Volatile organic compounds
WESTAR	Western States Air Resources Council
WI	Wisconsin
WRAP	Western Regional Air Partnership
WY	Wyoming
yr	Year
2SLB	2-stroke lean burn
4SRB	4-stroke rich burn
4SLB	4-stroke lean burn

INTRODUCTION

This document provides a summary of public comments and the Environmental Protection Agency's (EPA's) responses to those comments on the proposed rule titled, *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard*, published in the *Federal Register (FR)* on April 6, 2022 (87 FR 20036).

Just over 112,120 public comments were received on the proposed rule. The EPA Docket Center consolidated mass mailing campaigns, form letters, and petitions into single docket control numbers (DCNs), resulting in 704 posted comments. Note that batches of substantially similar comments (*e.g.*, mass letter campaigns) are considered a "single comment." Of the more than 700 posted comments, only a small number were identified as duplicate comments or comments unrelated/non-applicable to the proposed rule, and the remaining comments were categorized as "unique."

Less than 2 percent of the "unique" comments were written copies of oral testimonies given at the virtual public hearing held by the EPA on April 21, 2022. Over 80 speakers provided oral testimony and more than 160 people attended as observers. Live testimonies were recorded by a certified court reporter and documented in an official transcript, which is available at http://www.regulations.gov (see EPA-HQ-OAR-2021-0668-0254). Summaries of oral testimonies are included in this document, if, for example, the commenter provided "actionable" remarks but did not submit a separate, more detailed comment to the Docket; otherwise, copies of oral testimonies given at the virtual public hearing are documented in the certified public hearing transcript.

Of the nearly 700 comments categorized as unique, more than 43 percent (over 300 comments) were identified as providing detailed, "actionable" remarks. These remarks are presented and summarized, along with the EPA's responses, in Chapters 1 through 11 in this Response To Comments (RTC) document.

Most of the unique comments identified originated from private citizens – over 50 percent. Many of these commenters included, as part of their own remarks, sections of one or more mass mailer, form letter, and/or petition. The remaining comments are broken down as follows: roughly 23 percent of comments received are from industry groups (including industry associations), 9 percent are from government representatives, 8 percent are from non-profit, public health and environmental advocacy groups, 3 percent are from mass mailers/form letters (representing more than 111,400 commenters), 3 percent are from other types of organizations or affiliations not listed specifically, and less than 1 percent are from academia. There were no comments submitted by the media or press, nor did any federal government official or representative submit comments directly to the Docket.

A complete, comprehensive list of unique comments received on this proposal is provided in **Appendix A** of this document. Comment submissions are listed by DCN, commenter name and affiliation/organization, and commenter type (*e.g.*, industry, academia, private citizen, etc.).

The public comment period for the proposed rule was first scheduled to close on June 6, 2022; however, the EPA received a number of requests for additional time to review and comment on the proposed rule revisions. Accordingly, the EPA extended the deadline to submit comments by fifteen (15) days, to June 21, 2022. The comment period officially closed on June 21, 2022.

After the close of the comment period, the EPA received 3 late comments. Late comments received were reviewed, and they are summarized in this document if the comment included pertinent remarks or information not covered by previously submitted comments. One late comment is included in this document and is indicated (in this document) by the last 4 digits of the DCN for the comment letter and an "L" (*e.g.*, XXXXL) to indicate it was a late comment.

As previously mentioned, actionable, more-detailed remarks submitted to the Docket, along with the EPA's responses are presented in Chapters 1 through 11. General remarks from private citizens, in addition to comments prepared by mass mail campaigns are summarized below.

<u>Mass Mail Campaigns/Petitions</u>

Mass comment campaigns represent nearly 111,500 of the more than 112,000 commenters (greater than 99 percent) who submitted comments to the Docket on the proposed rule. These mass comment campaigns consist of mass mailers, which are comment letters that contain duplicate or substantially similar comments that repeat a company's or organization's message and are typically sponsored by one or more organization/institution; and petitions, which are letters that contain a formal request to support or oppose specific statements, often containing a compilation of supporting signatures.

Mass mailers account for almost 38 percent (representing more than 42,500 private citizens) of the mass comment campaigns identified. Most participants submitted templates provided by the sponsoring organization(s) without change; however, a few commenters customized the template(s) to include statements describing personal experiences with deteriorating health. Petitions account for over 62 percent of the mass comment campaigns identified and represent more than 68,800 private citizens.

Of the mass comment campaigns, 38 percent of them were sponsored/prepared by an unknown agency or organization. Of those with an identified sponsoring organization, nearly all were coordinated by an environmental and/or public advocacy group. Several of the mass campaign sponsoring agencies submitted similar or identical arguments. A list of campaigns received is provided in **Appendix B** to this document. Examples for a couple of mass comment campaigns can be found in **Appendix C** to this document. Although over 370 "Private Citizens" included one or more mass mail campaign arguments, their comments varied enough (though not by much) to not be grouped and categorized as mass campaign comments.

COMMENTS AND RESPONSES

1 Legal Comments on the EPA's Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

General Comments

Comments:

Commenters (0259, 0300, 0402, 0433, 0515) provide a brief summary of Clean Air Act (CAA) section 110(a)(2)(D)(i)(I), also known as the "good neighbor" provision," and express their support, in general, with the EPA's decision to propose a Federal Implementation Plan (FIP) for those states that failed to submit an adequate plan, as authorized under the CAA and the "good neighbor." Commenter (0515) believes that the "good neighbor" provision of the CAA (42 United States Code (U.S.C.) § 7410(a)(2)(D)(i)(I)) is a critical and important tool to address nonattainment with the national ambient air quality standards (NAAQS) – this includes the EPA's efforts to promote market-based solutions that will achieve the 2015 ozone NAAQS in a cost-effective, expeditious manner. Commenter (0515) claims that by putting a price on emissions and doing so in a manner that incentivizes dispatch of the lowest emitting units in the interconnected electricity grid, the proposed rule would leverage market forces to help achieve the 2015 NAAQS at the lowest cost to consumers.

In contrast, commenters (0262, 0306, 0323, 0326, 0346, 0359, 0365, 0366, 0372, 0382, 0394, 0395, 0400, 0407, 0409, 0435, 0504, 0500, 0509, 0512, 0513, 0538, 0546, 0547, 0509, 0519, 0538, 0547, 0550, 0551, 0760, 0798) claim that the EPA's proposed transport FIP, as written, extends beyond the authority granted to the Agency by Congress and under the CAA "good neighbor" provision. Generally, commenters believe that the proposed FIP is arbitrary, capricious, and not in accordance with current law for a number of reasons, including for example: (1) the proposed FIP arbitrarily picks winners and losers, establishing an unprecedented regulation of seven industries, many of which likely cannot comply with the proposed FIP in a cost-effective manner; (2) the proposed FIP attempts to overhaul the energy sector in violation of the "major questions" and "nondelegation" doctrines; (3) The proposed FIP "over-controls" states, resulting in greater emissions reductions than necessary to meet the NAAQS; (4) the EPA abruptly shifts compliance standards for reasons other than environmental protection and does so after states have relied on those standards to prepare a State Implementation Plan (SIP), and then attempts to regulate states for which the EPA has not finalized a SIP disapproval; and (5) the proposed FIP attempts to grant the EPA authority already delegated by Congress to other agencies. The commenters, as a whole, agree that the proposed FIP should be abandoned.

Commenters (0286, 0361, 0505, 0764) express general concerns that portions of the proposed rule are not legally justified and that the EPA has failed to demonstrate its authority to follow the course of action laid out in the proposed rule.

Response:

These comments provide general support or opposition to this action and do not require a specific response. The EPA has addressed each of commenters' specific comments in the preamble, this RTC document, or other support materials.

1.1 Sequencing of State Implementation Plan (SIP) and Federal Implementation Plan (FIP) Actions

1.1.1 The EPA Authority to Promulgate a FIP

Comments:

Commenters (0509, 0512, 0513, 0528, 0542, 0550, 0760, 0798) explain that the EPA lacks the authority to promulgate a FIP until after a state has failed to submit a SIP or the EPA has disapproved a state's submittal. Commenters (0400, 0518, 0542, 0798) note that the EPA proposed the FIP before proposing to disapprove several SIPs for covered states or issuing final disapprovals for the rest. Commenter (0798) states that "no court decision has ever authorized the EPA to propose a FIP before taking the predicate final action of disapproving a SIP in the states the FIP is proposed to cover. In fact, the D.C. Circuit expressly reserved judgement on this very issue the last time it was raised before the D.C. Circuit, dismissing it on administrative exhaustion grounds rather than approving the EPA's approach. Nor does the Supreme Court's opinion in EME Homer address this issue, as that opinion only determined that the EPA need not provide States an additional opportunity to revise its SIP after disapproval of a SIP, not whether a FIP can be issued before disapproving a SIP in the first place."

Commenters (0512, 0513) write that under CAA section 110, states retain primary authority to address their ozone transport obligations until the EPA has taken final action on a SIP submission.

Commenters (0359, 0372, 0395, 0500, 0513, 0519) declare that the EPA's proposed FIP exceeds its authority under CAA section 110(c) by attempting to regulate states (including Oklahoma, Texas, Kentucky, West Virginia) for which the EPA has not finalized a SIP disapproval. At least one commenter states that the EPA's "anticipated" findings are not final determinations and do not fulfill the EPA's statutory obligation to approve or disapprove submitted SIPs. Commenters further note that under the CAA section 110, states retain primary authority to address their ozone transport obligations until the EPA has taken final action on a SIP submission. The commenters underscore the point that CAA section 110(k) requires the EPA to take final action to approve or disapprove a state's SIP, once submitted, within 18 months; however, the EPA exceeded this deadline for several states purportedly covered by the "Good Neighbor" plan.

Commenter (0405) states that the EPA's time frame for proposing the FIP is not required by statute and did not afford adequate time for more robust modeling by states and regional modeling groups to assess the need for non-electric generating unit (EGU) emissions reductions to reduce transport of emissions to downwind states. The EPA is obligated to impose only those emissions reductions necessary to mitigate the adverse effects on attainment in downwind states. Local and regional modeling resources are essential to finding the most efficient and effective measures to mitigate only those emissions necessary to address downwind effects.

Commenter (0798) comments that many aspects of the proposed rule exceed the discretion granted to the EPA under the statutory text, and thus will not be protected by Chevron deference, and may serve as a basis for challenges to Chevron itself, or at least to further limits on the EPA's deference under Chevron. Commenter says the proposed rule only applies by virtue of the EPA's disapproval of various SIP plans. In disapproving those state plans (which is a statutory prerequisite for the EPA authority to issue the proposed Rule) the EPA effectively asserted that it would prefer to institute a FIP as opposed to individual SIP demonstrations due to a wish to address ozone transport in a "nationally uniform approach" with "nationwide scope and effect" based on a "common core of nationwide policy judgements." But the EPA lacks discretion to decide that regional ozone transport is a national problem that requires national uniformity (*e.g.*, by setting industry wide emissions limits based on a "common core of nationwide policy judgements" without regard to state specific contribution considerations). Congress already unambiguously made a contrary decision by making the EPA's discretion to implement a FIP subject to SIP submissions that the EPA "shall" approve if the statutory elements are met. [see 42 U.S.C. § 7410(k)(3); CAA Sec. 107(a)] "Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State." Simply put, the EPA lacks discretion to decide that it would prefer a uniform national approach for good neighbor provisions. *Train v. Natural Resources Def. Council*, 421 U.S. 60, 79 (1975) ("The Act gives the Agency no authority to question the wisdom of a State's choices of emissions limitations if they are part of a plan which satisfies the standards of § 110(a)(2), and the Agency may devise and promulgate a specific plan of its own only if a state fails to submit an implementation plan which satisfies those standards."); *Concerned Citizens of Bridesburg v. U.S. E.P.A*, 836 F.2d 777, 780–81 (3d Cir. 1987) (holding the Clean Air Act "left the mechanics of achieving NAAQS to the states. Section 7410(a) requires each state to formulate and submit to the EPA a SIP detailing regulations and source-by-source emissions limitations that will conform the air quality within its boundaries to the NAAQS. The SIP basically embodies a set of choices regarding such matters as transportation, zoning and industrial development that the state makes for itself in attempting to reach the NAAQS with minimum dislocation. Because the states have primary responsibility for achieving air quality standards, the EPA has limited authority to reject a SIP."); *Commonwealth v. Environmental Protection Agency*, 108 F.3d 1397, 1410 (D.C. Cir. 1997) ("section 110 does not enable EPA to force particular control measures on the states"). Accordingly, the EPA deserves no deference in any decision to prefer a nationwide FIP based on a "common core of nationwide policy judgements" over a SIP based on "a set of choices regarding such matters as transportation, zoning and industrial development that the state makes for itself.

Commenter (0362) states that by concurrently issuing a proposed FIP and disapproving 21 SIPs, the EPA subverted state authority, which is counter to the intended primacy of the states in the CAA. Commenter quotes 42 USC § 7401(a)(3)-(4) as evidence of this Congressional intention. Commenter requests that the EPA rescind the proposed disapprovals and work with states to reduce emissions.

Commenter (0542) writes that "EPA's actions have assured that Mississippi will have no opportunity to replace the FIP with a revised SIP prior to the FIP's effective date. In so doing, the EPA is usurping state authority and mandating to states how they must achieve compliance without giving states the freedom to implement measures other than those chosen by the EPA. The EPA's approach conflicts with CAA precedent: The D.C. Circuit has held that the EPA under the CAA cannot "commandeer the regulatory powers of the states." It also conflicts with the D.C. Circuit's good neighbor precedent, which confirms that "EPA does not tell the states how to achieve SIP compliance" but rather the EPA "looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms." Commenter continues, "EPA has given Mississippi and other states no choice in the implementation of the Transport Rule FIP. Rather than allowing states to develop their own compliance strategies, the EPA made those choices for them. In violation of the CAA and related case law, the EPA has unlawfully commandeered the states' discretion to address good neighbor obligations in a manner of its choosing. The EPA's actions here represent the exact opposite of cooperative federalism. The EPA should have issued a SIP call and provided states a "reasonable deadline" for submission of plan revisions upon findings of inadequacies rather than dictating its own choices for compliance with section 110 of the Clean Air Act."

Commenter (0365) contends that the EPA failed to comply with the CAA and 42 U.S.C. Section 7410(k)(2), which requires that the EPA act on a SIP submittal (*i.e.,* approve the submittal in part and disapprove in part, or issue a disapproval) within twelve months from the date of a finding of completeness [pursuant to 42 U.S.C. § 7410(k)(l)(B)]. The commenter states that pursuant to 42 U.S.C. § 7410(c)(1), that the EPA shall promulgate a FIP at any time within two years after the EPA issues a final disapproval of a SIP in whole or in part, unless the state corrects the deficiency, and the EPA approves the revisions prior to FIP promulgation. The comment underscores the point that the EPA has not issued disapproval of Louisiana's interstate transport SIP. Commenter (0365) notes that Louisiana is currently regulated by the CSAPR FIP, last revised June 30, 2021, and the EPA is proposing to amend the CSAPR FIP within another FIP through the proposed rule. Commenter argues that this is evidence of an inconsistent regulatory process.

Commenter (0509) quotes the Western Governors Association Policy Resolution 2021-01 on "Strengthening the State-Federal Relationship," which states, "Too often, federal agencies: solicit input from states after a decision is already made or a public process is started; ask states to provide feedback on a proposed action without providing details or documents regarding what the agency is proposing; or do not respond to state input or incorporate feedback from states into their decisions. This does not afford states with the respect and communication required by law, and states currently have no recourse for an agency's failure to consult except for litigation on the merits of a federal decision."

Commenters (0306, 0365, 0411, 0798) argue that the EPA unconstitutionally infringes into matters reserved for the states and contradicts or undermines the cooperative federalism approach of the CAA by proposing this FIP instead of allowing the states to manage their own emissions through SIPs.

Commenter (0798) explains that state primacy in developing implementation plans and the opportunity to cure perceived defects in implementation plans are two examples of a broader theme of cooperative federalism that runs throughout the CAA. Commenter believes that in proposing the FIP, the EPA obviated Congress' intentions that the CAA be implemented across the county in a manner that uses cooperative federalism. Instead, the EPA unilaterally rejects the State's approaches to regulating interstate transport of NO_X originating within their borders and would impose the EPA's own "unproven and infeasible" preferred approach to fulfill CAA ozone transport requirements. In doing so, the EPA improperly treated the state SIPs are "initial recommendations" over which the EPA could impose its own "final judgments under the guise of surveillance and oversight."

Commenter (0266) is concerned that the EPA may be imposing implementation steps as a part of this FIP on the states as if it is a SIP. The commenter recommends that the EPA provide clarity in the preamble on the state's role in the EPA's FIP.

Commenter (0398) states that the EPA violates cooperative federalism as set out in CAA section 110 and elsewhere by mandating the use of particular control technologies in specific industry sectors to meet the NAAQS. Commenter explains:

> "EPA can set the standards, but it is up to each state to determine how to meet the standards. Although the proposed FIP provides that states may submit SIPs to address the provisions of the proposed FIP, the proposed FIP provides no realistic ability for states to do so except as mandated in the FIP, particularly for non-EGU sources. For EGU sources, the FIP sets forth alternatives available to trading programs for EGUs that a state may adopt, but it provides no such alternatives for non-EGUs. In fact, the FIP essentially states that the EPA will not approve a substitute SIP for non-EGUs that does not "include emissions limits at an equivalent or greater level of stringency than is specified for nonEGU sources . . . identified in Section VII.C of this proposed rule." EPA goes on to say that demonstrating equivalency "using other control strategies" is complicated because the non-EGU standards are "generally rate based and expressed in a variety of forms," and that the reductions "must be achieved on the same time frame as the reductions that would be required in the final FIP." EPA's FIP neither provides nor signals EPA's intent to approve SIPs for non-EGUs that do not adopt EPA's specific emissions control requirements. The EPA may not "condition approval of a state's implementation plan on the state's adoption of a particular control measure," which the FIP purports to do. This is not permitted under the CAA."

Commenter (0551) describes how cooperative federalism was interpreted by the D.C. Circuit in *Michigan v. EPA* and how that finding applies to the proposed rule:

> "The D.C. Circuit determined in *Michigan* that EPA's clearly stated NO_X budgets, intended to remedy significant contribution to downwind nonattainment or maintenance problems, passed the Train-Virginia federalism bar for three reasons: (1) the budgets "merely provide[d] the levels to be achieved by state-determined compliance mechanisms;" (2) "EPA made clear that states do not have to adopt the control scheme that EPA assumed for budget- setting purposes;" and (3) the "budget program does not mandate a 'specific, source-by-source emissions limitation.'"

Unlike the NO_X SIP Call, the proposed rule unfortunately has problems on each of these fronts. First, as explained above, the EPA has not provided budgets for each compliance year. Thus, states cannot determine for themselves what their compliance plans must achieve. As the D.C. Circuit in *North Carolina* explained, if a state declines to participate in the EPA's interstate trading program, then "the state must limit its emissions to a cap specified by" the applicable trading program. A state cannot replace the EPA's FIP with a SIP adopting alternative emissions control requirements when the EPA has failed to supply defined emissions budgets. It is worth noting, the issue of the EPA providing clearly articulated budgets to empower states to carry out their statutory role under the CAA is separate from the issue addressed by the Supreme Court in EME Homer II, which involved the EPA's obligation to provide budget information prior to promulgating a FIP.

To effectuate the cooperative federalism framework of the CAA, the proposed rule should be revised to provide states with the tools they need to develop appropriate plans for compliance.

Second, the EPA's expressed intention is to require the operation of emissions controls regardless of overall emissions reduction, effectively mandating a specific control scheme and removing the state's right to adopt alternative compliance mechanisms.

Third, even more clearly, the proposed rule would impose source-by-source emissions limits. The backstop emissions limit and the assurance level backstop function as "unit-specific secondary emissions limitations." Those limits are "intended to improve emissions performance at the level of individual units."

These aspects of the proposed rule all conflict with the CAA's cooperative federalism model. To effectively resolve these issues and pass the Train-Virginia federalism bar, the EPA must do the following:

- Provide budgets that will eliminate significant contribution
- Allow states to meet the goals of the proposed rule through a variety of control schemes
- Eliminate source-by-source limits

Response:

The EPA has established predicate authority to promulgate FIPs for each of the states covered by this action through its action on the relevant SIP submittals. See Section III.B.2 of the preamble. Commenters' apparent complaint that the EPA lacked adequate authority to issue FIPs at the time the EPA *proposed* the FIPs is not correct as a matter of law. The timing and contents of merely proposed actions are not considered final agency actions and are not subject to judicial review. *See In re Murray Energy*, 788 F.3d 330 (D.C. Cir. 2015). Further, complaints about the timing or substance of the EPA's actions on the SIP submittals are beyond the scope of this action. With these principles in mind, the timing of this final action is entirely lawful under the Act. 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. 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.” *See EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 509 (2014) (citations omitted). Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final action on a SIP (or finding no SIP was submitted). *See, e.g., Oklahoma v. EPA,* 723 F.3d 1201, 1204 (10th Cir. 2013). To accomplish this, the EPA must necessarily be able to propose a FIP prior to taking final action disapproving a SIP or making a finding of failure to submit.

One commenter asserts that the D.C. Circuit has reserved judgment on whether the EPA may propose a FIP before taking final action disapproving A SIP. The commenter miscites an inapposite passage in the D.C. Circuit’s decision on remand in *EME Homer City*, 795 F.3d 118. The correct pincite is to page 137 of the Federal Reporter. And the court there declined to entertain a different argument: that the EPA may not promulgate a FIP before a final SIP disapproval is published in the Federal Register. That passage says nothing regarding the court’s views on whether the EPA may propose a FIP before taking final action on a SIP, or even on the question before it.

The EPA’s authority to directly implement pollution control requirements when it promulgates a FIP and why the so-called *Train-Virginia* federalism bar is inapplicable to a FIP are addressed in Section 1.2 (Authority to Establish Emissions Limits and Control Requirements).

The EPA has provided multiple methods by which states can replace the FIP with a SIP and recognizes states’ flexibility to develop replacement SIPs that differ even from these options. This is addressed further in Section VI.D of the preamble.

One commenter asserts the EPA has an “inconsistent regulatory process” by promulgating a FIP through amending a prior FIP, but this comment is not adequately explained and is not accurate in any case. The EPA has established necessary FIP authority through action on states’ SIP submittals addressing good neighbor obligations for the 2015 ozone NAAQS. The EPA has promulgated the relevant FIPs in this action through provisions codified in each of the state-specific subparts of 40 Code of Federal Regulations part 52. These provisions incorporate the amended Group 3 emissions trading program for most states covered by this action (not for California). Whether the form of that FIP or some aspect of its requirements is done in part through amendment of an emissions trading program promulgated as the means of implementing prior FIP authority is not precluded by any provision of the CAA.

The EPA disagrees that this action violates or implicates anti-commandeering principles. One commenter cites *District of Columbia v. Train*, 521 F.2d 971 (D.C. Cir. 1975), *vacated sub nom. EPA v. Brown*, 431 U.S. 99 (1977), for the proposition that the EPA cannot commandeer states’ resources or force them to implement federal policies or programs against their consent. No such commandeering of state regulatory authority or resources is occurring by virtue of this action. This action directly implements the relevant good neighbor obligations for the covered states, and states are not obligated to take any action to effectuate this. *See* CAA section 110(c)(1). *Cf. D.C. v. Train*, 521 F.2d at 993 (“[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 . . . .”).

The EPA also disagrees with the argument that applying a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations is inconsistent with the framework of cooperative federalism. These policy judgments interpret the CAA are consistent with relevant case law and past agency practice as reflected in the CSAPR 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 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 to ensure an "efficient and equitable" approach. See *EME Homer City Generation, LP* v. *EPA*, 572 U.S. 489, 519 (2014). One commenter argued that the regional nature of the problem of instate transport does not confer greater authority on the EPA. However, in highlighting the regional nature of transport, the EPA is not claiming a qualitatively different authority to promulgate a FIP to implement CAA section 110(a)(2)(D)(i)(I). The EPA's authority when it steps into the shoes of a state under CAA section 110(c)(1) is the same for both obligations associated with in-state pollution as is it for interstate pollution.

But the regional, interstate nature of the ozone-transport issue simply underscores the indispensability of the EPA's role as to these particular requirements. In this regard, the EPA notes that not a single State out of the 49 States that submitted a good neighbor SIP submission for the 2015 ozone NAAQS concluded that any emissions reductions beyond existing controls were necessary to satisfy CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. This fact is entirely unsurprising, but also confirms the need for federal intervention. As the D.C. Circuit observed with respect to regional haze, regional ozone pollution is a multi-state, collective-action problem posed by widespread pollution emitters, and thus,

> is a problem in which the benefits of each state's emissions controls are largely felt in other states. Without federal intervention, then, a state calculating how hard it should press in limiting pollution has no incentive to consider resulting enhancements of other states' welfare. There is no reason to believe that New Mexico, for example, would without federal pressure tighten limits for in-state polluters an extra notch so that tourists could gaze at clear skies above the Grand Canyon. Even an anti-pollution commitment demonstrated by 'numerous stakeholder meetings and public workshops across the West' does not explain why one state would, absent federal pressure, martyr itself for another, or subject its electric power users (for example) to additional costs for the benefit of out-of-state interests. Cf. *Maryland People's Counsel v. FERC,* 245 U.S. App. D.C. 365, 761 F.2d 768, 778 (D.C. Cir. 1985*)* ('It is ridiculous to assume that' a company would 'engage in . . . self-sacrificing behavior' 'simply because there is nothing that stops it from doing so').

Center for Energy and Econ. Devel. V. EPA, 398 F.3d 653, 657-58 (D.C. Cir. 2005) (Williams, J.).

The EPA has further responded to "cooperative federalism"-type arguments regarding the bases for its disapprovals of state SIP submissions in the separately finalized SIP disapproval action; those issues are beyond the scope of this action.

1.1.2 Role of 2018 Memoranda and Prior Modeling

Comments:

At large, commenters (0300, 0323, 0340, 0341, 0346, 0372, 0397, 0399, 0400, 0405, 0409, 0500, 0505, 0508, 0510, 0512, 0517, 0531, 0554, 0760, 0798) suggest that the EPA failed to adequately provide guidance to states at the time that states prepared and submitted their SIPs to meet NAAQS requirements. According to commenter (0300) when implementing the NAAQS, the EPA often outlines additional details, requirements, or flexibilities for a particular SIP through the issuance of additional regulations and/or guidance to clarify agency expectations. Several commenters, including commenter (0300) underscore the fact that the EPA diverged from its previously published guidance documents (*e.g.*, 2018 Guidance Memo) and used the fact that states followed this guidance as the basis for many SIP disapprovals. Commenter (0300) acknowledges that science continues to advance but argues that "the science that presents itself as the best path forward and relied upon by the EPA at the time of NAAQS implementation should continue to be relied upon until the issuance of a revised NAAQS, where new ideas and updated procedures may be required, or a SIP call is necessitated, which allows states adequate time to remedy any deficiencies identified as a result of newfound information."

Commenter (0323) states that the EPA should have provided updated guidance, new modeling, [and] instructions on corrections for specific state deficiencies. In a similar comment, commenter (0531) adds that the EPA has not given states ample opportunity to account for changes in air quality models and the EPA's new interpretations of guidance.

Moreover, commenter (0323) contends that the EPA's disavowal of its standing guidance in both the proposed disapproval of the 19 good neighbor SIPs and the proposed FIP is an arbitrary abuse of authority. The commenter further states that the EPA's actions demonstrate disregard for good faith efforts by the regional offices and state agencies to effectively implement "good neighbor obligations."

Commenter (0372) cites remarks that they previously submitted on the SIP denial and states their belief that the EPA should have provided notice of the reversal of its positions in guidance and then provided states a "reasonable deadline" for submission of plan revisions. The commenter further claims that due to the EPA's actions, states never had the opportunity to craft plans to address CAA section 110(a)(2)(D)(i)(I), contrary to the CAA framework. The commenter states that historically, the EPA has provided guidance to rulemaking activities; noting the Agency released 3 guidance documents in 2008 to help inform states on how to address their good neighbor obligations. However, the commenter (and commenter 0500) points out that the Agency has not provided or issued any other guidance since that time, while simultaneously declining to respond to SIP submittals by states – with the exception of approving Iowa's SIP in 2020.

Commenter (0306) believes that the EPA's proposals within the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards unconstitutionally infringe on Texas's sovereign powers and attempts to seize authority held by the legislative branch and other regulatory agencies.

Commenters (0362, 0365, 0395, 0798) state, in general, that it was unreasonable and unlawful forthe EPA to disapprove state SIP submissions, while concurrently issuing a proposed FIP, particularly (as stated by commenter 0798) when disapprovals are based on data that the Agency fail[s] to generate until after its statutory deadline to act. While the commenter (0798) acknowledges that the D.C. Circuit has held that the EPA has legal authority to propose a FIP at the same time it disapproves a SIP submission without giving the state an opportunity to fix the deficiency in the SIP submission, the commenter is unaware of a decision or statutory basis that would allow the EPA to do so based on data that was unavailable to the state at the time that it made its SIP submission.

Commenters (0300, 0323, 0340, 0341, 0346, 0397, 0399, 0400, 0405, 0409, 0505, 0508, 0512, 0517, 0531, 0554, 0760, 0798) object to the EPA's decision to base the proposed FIP and the SIP disapprovals on new or changed guidance, models, and data that were not available at the time that states were submitting SIPs. This includes, for example, the 2016v2 Model as well as memoranda written by Peter Tsirigotis in the EPA's Office of Air Quality Planning and Standards (OAQPS).

Commenter (0300) states that when implementing the NAAQS, the EPA often outlines additional details, requirements, or flexibilities for a particular SIP through the issuance of additional regulations and/or guidance to clarify agency expectations. Commenter observes that the EPA diverged from its previously-published guidance documents and used the fact that states followed this guidance as the basis for many SIP disapprovals. The commenter acknowledges that science continues to advance but argues that "the science that presents itself as the best path forward and relied upon by the EPA at the time of NAAQS implementation should continue to be relied upon until the issuance of a revised NAAQS, where new ideas and updated procedures may be required, or a SIP call is necessitated, which allows states adequate time to remedy any deficiencies identified as a result of newfound information."

Commenter (0323) states that "EPA should have provided updated guidance, new modeling, [and] instructions on corrections for specific state deficiencies." In a similar comment, commenter (0531) adds that the EPA has not given states ample opportunity to account for changes in air quality models and the EPA's new interpretations of guidance.

Commenter (0323) states that the EPA improperly asserts that its three 2015 Ozone NAAQS good neighbor SIP flexibility guidance memoranda should no longer be considered applicable to implementation of the good neighbor provisions. Commenter says in proposing this transport FIP, the EPA fails to acknowledge and implement the guidance it provided to states in 2018 to assist them in preparing their good neighbor SIPs. States relied upon the EPA's guidance at the time and were never reasonably informed of changed agency policy to allow them to respond and revise. The EPA has failed to extend the courtesy to the states an acknowledgment that its historic policies were no longer to be honored by the EPA nor cited by states.

The EPA had reason to know states would be relying on the three 2018 guidance documents to develop their good neighbor SIP submittals but failed to advise the states that the agency had changed its opinion about its guidance. Nineteen good neighbor SIPs were pending before the EPA awaiting the EPA review for three or more years since the EPA issued the 2018 good neighbor SIP guidance. Only one EPA review was proposed for action in March 2020. The EPA proposed approval of Iowa's good neighbor SIP that incorporated the 2018 guidance. 85 Fed. Reg. 12,232 (March 2, 2020). With the event of this proposed FIP, the EPA also is proposing to characterize these documents as archival in nature and to walk back the proposed Iowa approval (See, 87 Fed. Reg. 9,477, February 22, 2022).

Commenter (0340) notes that the EPA is proposing a FIP using newly updated modeling data, specifically the 2016v2 platform, which was not previously made available via the Notice of Data Availability (NODA) process and publication in the *Federal Register*. The commenter says on April 30, 2021, based on the 2016v1 modeling platform, the EPA published the final Revised Cross State Air Pollution Rule Update for the 2008 Ozone NAAQS, identifying two nonattainment receptors and one maintenance receptor as linked to Kentucky. Kentucky was not afforded the opportunity to evaluate the potential linkages or provide additional information regarding these potential linkages concerning the 2008 ozone NAAQS. Less than 12 months later, the EPA published the proposed rule addressing transport for the 2015 ozone NAAQS. In this proposed rule, the EPA has identified two new receptors (New Haven, Connecticut and Bucks County, Pennsylvania) as being impacted by Kentucky emissions, but not impacting the previously identified maintenance receptor (Madison, CT). The EPA identified these changes to linked downwind receptors using the 2016v2 modeling platform. However, Kentucky was not afforded the opportunity to evaluate the potential impact of emissions for the new areas prior to the EPA's proposal of a FIP.

Response:

These comments are responded to in Section III.B of the preamble. Comments regarding specific modeling issues are addressed in Section 3 of this document (EPA's Analysis of Downwind Air Quality Problems and Contributions from Upwind States) and in Section IV of the preamble.

1.1.3 SIP Call under 110(k)(5)

Comments:

Commenters (0336, 0340, 0400, 0500, 0542, 0557), overall, contend that the EPA should have issued a SIP Call rather than propos[ing] a FIP. Many of the commenters remark that section 110(k)(5) of the CAA directs the EPA to first require the states to develop SIP revisions as the means for attaining NAAQS and CAA requirements, including those in the good neighbor provision of the CAA, and it requires the EPA to give States a reasonable opportunity to develop their own SIPs, which some commenters believe the process lacks – *e.g.*, according to commenter (0542), the EPA issued the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards without providing the mandatory opportunity under CAA section 110(k)(5) for Mississippi to respond to the EPA's proposed SIP disapprovals or to submit a SIP to comply with the EPA's finding of significant contribution. Commenter (0336) adds that a SIP Call approach would be more in keeping with the CAA's state-federal partnership approach to meeting air quality goals. Commenter (0400) notes that while the CAA does not define “significant contribution” or “interference” and, as such, a State cannot choose controls to eliminate such emissions until the EPA quantifies the State’s reduction obligation, here, the EPA has proposed to simultaneously (a) disapprove SIPs; (b) define the State’s significant contribution; and (c) circumvent further consultation with the States via imposition of a FIP to abate it. The commenter maintains that instead, the EPA is obligated to first issue a SIP call under CAA section 110(k)(5). The commenter states that CAA section 110(k)(5) directs the EPA to first require the states to develop SIP revisions as the means for attaining the NAAQS and meeting CAA requirements. Moreover, CAA section 110(k)(5) requires the EPA to give States a reasonable opportunity to develop their own SIPs, with the possibility that CAA section 110(c) will necessitate the issuance of a FIP following a CAA section 110(k)(5) SIP call. The commenter says that the EPA immediately issued this rule without providing any opportunity under CAA section 110(k)(5) for a State to respond to the EPA’s proposed SIP disapprovals or to submit a SIP to comply with the EPA’s finding of significant contribution; furthermore, there will be no opportunity to replace the FIP with a revised SIP prior to the FIP’s effective date. The commenter writes that instead, the EPA is effectively telling states how to achieve SIP compliance and mandating adoption of a control scheme, without giving States the freedom to implement other measures in lieu of the ones identified by the EPA and without consideration of States’ individual interests.

Commenters (0336, 0340, 0400, 0500, 0542, 0557) comment that the EPA should have issued a SIP Call rather than proposed a FIP. Commenter (0336) adds that a SIP Call approach would be “more in keeping with the CAA’s state-federal partnership approach to meeting air quality goals.”

Response:

The EPA disagrees that the Agency is required to explain why it is not exercising its discretion under CAA section 110(k)(5), which allows the EPA to require a state “to revise the [SIP] as necessary” [w]henever the Administrator deems a SIP is “substantially inadequate to attain or maintain the relevant [NAAQS][.]” This “SIP call” authority is discretionary with the Agency, and nothing in the statute obligates the EPA to first provide states a second opportunity to submit approvable SIPs before promulgating FIPs. *See EME Homer City*, 572 U.S. at 509.

As a preliminary matter, commenters have not raised an issue that is actually within scope of the present action: EPA is promulgating a FIP pursuant to its authority under CAA section 110(c)(1), following its action disapproving relevant SIP submissions under CAA section 110(k)(3) or finding certain states failed to submit SIPs under CAA section 110(k)(1). This authority is not altered or displaced by the fact that the EPA has discretionary authority to issue a SIP call under CAA section 110(k)(5).[1]

Comments urging the Agency to issue a SIP call pursuant to CAA section 110(k)(5) are effectively requesting that the Agency engage in an additional rulemaking effort separate from this action. Without offering any final determination on that suggestion, which is beyond the scope of this action, such an approach could, if undertaken as an alternative to the present action, effectively cause a delay of several years in implementing good neighbor obligations for the 2015 ozone NAAQS. Thus, if this even were a reviewable question with respect to the Agency's action here, it is reasonable for the Agency not to embark on that course of action.

Commenters problematically prioritize giving states further opportunities to submit an approvable SIP before EPA promulgates a FIP, rather than prioritizing the statutory obligation to eliminate pollution significantly contributing to nonattainment and interfering with the NAAQS in other states as expeditiously as practicable. Commenters' policy preference is not required by the Act; importantly, it is in tension with the Act's substantive mandates. *See Wisconsin*, 938 F.3d at 316-18. It is appropriate for the Agency to not pursue a discretionary SIP call in the circumstances here, where expeditious action to address outstanding obligations is paramount, delay has already occurred, and the Agency seeks to address an area of CAA implementation (interstate air pollution at the regional scale) where the EPA historically has been obligated to exercise its FIP authority to achieve necessary emissions reductions.

The EPA does not rule out the possibility of using mechanisms such as CAA section 110(k)(5) or the promulgation of an obligations rule to inform states' development of transport SIPs for future NAAQS revisions or in other circumstances. In the context of this NAAQS, at this time, however, such an approach would further delay the implementation of good neighbor obligations that the courts have already found the EPA is past due in addressing. *See, e.g., Maryland v. EPA*, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020). Under the EPA's current sequencing of actions, upon finalization of this action, the EPA will be able to ensure emissions reductions to address good neighbor obligations beginning in the 2023 ozone season. By contrast, even under a relatively aggressive timetable for issuing a SIP call, these emissions reductions could be delayed by as much as three years or more. (This estimate takes into account the time needed to propose and finalize action issuing the SIP call, the time needed for states to develop, take comment on, and submit SIP revisions, the time needed for the EPA to

[1] We note as well that the EPA is obligated to promulgate certain FIPs in this action pursuant to a federal consent decree, which was entered to resolve litigation alleging that the EPA had already missed statutory deadlines pursuant to CAA section 110(c)(1). The EPA also has a statutory obligation as to all of the other states included in this action to promulgate FIPs within two years. The EPA is aware of no authority, and commenters cite none, that would authorize EPA not to meet its statutory obligation to promulgate FIPs and instead take the alternate course of issuing a SIP call under 110(k)(5). Thus, commenters have not explained how, even if the EPA issued a SIP call as a separate action in relation to good neighbor obligations for the 2015 ozone NAAQS, this would alter the schedule of actions it is obligated to undertake by virtue of 110(c)(1).

propose and finalize action on those SIP revisions, and the time needed to propose and promulgate a FIP, if necessary. *See, e.g.*, 74 FR 55292.)

During the time needed to implement a SIP call as commenters suggest, the EPA would have allowed significant contribution to continue through both the 2024 Moderate area attainment date and quite possibly the 2027 Serious area attainment date, missing not one but two critical attainment dates (the "ultimate failsafe" in the words of the *Wisconsin* court, 938 F.3d at 317) in implementing CAA obligations that are at "the heart of the Act," *id.* at 316 (quoting *Train v. NRDC*, 421 U.S. 60, 66 (1975)). The EPA would have been required to proceed through not one but two additional rulemaking efforts (both the SIP call, and actions on SIP submittals in response to the SIP call). And the EPA would have allowed this to occur even though, as the *Wisconsin* court also recognized,

> When EPA determines that 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. *See Sierra Club v. EPA*, 294 F.3d 155, 161 (D.C. Cir. 2002) ("the attainment deadlines remain intact" even if procedural deadlines are missed or changed). The same is true when a State's SIP fails to provide for the full elimination of the State's significant contributions to downwind nonattainment.

Id. at 318.

Consistent with the court's observations in this passage, under the EPA's approach, the EPA is able to take final action promulgating FIPs for the covered states before the start of the 2023 ozone season. By proposing FIPs in April of 2022, the EPA proactively put itself in a position to finalize these FIPs in time for the 2023 ozone season, thus beginning implementation of needed emissions reductions to eliminate significant contribution in the analytic year associated with the next relevant attainment date for the 2015 ozone NAAQS. See Section 3.1 (Years Selected for Analysis) for further discussion of the selection of analytic year. Further, with the proposal, the EPA was also able to put states and sources on notice of its proposed expectations regarding what level of emissions reductions would be needed to eliminate the amounts of emissions significantly contributing to nonattainment and interfering with maintenance. *See* 87 FR 20040, 20149-51. Following promulgation of this action, states may replace the FIP with a SIP so long as the substantive CAA obligations are achieved. This FIP provides a degree of information comparable to what the EPA would include in a SIP call in terms of identifying with specificity the level of emissions reductions each state would be expected to implement.[2] Thus, the EPA's approach does not even sacrifice the key benefit commenters apparently hope to achieve via a SIP call, which is a level of certainty for states regarding their good neighbor obligations to allow them to formulate approvable SIPs.

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[2] As discussed in the cited passage of the proposed FIP and in Section VI.D of the final rule preamble, the EPA always allows states the opportunity to implement a different mix of emissions controls than it has implemented through a FIP so long as the overall CAA obligation is met.

We reiterate that our reasoning as to the disadvantages of conducting a SIP call is not formally within the scope of this action and is offered simply to illustrate the disadvantages associated with this alternative sequence of steps advocated by commenters. We further acknowledge that there are many circumstances under the CAA where a SIP call may be an appropriate mechanism to ensure that the SIP complies with the CAA and that states are adequately fulfilling their CAA obligations to implement the NAAQS. The EPA has used this tool to address good neighbor obligations (as per the 1998 NO_X SIP Call[3]) and may do so again under appropriate circumstances in the future. However, there is nothing in the CAA that *requires* (much less authorizes) the agency to issue SIP calls instead of promulgating FIPs when the circumstances of CAA section 110(c)(1) are triggered. This irreducible statutory fact is not changed even if the EPA is accused of failing to issue guidance that was sufficiently clear or prescriptive to states before their original SIP submittals were due—the EPA has no such obligation. *See EME Homer City,* 572 U.S. at 508-11. Here, the importance of not further delaying necessary emissions reductions through attempting to defer the EPA's *mandatory* duties in preference for a *discretionary* SIP call is a reasonable course of action.

1.2 Authority to Establish Emissions Limits and Control Requirements

Comments:

Commenter (0798) continues, "no state has proposed the type, scope, or stringency of emissions limitations contained in the Proposed Rule. This is particularly notable in the context of the NAAQS, which do not require limitation of any particular industry, emissions source, or use of any particular control technology to achieve the interstate transport obligations of CAA § 110. This wholesale rejection not just of the states' findings, but their entire approach to regulating emissions within their borders, particularly when combined with the lack of any opportunity for the states to reasonably comment on the denials of their SIPs and amend them in light of EPA's perceived deficiencies, demonstrates a lack of deference to the fundamental principles of cooperative federalism embodied in the Clean Air Act and further cautions against EPA proceeding with the Proposed Rule."

Commenter (0543) writes that the principle of cooperative federalism can't be achieved when pollution from upwind states negatively impacts the environment of neighboring states.

Commenter asks the EPA to "honor the 'cooperative' in cooperative federalism" by providing oversight of state actions to ensure that NO_X emissions are reduced.

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[3] Notably, the NO_X SIP Call was judicially stayed by the D.C. Circuit Court of Appeals, and this led EPA to exercise its independent authority to directly federally regulate sources violating the good neighbor provision in response to petitions under CAA section 126(b), an action which that same court subsequently upheld. *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1039 (D.C. Cir. 2001).

Commenter (0547) writes that the proposed rule includes a "calibrated mix of federal and State roles, with emphasis on the States regulating within their respective boundaries" which "reflects the CAA's goal of establishing a system of cooperative federalism" by "placing the primary responsibility for preventing and controlling air pollution with the states and local governments."

Commenters (0512, 0550, 0551, 0798) argue that the EPA has identified no legal basis for imposing emissions unit specific limits on any of the individual non-EGU emissions units in the proposed rule. The commenters maintain that the EPA cannot dictate how a state implements CAA section 110(a)(2)(D)(i)(I) – *i.e.*, the EPA's authority granted under the good neighbor provisions is limited to ". . . any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard." The commenters clarify that the EPA can, at most, determine what overall emissions tonnage level a state must achieve; however, they may not go beyond the scope of that good neighbor provision and impose any unit-specific rules or requirements. Commenter (0551) recommends that the EPA clarify in the final rule that states are not obligated to include (in their SIPs) the proposed emissions rate limits and should provide states with overall emissions targets that states can achieve in any manner they deem appropriate.

Commenter (0550) believes that the EPA fundamentally disregarded the language of CAA section 110(a)(2)(D)(i) in an attempt to implement a technology-forcing scheme. The commenter states that CAA section 110(a)(2)(D)(i) is not written as a technology-forcing provision, rather its focus is on improving ambient air quality, but despite this, the EPA's ultimate goal under the proposed rule is to mandate sources to operate certain controls in a certain manner; not to achieve the CAA's ambient air goals. The commenter further argues that the approach taken by the Agency – insisting that certain controls "are necessary" reflects a material misrepresentation of the CAA's mandate under section 110(a)(2)(D)(i). The commenter notes that rather than directing states to require the operation of any particular control technology, as Congress did in many other sections of the CAA, section 110(a)(2)(D)(i) focuses on ambient air and does not mandate the use of any particular level of emissions control (*e.g.*, "best available control technology" or "reasonably available control technology" [RACT]). The commenter says that as long as emissions from a state are reduced to a level at which they do not "contribute significantly" to downwind nonattainment or interference with maintenance of the NAAQS, it is irrelevant how such reductions are made. In addition, the commenter notes that if those reductions are to be achieved through a requirement to meet a certain emissions limit, then they must be justified on that basis. More specifically, the commenter states that the EPA cannot use the proposed rule to force particular control technologies on units without assessing its proposal in that light – instead of relying solely on the prior analysis of other, dissimilar trading rules. The commenter points to prior trading rules, noting that the EPA justified an "amount" of emissions reduction through an analysis of the region-wide cost of operation of controls but did not mandate such operations or the achievement of any source-specific emissions limit.

Commenter (0798) states that the EPA does not have the authority to mandate emissions limits by disapproving adequate SIPs and imposing its own FIP. The commenter says that in *Train v. NRDC*, 412 U.S. 60, 79 (1975), the U.S. Supreme Court made it clear that states have the authority under the CAA to develop the specific emissions limitations that will ensure compliance with the NAAQS in the first instance. As the Court later stated in *Union Elec. Co. v. EPA*, "Congress plainly left with the States, so long as the national standards were met, the power to determine which sources would be burdened by regulation and to what extent." 427 U.S. 246, 269 (1976); see also id. at 267 (states have "virtually absolute power in allocating emissions limitations so long as the national standards are met"). The commenter also noted that in light of the Supreme Court's holdings, the D.C. Circuit has held that the validity of the EPA's NAAQS program "depends in part on whether the program in effect constitutes an EPA-imposed control measure or emissions limitation triggering the *Train-Virginia* federalism bar: in other words, on whether the program constitutes an impermissible source-specific means rather than a permissible end goal." *Michigan v. EPA*, 213 F.3d 663, 687 (D.C. Cir. 2000) (internal alterations omitted). According to the commenter, in denying SIPs that adequately prevented significant contribution to nonattainment and interference with the NAAQS and supplanting these state-level approaches with a FIP that imposes the EPA's preferred method of achieving the same goal, the EPA's proposed rule supplants the states' role as primary decider of which sources to regulate and to what extent. The commenter asserts that this violates the federalism bar established in Train and Virginia v. EPA.

Commenter (0400) asserts that the proposed rule conflicts with CAA precedent. The commenter says the D.C. Circuit has held that the EPA under the CAA cannot "commandeer the regulatory powers of the states." It also conflicts with the D.C. Circuit's good neighbor precedent, which confirms that "EPA does not tell the states how to achieve SIP compliance" but rather the EPA "looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms." In *Michigan*, the court noted that the EPA "made clear that states do not have to adopt the control scheme that the EPA assumed for budget-setting purposes" because the EPA had "allow[ed] reasonable control alternatives and allow[ed] states to focus reduction efforts based on local needs or preferences." In the NO_X SIP Call, the EPA explained that its approach is consistent with its broader role under CAA section 110. The D.C. Circuit agreed, confirming that CAA section 110 leaves to the states "the power to [initially] determine which sources would be burdened by regulation to what extent." The EPA's NO_X emissions budgets, according to the court in that case, left the states with "real choice" regarding how to comply with the rule and because the states could "choose from a myriad of reasonably cost-effective options to achieve the assigned reduction levels." This stands in stark contrast to the deviation from precedent seen in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.

Commenter (0547) specifies that while, under the CAA, the EPA may assume the role of regulator and promulgate a FIP, this action can only be done if a state has not complied with the requirements of the "good neighbor" provision, and even then, the EPA's authority is constrained by the text/language of the "good neighbor" provision, the CAA's cooperative federalism mandate, and judicial precedent. More specifically, the commenter notes that courts interpreting the "good neighbor" provision have confirmed that the EPA's FIP will pass judicial muster only if it (a) respects the state's freedom to select whatever mix of emissions limitations the state deems best suited to its particular situation; (b) avoids impermissible, mandatory source-specific means of implementation; and (c) provides the state real choice with regard to the control measure options available to meet the budget requirements. The commenter maintains that agencies, like the EPA may fill in statutory gaps with "judgments of degree," [*Whitman*, 531 U.S. at 475] but they may not set "the criteria against which to measure" their own decisions [*Gundy*, 139 S. Ct. at 2141 (Gorsuch, J., dissenting)]; instead, they must act within the "sufficiently definite and precise" statutory authority set forth by Congress.

Response:

These comments are responded to in Section III.B of the preamble.

1.3 Authority to Regulate Power Sector Emissions

Comments:

Commenter (0306) states that "so long as Texas complies with the CAA, it should be free to adopt its own mix of emissions controls that it determines right for itself and its citizens." Commenter objects to Texas being included in the EGU cap-and-trade program despite submitting a statutorily compliant SIP.

In general, commenters (0372, 0395, 400, 0409, 0550) believe that the EPA's proposed FIP goes beyond the authority it has been granted, under the CAA. Specifically, commenters (0372, 0409) question the EPA's application of sections 110(c) and 301(a)(1) and whether the CAA grants the Agency the power/authority to propose, what the commenter (0372) argues, is an expansive rule. The commenters claim that the Agency does not explain why the CAA "compels" the actions in the proposed FIP. The commenters recognize that CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within two years after they: (1) find a state has failed to make a required SIP submission; (2) find a SIP submission incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapprove a SIP submission; and adds that the proposed FIP states that the EPA may use sections 110(c) and 301(a)(1) to employ a federal plan. However, the commenters disagree that these provisions, including CAA section 301(a)(1) grant the EPA unending power, which according to the commenter (0372), could change our country's power generation mix in the short time frame of four years. The commenters urge the Agency to withdraw the proposed rule.

Response:

The EPA is authorized under CAA section 110(a)(2)(D)(i)(I) and 110(c)(1) to directly regulate "any source or other type of emissions activity" whose emissions will significantly contribute to nonattainment or interfere with maintenance of the NAAQS in another state. This language is not limited to a particular category or size of sources or emissions activity and includes the power to regulate emissions from relatively large fossil-fuel fired EGUs in the power sector and other large stationary industrial sources of ozone-precursor emissions. *Cf. Wisconsin v. EPA*, 938 F.3d 303, 323 ("[a]ssuming without deciding that the good neighbor provision authorizes EPA to regulate only human-caused emissions," because the EPA did not contest the assertion but no party cited authority for it). In fact, each of the EPA's major 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).[4] The scope of sources the EPA and states can address under the good neighbor provision also includes sources in industrial sectors, and the EPA and states have done so before, in the NO_X SIP Call, *see* 63 FR 57365.

The EPA has established predicate authority to promulgate a FIP to implement the good neighbor provision for the 2015 ozone NAAQS for the covered states, through either disapproving SIP submittals or finding that certain states failed to make complete submittals. See Section III.B.2 of the preamble. This action is indeed "compelled" by the CAA, which mandates that the EPA must promulgate a FIP within two years of disapproving a SIP or making a finding of failure to submit. *See* CAA section 110(c)(1). The EPA is also obligated to address these obligations as expeditiously as practicable, and to the extent possible, by the next attainment date. *See Wisconsin*, 938 F.3d at 318 ("When EPA determines that a State's SIP is inadequate, the 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.").

The EPA is not asserting "unending" power, but rather is applying its traditional 4-step interstate transport framework of analysis for addressing interstate ozone transport based on the most recent information and for the more protective 2015 ozone NAAQS. The EPA's framework takes into account cost, among other things, and the EPA has ensured that the rule is feasible to implement, taking into account the time needed to install the relevant emissions controls. See Section VI.A of the preamble. The EPA may not "overcontrol" in promulgating a FIP to address good neighbor obligations (*i.e.,* require a more stringent control strategy than necessary to eliminate significant contribution and interference with maintenance), and the EPA has demonstrated that it has not done so. See Section V.D.4 of the preamble. Finally, all of the emissions-control strategies in this final action, for both EGU and non-EGU sources, are based on proven emissions-control technologies that have been available and implemented in downwind areas and/or previously mandated or implemented for similar sources under other provisions of the Act. See Section V of the preamble for further discussion of the bases for the EPA's emissions control determinations.

1.3.1 Relationship to other Federal Agencies

[4] *See also* Final Response to Petition From New Jersey Regarding SO_2 Emissions from the Portland Generating Station, 76 FR 69052, 69063-64 (Nov. 7, 2011) (establishing unit-specific emissions limitations at EGUs to eliminate significant contribution under CAA section 126).

Comments:

Overall, commenters (0306, 0346, 0372, 0395, 0400, 0409) maintain that the proposed rule ignores congressionally granted authority allotted to other agencies to manage energy sector issues at the peril of grid instability. The commenters recommend that the EPA withdraw the proposed rule because it extends beyond its authority.

More specifically, commenters (0346, 0395, 0409) mention that the Federal Energy Regulatory Commission (FERC) regulates interstate energy policy as part of the Energy Policy Act of 2005; adding that Congress delegated FERC the responsibility of protecting reliability and cybersecurity of the Bulk-Power System via the establishment and enforcement of mandatory reliability standards. Commenters (0346, 0409) claim, in general, that the proposed rule "provides EPA with the power to significantly impact national electricity and energy markets across state lines" and thus usurps FERC's jurisdiction and delegated authority to North American Electric Reliability Corporation (NERC) without consulting either entity during the development of the rule. Commenter (0409) also mentions that the Agency did not consult with FERC or NERC during development of the proposed rule.

Commenter (0395) writes that the proposed rule exceeds the EPA's statutory authority since EPA only has the powers specifically assigned to it by statute. Commenter says that the proposed rule would "restructure the electric grid," which goes beyond the powers delineated to the EPA in CAA section 110(a)(2)(D). Commenter adds federal authority concerning the energy sector was specifically given to other agencies under the Federal Power Act (FPA). And even under the FPA, federal agencies' authority over the energy sector is limited, with important aspects such as choice over generation mix reserved to the states. As such, the EPA's proposed rule not only goes beyond the authority it has been granted, but beyond the authority any federal agency has been granted.

Response:

These comments are responded to in Sections III.B.1.c and VI.B of the preamble.

1.3.2 Relationship to State Authorities

Comments:

Commenters (0306, 0346, 0362 0372, 0395, 0400, 0409, 0547) are expressly concerned that the proposed rule would upend traditional state and federal roles in tackling NAAQS compliance and, in violation of the CAA, alter the nation's energy supply – *e.g.,* result in substantial modifications to the U.S. energy supply sector and significantly impact grid reliability for 84 million Americans. Commenter (0346) adds that this rule will significantly change the power generation sector by:

- Requiring a change of generation mix in the short time frame of four years;
- Forcing the retirements of numerous coal-fired units due to selective catalytic reduction (SCR) installations in 2026 on less controlled units;

- Limiting the capacity factor of SCR-controlled coal units due to severely constrained budgets;
- Further reducing state budgets beginning in 2024 through "dynamic" budget setting; and
- Forcing the development and construction of new generation to meet power sector demand increases, because existing fossil fuel generation is limited by state budgets.

Commenter (0306) believes that the EPA's proposals within the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

unconstitutionally infringe on Texas's sovereign powers and attempts to seize authority held by the legislative branch and other regulatory agencies.

Commenters (0362, 0365, 0395, 0798) state, in general, that it was unreasonable and unlawful for the EPA to disapprove state SIP submissions, while concurrently issuing a proposed rule, particularly (as stated by commenter 0798) when disapprovals are based on data that the Agency fail[s] to generate until after its statutory deadline to act. While the commenter (0798) acknowledges that the D.C. Circuit has held that the EPA has legal authority to propose a FIP at the same time it disapproves a SIP submission without giving the state an opportunity to fix the deficiency in the SIP submission, the commenter is unaware of a decision or statutory basis that would allow the EPA to do so based on data that was unavailable to the state at the time that it made its SIP submission. [Note: Additional remarks pertaining to the EPA authority and state SIP submissions are discussed further in Section 2.4. FIP Authority (Timing and SIP Disapproval).

Commenter (0372) suggests that the lack of delegation is further supported by the absence of any guidance or standard from Congress to the EPA. The commenter says that when delegating authority to an agency, Congress must provide some guidance, standard, or guardrail within which the agency may act; adding that the Constitution bars Congress from giving "literally no guidance" or overly vague standards when conferring agency power [*Whitman v. American Trucking Associations*, 531 U.S. 457, 474 (2001)].

Commenters (0372, 0395) briefly discuss being regulated at the state level and conclude, in general, that neither the EPA nor any other federal agency has authority to demand or require of these state entities the actions the EPA is proposing. Commenter (0372) notes that utilities in Kentucky are regulated by Kentucky Public Service Commission, in addition to also being regulated by NERC, as delegated by FERC to sustain reliability.

Commenter (0395) states that Texas's primary grid, the Electric Reliability Council of Texas (ERCOT) control area, is an intrastate grid, and thus the federal government does not have jurisdiction even over transmission services and wholesale electricity prices within ERCOT. The commenter says that the independent system operator of that grid, ERCOT, is subject to oversight and regulation by the Public Utility Commission of Texas (PUCT) and the Texas Legislature. The commenter concludes that neither the EPA, nor any other federal agency has authority to demand or require of these state entities the actions the EPA is proposing. The commenter argues, to the contrary, federal authority extends only to the transmission and sale of wholesale electricity in interstate commerce. Importantly, the EPA is not the federal agency with authority over the transmission of electricity, including grid reliability. In fact, "EPA has no expertise on grid reliability—its sister agency FERC, uninvolved in this regulatory scheme or this rulemaking, is the federal expert in that area." Moreover, federal jurisdiction over Texas is even more limited because "[i]n its electrical grid…Texas stands alone." Texas's primary grid, the ERCOT control area, is an intrastate grid, and thus the federal government does not have jurisdiction even over transmission services and wholesale electricity prices within ERCOT. The independent system operator of that grid, ERCOT, is subject to oversight and regulation by the PUCT and the Texas Legislature. Neither EPA nor any other federal agency has authority to demand or require of these state entities the actions EPA is proposing."

Commenter (0372) claims there are possible dangers associated with having multiple agencies oversee common areas/topics, like energy and reliability, and compares the Energy Information Administration's (EIA) projections and Integrated Planning Model (IPM) results as an example; noting that Congress, luckily, makes final congressional authorization.

Commenters (0395, 0547) believe states should retain "traditional authority over the need for additional generating capacity, the type of generating facilities to be licensed, land use, ratemaking, and the like," and suggests that the EPA cannot rely on CAA section 110 as a vehicle for implementing policy preferences – *e.g.*, determining the "amount" of emissions reductions are needed by a state to meet "good neighbor" obligations, because the "good neighbor" provision does not authorize EPA to intrude on areas of traditional state authority, such as a state's generation mix, nor does CAA section 110 compel the EPA to define "amounts" in a manner that accomplishes little or nothing for air quality. The commenters state that, while CAA section 110 obligates states to reduce a certain gross amount of offending emissions, they have some discretion over how to reasonably define that "amount;" consequently, the proposed rule interferes directly with the states' generation choices. Commenter (0395) underscores the point that nothing in CAA section 110 converts this tailored role into a sweeping authority to restructure the generation mix of each state through generation shifting or early retirements.

Commenter (0400) asserts that the proposed rule conflicts with CAA precedent. The commenter says the D.C. Circuit has held that the EPA under the CAA cannot "commandeer the regulatory powers of the states." It also conflicts with the D.C. Circuit's good neighbor precedent, which confirms that "EPA does not tell the states how to achieve SIP compliance" but rather the EPA "looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms." In *Michigan*, the court noted that the EPA "made clear that states do not have to adopt the control scheme that the EPA assumed for budget-setting purposes" because the EPA had "allow[ed] reasonable control alternatives and allow[ed] states to focus reduction efforts based on local needs or preferences." In the NO_X SIP Call, the EPA explained that its approach is consistent with its broader role under CAA section 110. The D.C. Circuit agreed, confirming that CAA section 110 leaves to the states "the power to [initially] determine which sources would be burdened by regulation to what extent." The EPA's NO_X emissions budgets, according to the court in that case, left the states with "real choice" regarding how to comply with the rule and because the states could "choose from a myriad of reasonably cost-effective options to achieve the assigned reduction levels." This stands in stark contrast to the deviation from precedent seen in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.

Commenter (0542) writes that "EPA's actions have assured that Mississippi will have no opportunity to replace the FIP with a revised SIP prior to the FIP's effective date. In so doing, the EPA is usurping state authority and mandating to states how they must achieve compliance without giving states the freedom to implement measures other than those chosen by the EPA. The EPA's approach conflicts with CAA precedent: The D.C. Circuit has held that the EPA under the CAA cannot "commandeer the regulatory powers of the states." It also conflicts with the D.C. Circuit's good neighbor precedent, which confirms that "EPA does not tell the states how to achieve SIP compliance" but rather the EPA "looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms." Commenter continues, "EPA has given Mississippi and other states no choice in the implementation of the Transport Rule FIP. Rather than allowing states to develop their own compliance strategies, the EPA made those choices for them. In violation of the CAA and related case law, the EPA has unlawfully commandeered the states' discretion to address good neighbor obligations in a manner of its choosing. The EPA's actions here represent the exact opposite of cooperative federalism. The EPA should have issued a SIP call and provided states a "reasonable deadline" for submission of plan revisions upon findings of inadequacies rather than dictating its own choices for compliance with section 110 of the Clean Air Act."

Response:

This rule does not interfere with authorities reserved to the states under the FPA or other laws to make determinations regarding their sources of electricity generation. It implements an emissions control program for power plants and industrial sources applying the EPA's longstanding 4-step interstate transport framework for implementing the good neighbor provision, which has been upheld in fundamental respects by multiple decisions of the D.C. Circuit and the U.S. Supreme Court.

The enhancements to the CSAPR trading program model are discussed in Section VI.B of the preamble. The EPA's response to comments on these topics as well as our response on issues of "grid reliability" are also addressed in that section.

The EPA is not forcing the retirements of coal-fired units; installing conventional pollution control technology like SCR is a viable means of compliance. Nor by the same token is the EPA forcing the development and construction of new generation. The claim that the EPA is "limiting the capacity factor of SCR-controlled coal units due to severely constrained budgets" is unexplained. The process by which the EPA has set the budgets is explained in Section VI.B.4 of the preamble.

The EPA disagrees that it lacks authority to regulate emissions from EGUs that are alleged to be part of a wholly intrastate transmission grid or subject to oversight by state utility regulators. The EPA is regulating the interstate effects of pollution from such sources as authorized under CAA section 110(a)(2)(D)(i)(I).

The EPA's authority to directly regulate emissions sources through FIPs under CAA section 110(c)(1) is addressed in Section 1.2 (Authority to Establish Emissions Limits and Control

Requirements). The EPA's authority to regulate emissions from fossil-fuel fired EGUs is addressed in Section 1.3 (Authority to Regulate Power Sector Emissions). The comments from and consultation with grid reliability authorities related to this rule are discussed in Section VI.B.1 of the preamble.[5] The air quality benefits of the rule are described in Section V.D of the preamble.

In regard to comment suggesting it is problematic for the government to have multiple entities (EIA and EPA) and multiple models (AEO and IPM) analyzing the power sector, we note that the two resources cited are complements to one another and serve different functions. The two government agencies engage in regular communication, coordination, and shared data in the underlying model structures. IPM is periodically peer-reviewed and found to be specifically appropriate for regulatory modeling.

1.3.3 Expertise Regarding Grid Reliability

Comments:

Commenters (0395, 0400, 0500) directly mention the point that the EPA has no expertise on grid reliability; adding that its sister agency, FERC, which the commenters claim has been uninvolved in this regulatory scheme or this rulemaking, is the federal expert in that area. Commenter (0395) continues to emphasize that federal authority extends only to the transmission and sale of wholesale electricity in interstate commerce, and importantly, the EPA is not the federal agency with authority over the transmission of electricity, including grid reliability.

Commenters (0327, 0400, 0912L) express concern about the lack of consultation with the Regional Transmission Organization (RTOs) regarding the impacts of the proposed rule on electric reliability.

Commenter (0400) further underscores the point that the EPA has not coordinated with [the] appropriate parties (FERC, NERC, RTOs, or States) regarding energy reliability impacts of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, and along with commenter 0550 maintain that the Agency [has] surpassed its authority granted to them by the Congress under the CAA [by overseeing] the regulation of utilities [that] is traditionally associated with the police power of the States – without any meaningful evaluation of grid reliability concerns.

Response:

The EPA disagrees that it lacks the necessary expertise to regulate emissions from fossil-fuel

[5] EPA has also included in the docket for this action memoranda memorializing these meetings.

fired EGUs in a manner that is compatible with ensuring grid reliability. While grid-reliability matters are more squarely within the domain of other federal agencies like FERC and the Department of Energy (DOE), the EPA has successfully regulated power sector emissions under multiple CAA programs since the modern Act was passed in 1970, with little to no impact on the ability of utilities and grid operators to deliver safe, affordable, reliable electrical power. Throughout this history, the EPA has demonstrated an understanding of how the interconnected electric generating system functions and has taken these characteristics into account in its design of regulations to reduce EGU emissions.

For example, in one of the EPA's earliest actions directly regulating EGUs, in 1979, the EPA finalized new standards of performance to limit emissions of sulfur dioxide, particulate matter, and nitrogen oxides from new, modified, and reconstructed EGUs.[6] Notably, in assessing the best demonstrated system against concerns of electric service reliability, the EPA took into account "the generating capacity of the affected utility company . . . , and the amount of power that could be purchased from neighboring interconnected utility companies." 44 FR at 33597. Part of this analysis noted that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations." *Id.* at 33599. Thus, the EPA determined that a broad exemption from the standards was not necessary to address emissions control outages or reductions in removal efficiency, "because load can usually be shifted to other electric generating units." *Id.* at 33600. Accordingly, an exemption from the standards was "not necessary to protect electric service reliability or to maintain compliance with the[] SO_2 standards." *Id.* These standards were upheld by the D.C. Circuit in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). *See also, e.g.,* 47 FR 3767, 3768 (Jan. 27, 1982) (evaluating the different operating needs and considerations for industrial turbines versus turbines used for electricity generation).

Within the history of our regulatory programs addressing interstate transport, the EPA has successfully implemented EGU emissions reductions while considering the unique characteristics and capabilities of the interconnected grid. *See, e.g.,* CSAPR, 76 FR at 48272. These issues were not the subject of the petitions for judicial review of CSAPR, but the CSAPR program overall was upheld in *EME Homer City*, 572 U.S. 489, *on remand*, 795 F.3d 118.

The EPA's record-based determinations regarding the implementation of further ozone-season NO_X reductions from EGUs in the CSAPR Update were the subject of petitions for review in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019). The EPA was uniformly upheld in these determinations against both "downwind" and "upwind" challengers. The EPA was upheld in its determination of the emissions rate existing EGUs with SCR could achieve on a fleetwide basis, 938 F.3d at 320-21. The EPA was upheld in applying a limited amount of generation shifting in the budget-setting process to ensure emissions control operation was adequately incentivized while constraining the degree of generation shifting to respect "near-term technological feasibility," *id.* at 321. The EPA was upheld in allowing for the carry-over of a

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[6] *See* New Stationary Sources Performance Standards; Electric Utility Steam Generating Units, 44 FR 33580 (June 11, 1979).

bank of emissions allowances converted from the prior CSAPR ozone season trading program to balance the need to maintain budget stringency while continuing to incentivize reductions under the prior program, *id.* at 321.

Regarding challenges brought by the electric utility industry, the EPA was upheld in its determinations that combustion controls could be upgraded within eight months, *id.* at 330. The EPA was upheld in its treatment of units that were modeled to "idle" in response to the CSAPR Update:

> To capture actual market mechanics, the model determines the least-cost method of anticipating electricity demand over a given period, and it assumes that less efficient units will be "idled" in the short run when they are not needed to meet demand. That temporary, on-again-off-again idling is quite distinct from permanent retirement and closure of a facility. That a model overestimates the rate of long-run retirements thus says nothing about whether it accurately projects the ebb and flow of short-run supply and demand. So, EPA's decision to limit near-term retirement projections based on long-run unprofitability says nothing about the use of temporary, market-driven idling in its economic models.

Id. EPA was upheld in its assignment of emissions rates to calculate the budgets and its treatment of EGUs with combined stacks, *id.* at 330-31. The EPA was also upheld in the use of its own data for EGUs as required to be reported to the EPA under 40 CFR part 75, rather than less reliable data based only on estimations, which are maintained by the U.S. Energy Information Administration.

> In setting that cap, EPA relied principally upon measured data reported directly by industry to the agency under 40 C.F.R. part 75, subpart G. "Where EPA data [were] unavailable," the agency said it would also rely on data from the United States Energy Information Administration. . . . EPA reasonably prioritized its own data, which "relies on unmodified historic data reported directly by the vast majority of covered sources, whose designated representatives have already attested to [its] validity." 76 Fed. Reg. at 48,288. In deciding whether to use the Energy Information Administration's estimates to fill in the gaps, EPA faced a tradeoff between accuracy, on the one hand, and long-run representativeness, on the other. We see no reason to disturb the balance that EPA struck.

Id. at 333-34.

Finally, the EPA was upheld in its treatment of new and existing EGUs for purposes of making allowance allocations. In particular, the court credited the EPA's concern that it not disincentivize through its allowance allocation methodology the retirement of older units that might otherwise retire:

> This five-year-long dormancy requirement was necessary because a sudden loss of allowances might "cause a unit, which would otherwise retire, to continue operations to retain ongoing allowance allocations." . . . And a set aside for retiring units was necessary to ensure that the allowance allocations did not have the perverse incentive of deterring retirement.

Id. at 334-35.

These holdings from the *Wisconsin* decision amply demonstrate the Agency's competency and capabilities in implementing the good neighbor provision to reduce EGU emissions while not interfering with the functioning of the interconnected grid or electricity markets. Indeed, following the remand of the CSAPR Update on other grounds in *Wisconsin*, the EPA found in the Revised CSAPR Update that even greater emissions reductions from EGUs were available and could be implemented rapidly to ensure a full remedy to interstate ozone transport for the 2008 ozone NAAQS. *See* 86 FR 20036, 23087-97, 23100-103.

Just as the EPA was upheld in making a host of similar determinations regarding the design and implementation of the Group 2 ozone season NO_X trading program in the CSAPR Update in *Wisconsin*, the EPA is confident in its record-based determinations, informed by public notice and comment, regarding the achievability of the emissions budgets and other trading-program requirements being finalized for EGUs. See Section VI.B.1.d of the preamble for further discussion of our consideration of grid-reliability issues.

1.3.4 Authority to Require Generation Shifting

Comments:

Commenters (0300, 0306, 0323, 0333, 0342, 0365, 0385, 0395, 0409, 0505, 0528, 0541), in general, state the FIP is unlawfully forcing generation shifting. Several commenters point out that the authority over wholesale electric markets is the sole province of state public utility commissions, except where the FPA authorizes FERC regulation. Environmental regulation has been limited to specific requirements on specific power plants and has never been interpreted to grant the EPA broad authority to favor one generation source over another. At least one commenter (0333) notes that requirements of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, including mandated retirement of EGUs without SCR technology by 2026, (or the infeasibility of installing SCR technology by 2026 for those EGUS considering this option), dynamic emissions budgets, reductions in NO_X allowances, and backstop daily NO_X limits, will leave many EGU owners no choice but to retire their units. Given the scope and effect of these retirements, this rule is essentially dictating the type and amount of electric generation in the states affected by this rule. The commenter states that the EPA's proposed Clean Power Plan (CPP)was an attempt to seize jurisdiction from state public utility commissions regarding the planning, operation and resource decisions made in electricity markets.

Commenter (0300) states that managing generation shifting is contrary to the spirit and rule of the CAA. Congress did not intend to give EPA an overreaching authority to shape the way power is generated or to mandate generation shifting. Likewise, Commenter (0323) states that the EPA's reliance on generation shifting as a control mechanism under the good neighbor provisions of the CAA is arbitrary and capricious and otherwise exceeds its legal authority.

Similarly, commenters (0306, 0342, 0365) say that the EPA inappropriately and without authority requires the consideration of electric generation shifting as a control mechanism in addition to requiring new or optimized NO_X controls. They say that these provisions put even more strain on an already strained electric grid. Commenter (0365) reiterates the point that the

EPA should not rely on generation shifting as a way to reduce emissions, because the FERC is under the DOE, and it regulates the interstate transmission of electricity, natural gas, and oil.

Commenters (0306, 0400) claim emissions budgets are infeasible and (along with commenter 0385) assert that the proposed FIP, as written, will result in generation shifting – an unauthorized extension of the EPA's limited authority under the good neighbor provision, which commenter (0385) contends disproportionately impacts single-site cooperatives. Commenter (0400) provides a brief description of the EPA's typical cap-and-trade approach, which is designed to achieve emissions reductions at the lowest cost by providing compliance flexibility and says that the reduction of allowances in the program will essentially end the use of trading as a compliance alternative and either force technology installation or generation shifting. The commenter suggests that by compelling generation shifting, the EPA is inappropriately directing energy policy that should be the province of the states and/or other federal agencies (*e.g.*, FERC). The commenter adds that generation shifting will not be available to all utilities, which could force shutdowns, and it is inconsistent with the EPA's 4-step interstate transport framework because it is not federally enforceable under Step 4.

Commenters (0349, 0361) argue that the EPA is incorrect in claiming that generation shifting is both technically and legally authorized under the Clean Air Act. Commenter (0349) submits that the EPA's conclusion that generation shifting poses no conflict to FERC or state jurisdictions under the FPA is incorrect, and the legal issues surrounding the concept of generation shifting are thoroughly presented in the Affordable Clean Energy (ACE) litigation pending before the U.S. Supreme Court of Appeals, WV v. EPA, Case Nos. 20-1530, 20-1531, 20-1778 and 20-1780 (also noted by commenter 0361). Commenter (0349) notes that the petitioners in that litigation have presented a challenge to generation shifting as a regulatory action, arguing that agency-enforced generation shifting away from coal is a major question that implicates hundreds of billions of dollars, tens of thousands of potentially regulated parties, and years of congressional wrangling. The commenter adds that similar to the dilemma presented in the ACE litigation is the concern that the EPA has improperly invoked CAA §110, resulting in an imbalance between upwind and downwind states' obligations to develop SIPs for the 2015 ozone NAAQS. The commenter states that the EPA's proposed generation shifting assumptions of the FIP and prior proposed denials of good neighbor SIPs are rife with unresolved legal issues and technical complexity. The commenter states that the EPA's FIP has the impact of changing power generation to the point of changing the energy economy, and the EPA has failed to recognize the role of the RTOs with respect to grid reliability. Further, the commenter asserts that the EPA fails to recognize that grid reliability obligations have no artificial state borders, and that any generation "shifting" is tantamount to exacerbating current and material grid reliability issues. The commenter claims that in some cases, this proposed rule could force EGUs to either close or transition to seasonal operations based on a legal and technical rationale that is not supported in law.

Commenter (0558) does not believe EPA has reasonably scrutinized the specific impacts of imposing its trading budget allowances on Delaware sources. The commenter is concerned that the proposed rule may have the unintended effect of shifting power generation to sources with fewer controls, which have the potential for higher ozone season emissions. The commenter adds that when a facility's emissions are addressed with a cap, imposing provisions on individual units is unlikely to result in reduced emissions overall.

Response:

Commenters' arguments regarding generation shifting as an emissions control strategy are addressed in Section V.B.1.f of the preamble.

We note that generation shifting is not included as part of the emissions control strategy for EGUs in Step 3, but is an available method of compliance within the emissions trading program. The economic analysis of the rule in the RIA also recognizes that the final rule policy may lead some facilities to make an economic decision to retire an EGU. But any emissions limit or enforceable control program under the CAA that is premised on the implementation of some kind of pollution control technology could be viewed as effectively requiring the installation and operation of that technology (or complying with the emissions limitation by achieving an equivalent degree of emissions reduction by some alternative method), or the cessation in operations of that facility. *See, e.g.*, CAA section 126(c) (requiring sources subject to a granted petition under CAA section 126(b) to cease operating or to come into compliance with the EPA's emissions limitations and compliance schedules within no later than three years). The EPA's determination in this action is that, for certain fossil-fuel fired EGUs, a reduction in emissions associated with the retrofit of SCR technology is necessary to eliminate significant contribution. The program provides flexibility for sources that do not wish to install that control technology, so long as the overall emissions budgets and other requirements are met.

And the EPA has deferred the imposition of the backstop emissions rate until 2030, reflecting industry commenters' request to have greater flexibility in determining how to comply with the rule for units that will retire by 2030 and to effectuate an efficient power sector transition to less polluting forms of electricity production.

Commenter's concern regarding Delaware is mooted because Delaware is no longer included in the final rule. Commenter's broader concern about the potential that this rule would cause generation to shift to sources that are less well controlled for NO_X is addressed in Section 5.2 (Regulatory Requirements for EGUs).

1.4 Authority for Trading Program Enhancements

Comments:

At large, commenters (0286, 0346, 0366, 0394, 0400, 0512, 0519, 0554) maintain that the EPA does not have the authority, under the "good neighbor" provision, to require one or more of the proposed enhancements (*i.e.*, dynamic budgeting, the daily backstop rate, annual banking recalibration, and electricity generation shifting).

Commenters (0346, 0400) assert that the "good neighbor" provision does not permit the EPA to compel installation of SCR control technology through imposition of a daily "backstop" emissions limit. While the commenters acknowledge that Congress authorized the EPA to set technology-based emissions limits in certain parts of the CAA , such as parts C (prevention of significant deterioration (PSD)) and D (nonattainment new source review (NNSR)) of Title I, the commenters claim that the Agency has not been authorized to set technology-based emissions limits under part A of Title I, in particular CAA section 110's "good neighbor" provision. The commenters suggest that the proposed "enhancements" are illegal; explaining that part A's "good neighbor" provision requires upwind states to eliminate their significant contributions to downwind pollution "consistent with the provisions of this subchapter"—referring to Title I, which includes the construction permitting program in parts C and D, but in establishing a backstop emissions limit that compels installation of control technology, the EPA is (mis)using the "good neighbor" program (part A) by converting it into a new source review (NSR) construction permitting program (part C or D). Commenter (0400) further adds that by extending a construction permitting requirement into the "good neighbor" provision, the EPA is essentially extending nonattainment areas and construction permitting requirements in downwind states into upwind attainment areas.

Commenter (0366) states that the EPA failed to explain how the proposed dynamic budgeting process meets CAA section 307(d)(6)(C) which prohibits a promulgated rule from being based on information or data which is not in the docket "as of the date of promulgation" – including relying on future data to set emissions budgets. The commenter states that the EPA incorrectly colors the future re-budgeting as "ministerial" in nature, and agrees that while the approach is formulistic in nature, the appropriateness of the outcome is wrought with so many potential variables that a reasonable person commenting on today's rule could not anticipate the outcome in future years in a manner that allows for thoughtful or complete comment now on the proposed approach. In short, the commenter believes that there is not enough information in the rulemaking record to determine if and how a given unit or state will be disadvantaged by any future budget allocation (*e.g.*, left with too few allowances to operate for purposes of emissions testing or to meet peak demand in a future year), or whether the total budget and allowance system will be set at levels resulting in over-control of emissions in one or more states. The commenter highlights that the EPA attempts to cure this defect by providing a comment period on the EPA's emissions budget decision, but a comment period does not afford a party the same rights of challenge that it would have under CAA section 307(d) to petition for reconsideration and also to petition for judicial review. The commenter further notes that the comment period does not allow the EPA to apply a rule of reason to its future emissions budget allocations, because EPA would have no authority to deviate from the required formula application no matter how unsensible the outcome.

Commenter (0400) proclaims that dynamic state emissions budgets are unauthorized under the provision because the failure to eliminate significant contribution to nonattainment has been mitigated through compliance with state budgets.

Commenter (0519) states that the EPA's approach is inconsistent with its own environmental justice (EJ) screening tools and is unnecessary to protect [EJ] communities. Commenter says first, the EPA cannot utilize EJ concerns to expand its authority under CAA section 110(a)(2)(D)(i)(I). The CAA's good neighbor provision limits the EPA's authority to eliminating emissions significantly contributing to downwind air quality problems. The EPA's daily backstop limit exceeds this authority by subjecting covered units to overcontrol, requiring additional emissions reductions beyond the EPA's chosen level of stringency.

Commenter (0554) maintains that the enhancements proposed in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards add significant and unnecessary legal risk to the Agency as well as impose a cost on the industries it seeks to regulate and are likely to generate substantial uncertainty during legal challenges. The commenter asserts that the proposed enhancements raise new issues and concepts not previously tested/vetted in court, and each time the EPA has adopted a new interstate transport trading program, the D.C. Circuit has accepted some of the changes, while rejecting others. The commenter provides a brief discussion on court findings (Michigan v. EPA, North Carolina v. EPA, EME Homer City v. EPA, etc.) and suggests that the judicial track record provides plenty of direction on how to establish a lawful and effective trading program to address interstate transport. The commenter states that unless the EPA can better justify its conclusion that these enhancements are needed to accomplish the purpose of the program, they ask that the EPA consider adopting a program more clearly within the lines of what the D.C. Circuit has already reviewed and endorsed. More specifically, the commenter requests that the EPA confirm that the proposed enhancements are not intended to accomplish purposes outside of the scope of the EPA's authority under the "good neighbor" provision of the CAA.

Commenter (0550) contends that the EPA's approach to rely on its prior analyses from its earlier "good neighbor" FIPs is not applicable under the proposed rule; therefore, the proposed rule has not been justified and is unlawful. The commenter notes that traditionally, under prior "good neighbor" FIPs, the EPA has relied on the flexibility inherent in a trading program to address real-world variability in operations, electricity demand, and other inaccuracies in its prior actions rather than a "direct control" approach. The commenter claims that the EPA's proposed approach throws aside the Agency's longstanding practice of allowing market-based trading programs to reflect regionally-cost-effective and practical emissions reductions; however, the Agency does not justify this departure from its prior practice, nor does the EPA explain how these significant changes still account for and adapt to real-world variability. Instead, the commenter notes that the EPA cloaks its new approach in the language of its prior rules to avoid the justification and analysis that the EPA's new approach requires. The commenter continues to note that because the EPA's fundamental changes to its approach cannot be reflexively validated by prior court decisions and because EPA has not sufficiently analyzed the implications of or justified the basis for its technology-forcing mandate in the proposed rule here, the rule is unlawful and not supported.

Commenters (0300, 0395) state their belief that changes to the CSAPR program changes are outside of the EPA's authority under the "good neighbor" obligation of the CAA and are arbitrary and capricious. The commenters say that all of the elements that make trading programs beneficial in allowing the market to find the least expensive control options would be defeated by the changes in this proposal to the current CSAPR program. At least one commenter says that while the proposed rule has vanishingly small effects on interstate ozone, it would force premature closure of fossil fuel-fired EGUs and threaten electric grid reliability. The commenters further argue that the EPA has proposed a system that would continuously reduce state NO_X budgets over time, without rulemaking, without any evidence or analysis of linkage to the air quality impacts at downwind monitors, and without any end date.

Commenter (0512) states that trading program enhancements such as dynamic budgeting and the daily backstop emissions rate exceed the EPA's authority under the Act.

Response:

These comments are responded to in Section III.B.1.d of the preamble.

1.5 Authority to Regulate Non-Electric Generating Unit (EGU) Emissions

Comments:

Commenter (0300) underscores the point that emissions of criteria pollutants from all of the stationary sources (non-EGUs) addressed in this action are already regulated under CAA section 111(b). The commenter lists the 5 non-EGUs/industries subject to the proposed rule, along with applicable 40 CFR part 60 subparts – *e.g.*, NO_X standards are addressed in 40 CFR part 60, subparts D, Da, Db, and Dc for Industrial/Commercial/Institutional Steam Generating Units. The commenter points out that standards, under CAA section 111(b), are required to be frequently reviewed/revised; therefore, the use of this provision as a tool to implement transport goals would ensure equity across the United States and allow for a more robust evaluation of the "best system of emissions reduction" through a vetted process.

Commenters (0359, 0382, 0504), at large, believe that the promulgation of regulations under the proposed rule, specifically the unprecedent inclusion of non-EGU sources, is arbitrary, capricious, and not in accordance with current law; concluding that the EPA exceeded its limited authority (granted by Congress) to regulate states' upwind emissions. Commenter (0504) says that if finalized, the proposed rule would institute the most far-reaching, stringent, and simply unworkable NO_X emissions requirements ever imposed on the iron and steel sector. Specifically, the commenter expresses concerns that the EPA's abrupt policy change means that electric arc furnace (EAF) steelmakers in 23 states may be suddenly thrust into an unprecedented and infeasible new regulatory scheme deemed unnecessary and unworkable by at least 19 states.

Commenter (0405) argues that by imposing emissions limits for non-EGUs, the EPA is going beyond its statutory authority to address only the amounts of upstream emissions with adverse downstream effects.

Commenter (0538) believes that the inclusion of non-EGU sources is rooted in a well-established, court-approved methodology, consistent with the text of the "good neighbor" provision and with the EPA's longstanding interpretation of that provision – *e.g.*, (1998) NO_X SIP Call" regulation and the Clean Air Interstate Rule (CAIR). The commenter adds that while the EPA's 2015 CSAPR did not address non-EGUs, the EPA expressly contemplated when issuing it that future good neighbor rulemaking could require non-EGU reductions and found that while reductions at non-EGUs were not achievable below CSAPR's $500 per ton threshold, "potentially substantial" non-EGU reductions would be available in future rulemakings with higher cost thresholds.

While commenter (0538) supports the EPA's inclusion of non-EGU sources in the rule, but states that more explanation for its selection of non-EGU sources is needed. According to the commenter, the proposed rule's extension of good neighbor obligations to non-EGU sources is consistent with statutory text, regulatory precedent, and caselaw. The commenter says that the broad statutory text of the good neighbor provision, the EPA's long history of interpreting the provision to include non-EGUs, and judicial statements on review of good neighbor rules all support the EPA's authority to regulate non-EGU emissions sources.

In a similar comment, commenter (0758) contends that the EPA has statutory authority to consider reductions from non-EGU units that emit less than 100 tons of NO_X per year, as the good neighbor provision extends to "any source or other type of emissions activity" that significantly contributes to downwind nonattainment or interferes with downwind maintenance.

Commenter (0798) states that the EPA's request for comments on whether to only regulate Tier 1 industries and exempt Tier 2 industries misses the statutory mark. The commenter asserts that the EPA only has regulatory authority to prohibit amounts of emissions from a "source or other emissions activity" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State." According to the commenter, it is therefore arbitrary and unlawful for the EPA to consider regulating an industry on some other basis (such as whether the EPA considers an industry to be "Tier 1" or "Tier 2"). Accordingly, the commenter asserts that the EPA should avoid overcontrol and adhere to the statutory text by only regulating industries within a particular state which significantly contribute to that state's linked receptors, rather than by whether the EPA happens to classify the industry as "Tier 1" or "Tier 2" on a nationwide basis.

Commenter (0798) comments that many aspects of the proposed rule exceed the discretion granted to the EPA under the statutory text, and thus will not be protected by Chevron deference, and may serve as a basis for challenges to Chevron itself, or at least to further limits on the EPA's deference under Chevron. Commenter says as discussed in detail throughout these comments, the many ways in which the EPA analyzes and proposes to regulate non-EGUs in ways different than what has been upheld for EGUs in prior good neighbor rulemakings, and the various other unreasonable or arbitrary positions identified throughout these comments are not reasonable interpretations of the statute, and do not merit Chevron deference. Commenter says the EPA's decision to subject sources in upwind states to control limits stricter than the RACT level of control Congress has set for NAAQS compliance in even nonattainment areas is outside the discretion of the EPA, and clearly conflicts with the structure of Title I of the CAA, the good neighbor provision, and the intent of Congress, and does not merit Chevron deference.

Commenter (0798) disagrees with the EPA's assertion based on the D.C. Circuit's opinion in Wisconsin v. EPA, that it is authorized to ignore "claims about infeasibility of controls" raised by any facility. The commenter contends that the EPA mischaracterizes the D.C. Circuit decision. The commenter clarifies that discussion of "feasibility," in this case, was not about technical feasibility of whether controls would be capable of being retrofitted or concerning whether controls could actually feasibly reduce the emissions to the extent needed, but rather, the "feasibility" issues the court and the EPA discussed were centered around whether the EPA had enough time and information to draft and implement required reductions in a timely manner. The commenter also emphasizes that the technical feasibility questions raised by the proposed rule's unit level emissions limits are categorically different than the "feasibility" concerns discussed in Wisconsin, because according to the commenter, the rule at issue in Wisconsin involved only statewide emissions budgets and did not involve any command-and-control limits. The commenter further implies that facilities could meet required reductions of NO_X if a statewide emissions cap was imposed, because that would allow, for instance, a facility the option of operating less to comply with requirements. Instead, the commenter argues that the proposed rule, as written, would make it impossible for a facility to comply if the proposed controls cannot feasibly reduce emissions to the extent the EPA assumes.

Response:

These comments are responded to in Section III.B.1.c of the preamble.

1.6 Major Questions Doctrine

Comments:

Commenters (0306, 0346, 0372, 0394, 0395, 0400, 0409, 0542, 0547, 0798) state their belief that the proposed rule is an attempt to overhaul the energy sector and evokes "major questions." Many of these commenters assert that the EPA has not been granted the authority by Congress under the CAA and/or "good neighbor" to regulate the utility markets, nor has Congress given the EPA instructions on how to use that power. At least one commenter (0395) says that the Supreme Court considered the attempted overhaul of the tobacco industry to be a "major question" [Brown & Williamson, 529 U.S. at 159]. Other commenters briefly describe the factors typically considered by the Supreme Court when determining whether a question is major, and argue, based on these factors, the implementation of the proposed rule is an "economically significant regulatory action" as defined by the Office of Budget and Management (OMB) – *e.g.*, impacts to the economy estimated at $100 million annually. A majority of commenter suggests that the "major questions" doctrine forbids EPA from making decisions of vast economic and political significance in the absence of an express delegation of such authority from Congress. At least one commenter (0409) underscores the point that neither CAA section 110 nor anything else in the CAA provides a statement from Congress that authorizes a shift in power/authority. Most commenters say that the proposed rule, as written, would collectively result in the wholesale reordering of the U.S. power sector and impact the ability of millions of Americans to receive reliable, cost-affordable electricity. A few of the commenters share the belief that "major questions" are poor candidates for agency decision-making because they often involve matters extending beyond a single agency's expertise; requiring Congress to "speak clearly" to grant an agency authority over a major question. In addition, commenters declare that the "major questions" doctrine, as upheld by the Supreme Court, limits the EPA's ability to extend permitting requirements to a vast category of greenhouse gas-emitting sources [573 U.S. at 315].

Commenters (0346, 0395, 0547) state that the EPA violates the Major Questions Doctrine, which "forbids EPA from making decisions of vast economic and political significance in the absence of an express delegation of such authority from Congress." Commenter (0547) writes, courts interpreting the good neighbor provision have confirmed that the EPA's FIP will pass judicial muster only if it (a) respects the state's freedom to select whatever mix of emissions limitations the state deems best suited to its particular situation; (b) avoids impermissible, mandatory source-specific means of implementation; and (c) provides the state real choice with regard to the control measure options available to meet the budget requirements." Commenter argues that the proposed rule violates these principles the EPA goes beyond addressing contribution to NAAQS through emissions controls that a State may select in its discretion. Instead, it forces technology and operational changes that are not economically feasible and, in many cases, not technically feasible. Indeed, the EPA states explicitly that one of the results of the proposed rule is generation shifting away from fossil-fuel fired EGUs towards the agency's preferred lower-emitting energy sources. But Congress did not clearly delegate to the EPA the power through the good neighbor provision to upend traditional State and federal roles in tackling NAAQS compliance, nor did Congress clearly delegate to the EPA the power to restructure the Nation's energy supply away from fossil fuel-fired sources.

Commenter (0372) maintains that the proposed rule effectively requires states to engage in "generation shifting" to achieve EPA-imposed emissions reductions, which will result in the forced retirement of dozens of gigawatts of power generation currently operating in the United States. The commenter states that the loss of these gigawatts would threaten the stability of the power grid and, therefore, the lives and livelihoods of thousands of U.S. citizens, which blatantly violates both the Major Question Doctrine and the Nondelegation Doctrine. The commenter recommends that the EPA withdraw the rule before it is struck down in federal court.

Commenter (0542) states the Major Question Doctrine reflects that the Supreme Court "expect[s] Congress to speak clearly" if it wishes to grant an executive agency authority over decisions "of vast economic and political significance.

Commenter (0357) recommends that, at a minimum, the EPA delay further work on this rule until the Supreme Court decides *West Virginia v. EPA* (Sup. Court 20-1530), argued Feb. 28, 2022, to definitively determine the EPA's authority in this regard.

Commenter (0349) argues that the EPA is incorrect in claiming that generation shift is both technically and legally authorized under the CAA The commenter submits that the EPA's conclusion that generation shifting poses no conflict to FERC or state jurisdictions under the FPA is incorrect, and the legal issues surrounding the concept of generation shifting are thoroughly presented in the ACE litigation pending before the U.S. Supreme Court of Appeals, *West Virginia v. EPA*, Case Nos. 20-1530, 20- 1531, 20-1778 and 20-1780. The commenter notes that the petitioners in that litigation have presented a challenge to generation shifting as a regulatory action, arguing that agency-enforced generation shifting away from coal is a major question that implicates hundreds of billions of dollars, tens of thousands of potentially regulated parties, and years of congressional wrangling. The commenter adds that similar to the dilemma presented in the ACE litigation is the concern that the EPA has improperly invoked CAA section 110, resulting in an imbalance between upwind and downwind states' obligations to develop SIPs for the 2015 ozone NAAQS. The commenter states that the EPA's proposed generation shifting assumptions of the FIP and prior proposed denials of good neighbor SIPs, are rife with unresolved legal issues and technical complexity. The commenter states that the EPA's FIP has the impact of changing power generation to the point of changing the energy economy, and the EPA has failed to recognize the role of the RTOs with respect to grid reliability. Further, the commenter asserts that the EPA fails to recognize that grid reliability obligations have no artificial state borders, and that any generation "shifting" is tantamount to exacerbating current and material grid reliability issues. The commenter claims that in some cases, this proposed rule could force EGUs to either close or transition to seasonal operations based on a legal and technical rationale that is not supported in law.

Commenters (0542, 0798) state that the proposed rule will not withstand review under the major question and nondelegation doctrines. The commenter (0542) says:

> "The Major Question Doctrine reflects that the Supreme Court "expect[s] Congress to speak clearly" if it wishes to grant an executive agency authority over decisions "of vast economic and political significance." Similarly, the Nondelegation Doctrine ensures that critical choices of economic and societal policy are made by Congress and, where Congress does delegate authority to unelected bureaucrats, it must articulate an "intelligible principle" to guide and limit exercise of the authority.
>
> According to the commenter, the proposed rule effectively requires states to engage in "generation shifting" to achieve EPA-imposed emissions reductions, which will result in the forced retirement of dozens of gigawatts of power generation currently operating in the United States. The commenter states that the loss of these gigawatts would threaten the stability of the power grid and, therefore, the lives and livelihoods of thousands of U.S. citizens, which blatantly violates both the Major Question Doctrine and the Nondelegation Doctrine. The commenter recommends that the EPA withdraw the rule before it is struck down in federal court.

Commenter (0798) adds that the proposed rule would mandate generation shifting in the EGU sector by setting limits too low to achieve in the absence of generation shifting and through the creation of the "backstop daily rate for large coal EGUs," which would only apply to coal fired plants. The commenter relates that the Supreme Court has accepted review of a set of cases challenging the ACE and CPP rules, which have a similar reshaping effect on the energy sector by the EPA. The commenter states that the final rule must account for and comply with any interpretation of the major questions doctrine in that case. The commenter also states that the proposed rule's unprecedented use of the good neighbor provision to impose emissions limits on a unit specific basis for entire industries, without any consideration of unit specific feasibility or demonstration that the source itself is contributing to any nonattainment or maintenance site also runs afoul of the major questions doctrine. According to the commenter, the good neighbor provision, which focuses only on limiting amounts of emissions significantly contributing to actual nonattainment of maintenance issues in downwind states, does not clearly authorize the vast industry shaping and reorganizing that the EPA attempts to issue in the proposed rule.

Commenters (0394, 0400) state the emissions budgets are infeasible, will cause generation shifting, and therefore exceeds the EPA's authority and violates the major questions and nondelegation doctrines.

Response:

The EPA disagrees that this action triggers or violates the major question doctrine. The good neighbor provision, CAA section 110(a)(2)(D)(i)(I), clearly authorizes the states (and then the EPA, should it need to exercise FIP authority) to develop SIPs that prohibit emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states. Over the course of several prior rulemakings spanning back to the 1990s, the EPA has developed a consistent framework for defining these "good neighbor" obligations, which it has then applied across six prior NAAQS revisions: the 1979 1-hr ozone NAAQS, the 1997 8-hr ozone NAAQS, the 2008 8-hr ozone NAAQS, the 1997 annual particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$) NAAQS, the 2006 24-hr $PM_{2.5}$ NAAQS, and the 2012 annual $PM_{2.5}$ NAAQS.[7] In Section II.D of the preamble, we provide a more detailed overview of this regulatory history and the associated case law. Most notably for purposes of responding to these comments, the D.C. Circuit first upheld the EPA's analytical approach to addressing interstate ozone transport in *Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000), and the U.S. Supreme Court upheld the same basic framework as it was applied in the 2011 CSAPR. In particular, the Supreme Court upheld the propriety of the EPA's exercise of FIP authority and our use of cost in defining "significance" at Step 3 of the framework to allocate responsibility among upwind states while also identifying statutory constraints that ensure the EPA cannot "over-control" upwind-state emissions. *EME Homer City v. EPA*, 572 U.S. 489 (2014).

The Agency is applying that same basic framework upheld in *Michigan* and *EME Homer City* to define states' good neighbor obligations in this rulemaking, as necessary to eliminate significant contribution and interference with maintenance for the more protective 2015 8-hr ozone NAAQS. The EPA acknowledges that the application of this framework here has produced new regulatory conclusions regarding the emissions that must be eliminated to satisfy the requirements of CAA section 110(a)(2)(D)(i)(I). We also acknowledge that certain aspects of that framework have evolved in response to new information, case law, and policy considerations (as has been the case throughout the history of implementation of the good neighbor provision). However, no aspect of the EPA's interpretation of the statute in this action is novel, unheralded, or inconsistent with prior interpretation, when viewed through the lens of this long and consistent legal and regulatory history.

Thus, the major question doctrine is inapplicable to this action. In *West Virginia* (which was pending during the comment period for this action), the Supreme Court applied the doctrine to

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[7] For the 2012 annual $PM_{2.5}$ NAAQS, due to the limited number of likely projected receptors, EPA issued a guidance memorandum in March 2016 and did not engage in significant rulemaking activity. In that memorandum, EPA provided guidance applying the 4-step interstate transport framework. *See* "Information on the Interstate Transport 'Good Neighbor' Provision for the 2012 Fine Particulate Matter National Ambient Air Quality Standards under Clean Air Act section 110(a)(2)(D)(i)(I)," March 17, 2016, *available at* https://www.epa.gov/sites/default/files/2016-08/documents/good-neighbor-memo_implementation.pdf.

hold that the EPA's effort to regulate greenhouse gases from the power sector through a "generation shifting" approach to the "best system of emissions reduction" under CAA section 111(d) was beyond the authority Congress gave the EPA under that provision. However, the Supreme Court explained that the doctrine does not supplant ordinary principles of statutory interpretation except in "extraordinary" cases—*i.e.*, those where an agency's action is both enormously consequential and rests on a statutory basis that Congress would have been unlikely to have intended. *West Virginia v. EPA*, 142 S. Ct. 2587, 2608 (2022). This is not such an extraordinary case. Indeed, the Supreme Court itself held in *EME Homer City* that the EPA's interpretation of the phrase "significant contribution" was resolvable through application of the analytical framework of *Chevron*. *See* 572 U.S. at 512-515 (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council,* 467 U.S. 837 (1984). The Supreme Court also otherwise affirmed the EPA's exercise of FIP authority in CSAPR.

Additional judicial precedents from the D.C. Circuit since *Michigan* have also continued to affirm the Agency's authority under the good neighbor provision to implement programs that are in material respects like the program finalized here. These decisions demonstrate that the EPA's longstanding framework for implementing good neighbor obligations is not only firmly established as a matter of administrative precedent but has been upheld in relevant respects repeatedly by the courts.

Notably, these commenters do not seek to relitigate the Agency's interpretation of "significant contribution" as allowing for consideration of cost, which would require overturning the Supreme Court's holding in *EME Homer City*. They do not mount any other argument that this action is incompatible with the text, structure, or overall statutory context or purpose of the CAA. Nor do they argue this action is inconsistent with any other judicial holding relevant to the implementation of the good neighbor provision. Rather, the commenters assert that the sheer magnitude of impact of this action in terms of cost or its effect on the power sector is sufficient to trigger the major questions doctrine. But the impact of an action alone has never been found sufficient to conclude that an administrative agency lacks statutory authority for its action. Rather, the concern of the courts is in whether Congress intended for the agency to exercise such power. *See West Virginia*, 142 S. Ct. at 2609 (the doctrine is intended to address "a particular and recurring problem: agencies asserting highly consequential power *beyond what Congress could reasonably be understood to have granted*") (emphasis added).

Nothing in this rule or in the EPA's longstanding approach to defining "good neighbor" obligations stretches the statute beyond what Congress intended. This is evinced in the history of the modern good neighbor provision. Congress strengthened the provision in the 1990 CAA Amendments after prior versions of the provision proved ineffective at addressing interstate pollution, particularly for regional pollutants like ozone.[8] Following that amendment, the EPA

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[8] For a general review of the history of efforts under the Clean Air Act to address interstate pollution leading up to the current good neighbor provision and related amendments in the 1990 Clean air Act Amendments, see Geoffrey L. Wilcox, *New England and the Challenge of Interstate Ozone Pollution Under the Clean Air Act of 1990*, 24 Boston Col. Envt'l Affairs L. Rev. 1, 13-34 (1996).

promulgated a series of rules to implement the revamped provision to eliminate "significant contribution." All of these rules required what might be considered "consequential" actions from regulated sources, and in particular the electric power sector. Those rules imposed substantial costs. For example, the EPA estimated that the NO_X SIP Call would cost $1.7 billion (in 1990 dollars) annually to implement. 63 FR at 57478. CAIR was estimated to cost the power sector $2.4 billion in 2010 and $3.4 billion in 2015 (in 1999 dollars). 70 FR at 25305. CSAPR was estimated to cost the power sector $810 million in 2014 (in 2007 dollars). 76 FR at 48215. (All of these rules also delivered substantial monetized and non-monetized public health and environmental benefits and were therefore found to be net beneficial in the accompanying regulatory impact analyses (RIA).) And yet, despite what might be considered substantial consequences of the EPA's previous major good neighbor actions, since 1990, Congress has never amended CAA section 110(a)(2)(D)(i)(I). Commenters supply no explanation why the application of that same framework here—producing costs and benefits of similar magnitude to prior good neighbor actions—should suddenly be found to be beyond what Congress could have intended.[9]

The EPA further disagrees with commenters' assertions regarding the Agency's authority to regulate the power sector. These comments are addressed in more detail in Section 1.3 (Authority to Regulate Power Sector Emissions). However, in brief, we note that this rule is not intended nor is expected to have a transformative effect on the power sector. The control stringency for EGUs has been determined through evaluating conventional, at-the-source pollution control technologies that have already been implemented by many other EGUs. Further, the rule is designed to accommodate transition from coal-fired EGUs as may occur in response to other mandates, incentives, or economic factors, see Section VI.B of the preamble. Unlike prior transport rules, the EPA has not included even a small amount of "generation shifting" in the budget setting process. See Section V.B.1.f of the preamble to this rule In addition, the EPA has taken a number of steps to ensure that the rule will not introduce "grid reliability" concerns. See Section VI.B.1.d of the preamble. In short, there is simply no basis for commenters' assertions that the Agency is intruding upon the regulatory domain of state utility regulators or other federal agencies or that the rule is otherwise "transformative" in some way not intended by Congress.

Finally, the EPA disagrees with commenters' assertions that the control requirements in this final rule are infeasible or impossible for sources to implement. However, these are record-based determinations, and commenters' more detailed assertions in this regard, and how the EPA has responded and/or adjusted the final rule from proposal to address any legitimate concerns regarding feasibility, are addressed elsewhere in the record.

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[9] As discussed in Section VIII of the preamble and in the RIA, the highest estimated total annual cost of this action peaks around $1.3 billion (in 2032, using 2016 dollars and a 3.76% real discount rate), and in many years the estimated total annual compliance cost is considerably less than that. See Table VIII-8 in the preamble and Table ES-15 in the RIA. Thus, the economic impact in terms of total cost of compliance is actually comparable or less than the NO_X SIP Call, CAIR, or CSAPR.

1.7 Nondelegation Doctrine

Comments:

Commenters (0346, 0372, 0400, 0409, 0542) assert that the proposed rule, as written, threatens to undermine Congressionally-granted authority and violates the nondelegation doctrine – *i.e.*, the proposed rule wrongly suggests that the EPA was delegated authority by Congress to regulate energy utility markets/re-shape the electricity sector. Commenters (0346, 0372, 0409) add that the nondelegation doctrine prohibits Congress from delegating its powers to administrative agencies without providing the Agency with an "intelligible principle" to guide and limit exercise of the authority [*J. W. Hampton & Co. v. United States*, 276 U.S. 394, 409 (1928)]; thus, the doctrine ensures critical choices, including economic and societal policy are made by Congressional representatives. Commenter (0346) underscores the point that "Congress has not provided EPA the authority to regulate the utility markets, much less provided EPA with instructions regarding how to use that power." Furthermore, the commenter maintains that this rule will have significant impacts to the power sector, but Congress has not provided a specific guidance, standard, or "guardrail" to the EPA on this topic.

Commenter (0372) suggests that the lack of delegation is further supported by the absence of any guidance or standard from Congress to the EPA. The commenter says that when delegating authority to an agency, Congress must provide some guidance, standard, or guardrail within which the agency may act; adding that the Constitution bars Congress from giving "literally no guidance" or overly vague standards when conferring agency power [*Whitman v. American Trucking Associations*, 531 U.S. 457, 474 (2001)].

Commenter (0400) state the emissions budgets are infeasible, will cause generation shifting, and therefore exceeds the EPA's authority and violates the major questions and nondelegation doctrines.

Response:

The EPA disagrees that the good neighbor provision, CAA section 110(a)(2)(D)(i)(I), constitutes an unconstitutional delegation of legislative power. The Supreme Court has recently confirmed the "intelligible principle" standard for nondelegation challenges. *Gundy v. United States*, 139 S. Ct. 2116 (2019). "The constitutional question is whether Congress has supplied an intelligible principle to guide the delegee's use of discretion. So, the answer requires construing the challenged statute to figure out what task it delegates and what instructions it provides." *Id.* at 2123. The Supreme Court has "over and over upheld even very broad delegations" under that standard. *Id.* at 2129. Only twice ever has the Supreme Court found a delegation to be unconstitutional. *Id.* One "provided literally no guidance for the exercise of discretion," and the other "conferred authority to regulate the entire economy on the basis of no more precise a standard than stimulating the economy by assuring 'fair competition.'" *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 474 (2001) (discussing *Panama Ref. Co. v. Ryan*, 293 U.S. 388 (1935), and *A.L.A. Schechter Poultry Corp. v. United States*, 295 U.S. 495 (1935)).

In the more than eighty-seven years since those two decisions, the Supreme Court has consistently upheld "Congress' ability to delegate power under broad standards," *Mistretta v. United States*, 488 U.S. 361, 373 (1989), and "ha[s] 'almost never felt qualified to second-guess Congress regarding the permissible degree of policy judgment that can be left to those executing or applying the law,'" *Am. Trucking*, 531 U.S. at 474–75 (quoting *Mistretta*, 488 U.S. at 416 (Scalia, J., dissenting)).

With respect to the good neighbor provision, the D.C. Circuit analyzed this question in *Michigan v. EPA*, in reviewing the NO_X SIP Call, and concluded that there is no nondelegation problem. *See* 213 F.3d 663, 680-81 (D.C. Cir. 2000). Notably, this decision came after the D.C. Circuit had applied the nondelegation doctrine in striking down the EPA's promulgation of the 1997 ozone NAAQS revision under CAA section 109(b)(1), *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027 (D.C. Cir. 1999), but *before* the U.S. Supreme Court reversed that decision as an over-extension of the doctrine, 531 U.S. 457, 472-76 (2001). The Court in *Whitman* found a requisite "intelligible principle" in CAA section 109(b)(1), which the Court interpreted "as requiring the EPA to set air quality standards at the level that is "requisite" that is, not lower or higher than is necessary—to protect the public health with an adequate margin of safety"; this the Court found "fits comfortably within the scope of discretion permitted by our precedent." 531 U.S. at 475-76.

Here, the good neighbor provision remains unchanged from the statutory text the EPA first applied in the NO_X SIP Call, and both the D.C. Circuit and the Supreme Court have had occasion since *Michigan* to further interpret the meaning of this text and review the EPA's application of it across several rulemakings. In each of these rulemakings, the EPA has applied a consistent analytical approach to addressing the problem of interstate pollution, and that approach faithfully adheres to the terms of the statute as Congress enacted it. Each step of this process is tied to "intelligible" terms in the statute: the identification of "nonattainment" and "maintenance" receptors for a particular NAAQS (Step 1); the identification of "contribution" to those receptors by analyzing emissions from "any source or other type of emissions activity" within each state (Step 2); the analysis of what "amount" of that contribution is "significant" (or "interferes" with maintenance) (Step 3); and finally, the promulgation of "adequate provisions prohibiting" those emissions (Step 4).

This framework for implementing the good neighbor provision was upheld by the Supreme Court in *EME Homer City* as a reasonable interpretation of the Act, 572 U.S. at 513-14. The Court recognized in reaching this conclusion that the problem of interstate air pollution introduced a "thorny causation problem" and "[t]he realities of interstate air pollution . . . are not so simple." *Id.* at 516. *See Am. Trucking*, 531 U.S. at 475 ("[T]he degree of agency discretion that is acceptable varies according to the scope of the power congressionally conferred."). The Court found the Agency's solution to that "thorny" problem in the 4-step interstate transport framework to be statutorily authorized and "equitable" and "efficient." *Id.* at 519. Nonetheless, the Court also found clear limitations in the statute on the scope of the EPA's authority. The Court noted, for instance,

> Just as EPA is constrained, under the first part of the Good Neighbor Provision, to eliminate only those amounts that "contribute ... to *nonattainment,*" EPA is limited, by the second part of the provision, to reduce only by "amounts" that "interfere with

> *maintenance*," *i.e.*, by just enough to permit an already-attaining State to maintain satisfactory air quality.

Id. at 517 n.18 (emphasis in original). The Court held that the EPA may not "over-control" emissions: "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. On remand from the Supreme Court, and applying this principle, the D.C. Circuit found instances of over-control in the original CSAPR record and remanded to the Agency to resolve those instances where the court found the Agency may have overstepped its authority. *See* 795 F.3d 118.

The D.C. Circuit has identified other statutory bounds on the scope of the EPA's discretion. For instance, the statute provides that the EPA must implement the good neighbor provision "consistent with the provisions of [title I of the CAA.]" CAA section 110(a)(2)(D)(i). In *Wisconsin v. EPA*, 938 F.3d at 313-18, the court found (as it had previously in *North Carolina*) that this required the EPA to align implementation of good neighbor obligations with the downwind attainment schedule. And the D.C. Circuit has held that the EPA may not implement an emissions reduction program under the good neighbor provision that fails to ensure that each state has eliminated its own significant contribution. *North Carolina*, 531 F.3d at 921.

Finally, we note that the EPA's rulemaking authority in the promulgation of any FIP is subject to additional provisions in the CAA that limit when and how the EPA may directly implement good neighbor obligations. *See* CAA section 110(a)(1) (good neighbor obligations triggered only upon promulgation or revision of a NAAQS); *id.* 110(c)(1) (establishing when the EPA may promulgate FIPs); *id.* 302(y) (defining the term "FIP," and listing acceptable methods of reducing emissions); and *id.* 307(d) (providing rulemaking procedural requirements and provisions for judicial review of certain CAA actions including the promulgation of FIPs).

The EPA therefore disagrees that the good neighbor provision, particularly when viewed in the entire statutory context and in light of a quarter-century of regulatory implementation and interpretive case law, constitutes an unconstitutional delegation of legislative authority.

1.8 Tribal Authority

Comments:

Commenters (0259, 0402) disagree with the EPA's approach to combine the allowances for new units that previously were divided into two new-unit set-asides: one for new units under state authority and one for new units in Indian Country (87 Fed. Reg. at 20126), and expressed concerns that the proposed rule, as written, blur the lines of authority between states and Tribal. The commenters are particularly concerned with the how Tribal decisions would be impacted if, for example, a state does not replace the EPA's default allocations with state-determined allocations but goes ahead with permitting new units that use up the set aside. The commenters stress the point that federally recognized Indian Tribes are sovereign nations with inherent rights and these rights are both, separate from state rights, and ensured by the U.S.

Constitution, treaties, and legal precedent. The commenters further add that tribal sovereign should not be infringed upon by the federal government, much less by an agency regulation, and asked that the Agency ensure that proposed rule does not constrain Tribal decisions to state decisions.

Response:

The EPA disagrees that this rule "blurs the lines" between state and tribal authority. This rule promulgates a set of FIPs by which the EPA will directly implement the relevant requirements across areas of state implementation planning authority and areas subject to tribal jurisdiction, under authority of CAA section 110(c)(1) and section 301(d), respectively. The commenters refer to an adjustment in the method of setting aside allowances for new units and reallocating those allowances to existing units if they are not distributed to new units. This change in methodology does not alter the prior trading program regulations in a way that would allow states to control new unit allowance set-asides, and it does not impinge on the ability of new units locating in Indian country subject to tribal jurisdiction to obtain allowances to the same extent as had been provided for in prior trading programs under 40 CFR part 97. In this respect, the rule continues to respect tribal sovereignty and maintains the existing distinction between those allowances for which states may take over the allocation methodology, and those allowances that remain under federal control as necessary to maintain the EPA's direct implementation role in areas of Indian country subject to tribal jurisdiction. Further, tribal authorities in such areas have the ability to take over the implementation of allowance allocations in areas subject to their jurisdiction, should they choose to do so, to the same degree that states may (*i.e.*, subject to the EPA retaining the management of allowances in the new unit set aside).

Even though the EPA retains management of new-unit set-asides under scenarios in which states or tribes wish to continue participating in the trading program but wish to adopt their own method of allocating allowances to existing units,[10] this does not infringe tribal sovereignty. Neither tribes nor states possess any inherent right or ownership interest in these allowances to begin with. *See* 40 CFR 97.1006(c)(6)(ii) ("Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization [to emit as provided by a CSAPR NO_X Ozone Season Group 3 allowance] to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act."); *see also id.* 97.1006(c)(7) ("*Property right.* A CSAPR NO_X Ozone Season Group 3 allowance does not constitute a property right.").

The new-unit allocation methodology and its rationale are further discussed in Section VI.B.9 of the preamble.

[10] As discussed in Section VI.D of the preamble, states and tribes retain the authority to develop implementation plans to replace the FIP that do not rely on the trading program at all, should they choose to do so.

1.9 Overcontrol Claims

Comments:

Commenters (0306, 0317, 0357, 0326, 0350, 0354, 0382, 0396, 0398, 0513, 0531, 0541, 0551, 0554) state the Supreme Court has clearly affirmed that such "overcontrol," reducing state level emissions beyond that which is necessary to achieve attainment in downwind states, is prohibited. The EPA v. EME Homer City Generation, L.P., 572 US 489, 492 (2019). Many of the commenters point out that in promulgating a good neighbor FIP, the EPA is required to quantify the emissions from a state that impact the downwind states. Once those emissions reductions required by a budget are achieved, the state has met its obligations. The commenters maintain that the EPA's proposal to continue to ratchet down emissions beyond what is required for states to meet their attainment obligations amounts to an unlawful overcontrol. Indeed, this proposal goes well beyond a "trading program" as typically understood, and rather is a regulatory program that sets emissions limitations and mandates specific required emissions control equipment for EGUs. Regulating existing EGUs in such a manner is beyond the good neighbor provisions in CAA section 110 and, thus, beyond the EPA's authority.

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0372, 0382, 0798) state the EPA proposing RACT with SCR/selective non-catalytic reduction (SNCR) technology will force industry closures, which is over-control.

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0798) argue that the proposed rule is not written to achieve NAAQS compliance or drive greater controls/use of existing controls. The proposal pushes any source beyond any achievable reductions and leaves operators with only one choice: alternative generation. Not only is this beyond the scope of the statute and the EPA's authority, as a practical matter, may not be possible to expand or construct the resources that could fill the void when thermal generation is unavailable. As the nation suffers multiple blackouts this month, contributed in part to the lack of adequate, available generation, this rule, if finalized as proposed would only exacerbate the power generation challenges being experienced at this time. This proposal is not merely illegal. It is simply bad judgement.

Commenters (0221, 0314, 0338, 0359, 0501, 0518, 0764) say that the proposed rule could lead to the over-controls of sources in upwind states (*e.g.,* because the 1 percent NAAQS screening threshold is not supported), with some commenters (0314, 0338, 0554) further arguing that current standards are being met (*e.g.,* for Wyoming, the last affected downwind receptor in Colorado is estimated to achieve attainment and maintenance of the ozone standard after full application of emissions reductions from the EGU sector) and additional reductions are unnecessary. Commenter (0554) says that the proposed rule "goes too far." In a similar comment, commenter (0367) states that just as the EPA has an obligation to avoid overcontrol of sources in upwind states, the EPA also has an obligation to avoid under-control of sources in those states.

Commenters (0280, 0284), in general, object to the inclusion of non-EGUs sources, claiming that the proposed rule over-controls sources beyond what is required under law and contradicts the EPA's determinations under NSR. Commenter (0280) adds that the EPA fails to properly identify whether EAFs contribute significantly to a downwind monitor and clearly did not evaluate whether cost-effective control measures are available. The EPA's statutory authority is not only bound by the 4-step interstate transport framework, but the EPA must abide by the Supreme Court's direction to be prudent in determining a state's contributions to downwind states and to avoid requiring "unnecessary" reductions. In a similar comment, commenter (0518) stated that the EPA's proposed controls on non-EGUs at Step 4 fail to follow a reasonable framework for addressing transport and warns against overcontrol. [Note: Commenter provides additional comments on this issue under Section 2.1 (4-Step Approach)] In a similar comment, commenter (0524) states that the proposed rule will result in overcontrol of EGUs.

Commenter (0505) contends that the EPA did not identify significant contributions before determining if emissions reductions are needed, it failed to provide a rational justification for why areas are significantly linked to downwind receptors; nor has the EPA provided a rational justification for why the required reductions are not overcontrol [see EME Homer City, 572 US 489, 523-524 (2014)]; further adding that a state may bring a particularized as-applied challenge if it believes the EPA is requiring reductions "beyond the point necessary to bring all downwind States into attainment."

Commenters (0513, 0519, 0541) imply that the EPA's failure to adequately analyze the combined emissions reductions impacts from EGUs and non-EGUs exceeds its statutory authority under CAA § 110(a)(2)(D) to prohibit "emissions activity within the state" in "amounts which will contribute significantly," and creates an unreasonable risk that individual covered states will be subject to overcontrol. While the EPA has been afforded significant leeway based on the EPA's "statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind," the risks of overcontrol are exponentially increased by conducting separate assessments of significant contributions for EGUs and non-EGUs. The commenters believe the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards goes well beyond "some amount of overcontrol" that may be considered inevitable from the application of the EPA's cost threshold approach to only the EGU sector. The overcontrol created from the EPA's approach is compounded by creating two distinct but parallel programs for EGUs and non-EGUs, each of which will likely include an amount of overcontrol. It is unreasonable for the EPA to fail to consider whether the cumulative emissions reductions exceed what is authorized by CAA section 110(a)(2)(D). The commenters stress as the D.C. Circuit emphasized, "[t]he Supreme Court made crystal clear in EME Homer that over-attainment in downwind locations is impermissible when that excess attainment is 'unnecessary.'"

Commenter (0523) suggests that the inclusion of non-recovery/heat recovery coke plants would result in a proposed rule, if finalized, that is arbitrary and capricious and exceeds the EPA's statutory authority. The commenter believes if the proposed rule were to regulate SunCoke as a mere afterthought, it would necessarily result in over-control. The EPA is required to strike a careful balance to ensure that it eliminates significant contribution to nonattainment while avoiding over-control. The rule asserts that "EPA's over-control analysis . . . shows that the proposed control stringencies for EGU and non-EGU sources do not overcontrol 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[.]" 87 FR. at 20043-44. If the Agency neglects to study the proposed emissions reductions from a particular industry, but then anyway regulates that industry—or even one facility within that industry—it would upset this careful balance and result in more emissions reductions than calculated. As a result, the FIP would exceed the EPA's authority in every state where such facilities are located for overcontrolling emissions from those states. See *North Carolina v. E.P.A.*, 531 F.3d 896, 929–30 (D.C. Cir. 2008) ("EPA's approach—regionwide caps with no state-specific quantitative contribution determinations or emissions requirements—is fundamentally flawed... The trading program is unlawful, because it does not connect states' emissions reductions to any measure of their own significant contributions.").

Furthermore, the commenter (0523) feels that this is precisely what would happen if the proposed rule were finalized to regulate non-recovery/heat-recovery coke plants, or if the EPA failed to clarify that nonrecovery/heat-recovery coke ovens are excluded. There is no evidence in the proposed rule's underlying spreadsheets, the Regulatory Impact Analysis, or the screening assessment that the EPA accounted for current emissions estimates, proposed emissions reductions, or cost estimates for additional NO_X controls at non-recovery/heat-recovery coke oven batteries. If the EPA were to regulate additional sources such as non-recovery/heat recovery coke ovens after the fact, it would upset the careful balance EPA must strike between addressing significant contribution from upwind states without over-controlling those emissions. It would also be arbitrary and capricious because the rule would "rel[y] on factors which Congress has not intended it to consider," namely unnecessary over-attainment in downwind states. See *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Commenter (0523) again respectfully urges the EPA to clarify in the final rule's regulatory text that non-recovery/heat recovery coke plants are not subject to this program.

Commenter (0550) contends that mandating the operation of controls in a certain manner regardless of a state's contribution constitutes unlawful overcontrol and should not be finalized. The commenter provides that, in an effort to support its approach, the EPA claims that "th[e] retention of a constant degree of stringency over time in emissions budgets under a flexible trading program would not constitute over- control any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute over-control." But, according to the commenter (and commenter 0541), the EPA misses the mark—the permanent imposition of emissions rate standards on individual sources would constitute overcontrol at the point that those reductions are no longer needed to ensure downwind attainment. And, regardless, the EPA has not assessed whether permanent, source-by-source emissions rate limits will eliminate "significant contribution" but no more. Under either approach, if a state has eliminated its "significant contribution," no further reduction or obligation is permissible.

Commenter (0668) considers the proposed rule unlawful "overcontrol."

According to commenter (0394), [EPA] failed to conduct an adequate evaluation of overcontrol, as instructed by the Supreme Court – noting that the Courts have found "the Transport Rule violates the statute when it 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" [*EME Homer City*, 572 U.S. at 521]. The commenter asserts that whenever the EPA changes the "amount" of emissions reductions required of a state, it must also check for overcontrol and conducting a single overcontrol analysis when a rule is promulgated, as the

EPA did in past CSAPR rulemakings that imposed static state emissions budgets, is not sufficient to prevent overcontrol under circumstances where state emissions budgets are subject to change from year to year, and daily NO_X emissions rate limits and unit-level secondary emissions limits are in effect indefinitely.

Response:

Comments regarding overcontrol are generally addressed in Section V.D.4 of the preamble. We provide further response here to several additional comments relating to the overcontrol analysis or asserting that this action constitutes overcontrol. Claims that the control strategies determined by the EPA at Step 3 (or as implemented through the emissions control programs established at Step 4) are too stringent or will force some sources to retire do not make out a basis for finding overcontrol as that term has been understood by the courts or applied by the EPA. Similarly, claims that our control determinations are not in keeping with prior emissions control determinations under the RACT program or NSR do not in themselves make out a case for overcontrol. Nonetheless, as explained elsewhere in the record, the emissions control strategies finalized in this rule are based on available NO_X emissions control strategies that are already in use at similar facilities and reflect a level of stringency that is generally commensurate with what many downwind jurisdictions subject to ozone nonattainment planning requirements have already implemented. This rule is not intended to force the closure of any facility but rather to ensure that the covered sources in linked upwind states achieve a minimum level of emissions-control performance to eliminate significant contribution and thereby improve air quality at the identified downwind receptors.

As such, the EPA further disagrees with commenters who assert that the rule imposes massive compliance costs for no benefit. On the contrary, our analysis at Step 3 regarding the effects of the identified emissions control strategies across the linked upwind states is that there will be meaningful air quality improvement at all of the downwind receptors identified at Step 1. See Section V.D of the preamble and the Ozone Transport Policy Analysis Final Rule TSD.

The EPA's response to comments that the "enhancements" to the emissions trading program for EGUs result in overcontrol is in Section V.D.4 of the preamble. The EPA's authority to impose unit-specific emissions limits under the exercise of its FIP authority is explained in Section III.B.1 of the preamble.

The EPA disagrees that the Step 2 contribution threshold of 1 percent of the NAAQS is in itself a ground for a finding of overcontrol. That threshold has been used in numerous prior ozone transport actions and is justified in light of the "collective contribution" nature of the regional ozone problem as further discussed in Section IV.F of the preamble to this rule. The Court in *EME Homer City* recognized that it would be overcontrol for the Agency to require emissions reductions from an upwind state inconsistent with the 1 percent threshold, not that the threshold itself was overcontrol. *See* 572 U.S. at 521 ("EPA cannot require a State to reduce its output of pollution . . . at odds with the one-percent threshold the Agency has set.").

The EPA has considered the cumulative effect of both EGU and non-EGU emissions reductions, as discussed in Section V.D.3 of the preamble, and did so at proposal as well, and so commenters' contentions that we have not are incorrect. The fact that the EPA has found a need for emissions reductions from both EGU and certain non-EGU industrial sources, and has consequently implemented emissions controls through "parallel programs," in commenter's phrasing, does not in itself create conditions for overcontrol nor have commenters offered evidence in support of their statement in this regard.

Commenter's contention that any source is being regulated in this action only as an "afterthought" is incorrect. Each source subject to the EPA's Step 3 and Step 4 determinations has emissions that the EPA finds contribute significantly to nonattainment and/or interfere with maintenance of the 2015 ozone NAAQS in other states. These determinations are distinct from the application of the 1 percent threshold at Step 2, which applies to all of the anthropogenic emissions of each entire state. Such a threshold is not applied on a source- or industry-specific basis. Once the EPA reaches Step 3 in our analysis in this action, as was the case in all of our prior ozone transport rules, the EPA continues to find significant contribution from EGUs, for which the EPA continues to find additional, cost-effective NO_X reductions that will improve air quality at downwind receptors. And the EPA has similarly determined through its assessment of non-EGU sources that certain units in identified, impactful industries significantly contribute to downwind receptors. The EPA finds that, as with EGUs, ozone levels are measurably improved at the identified receptors through the non-EGU emissions control strategies determined in this final action. See Section V.D.2 of the preamble. In any case, with respect to commenter's specific concern regarding proposed regulation of non-recovery/heat recovery coke plants, we are not finalizing emissions control requirements for these types of facilities.

Commenter's contention that this action runs afoul of *North Carolina*'s holding that the EPA must hold each state to prohibiting their own significant contribution takes this holding out of context. The court in *North Carolina* found that CAIR's use of a regional trading program with no state-specific quantification of an enforceable obligation and the rule's method of allocation of responsibility for upwind emissions reductions through that trading program, were not adequately tethered to a determination of the amount of each state's emissions that significantly contribute. *See* 531 F.3d at 920-22. This action is fully compliant with those holdings. The EPA has allocated responsibility at Step 3 through the application of uniform emissions control thresholds in essentially the same manner as it applied in CSAPR, to ensure that those states and sources that have done relatively less to reduce their emissions are brought up to a standard of emissions control of those states that have done relatively more. In the EPA's view, this approach to allocating responsibility is not overcontrol but continues to be an efficient and equitable method of allocating responsibility in resolving the "thorny" causation problem of regional-scale interstate pollution. *See EME Homer City*, 572 U.S. at 519. Further, in this action, each covered source is held to the elimination of its significant contribution through source-specific emissions limits (for non-EGUs) and various trading program features and enhancements (for EGUs), and so this rule does not present the circumstance at issue in *North Carolina*.

1.9.1 Overcontrol Claims Specific to Proposed Trading Program Enhancements

Comments:

Commenters (0317, 0357, 0361, 0366, 0551), in general, argue that the EPA's proposal to "continuously adjust" budgets is overcontrol. Commenters (0317, 0357, 0361, 0366) note the EPA's proposal introduces the new concept of "dynamic" budgets for EGUs, where state budgets would be adjusted for each control period beginning with the 2025 ozone season by applying the control stringency selected by the EPA to updated heat input data measured in the two years prior to the control period. The EPA's proposal to "continuously adjust" budgets in this manner also exceeds its statutory authority. If the EPA had the authority to continually change state emissions budgets in such fashion (which they do not), it would have to make each change pursuant to a notice-and-comment rulemaking structure of section 307(D)(1)(B) of the Act. Instead, the EPA proposes within the rule to adjust state emissions budgets each year by administratively issuing a NODA availability, announcing the state budget for the following ozone season. Thus, as proposed, the rule violates the rulemaking requirements of the CAA.

Commenter (0361) is concerned that if the EPA is permitted to exert the authority to unilaterally recalculate state budgets, the proposed rule does not discuss a mechanism to adjust its overcontrol analysis as state budgets decrease. Failure to consider such adjustments is inconsistent with the clear obligation to ensure that the rule's requirements do not exceed the amount necessary to achieve attainment in the relevant states. An initial overcontrol analysis is not sufficient in the context of a proposed scheme by which the relevant state budget is continually recalculated over time.

Commenters (0361, 0366) argue the cost effectiveness of the program is fundamentally inconsistent with a dynamic budgeting process that is calculated each year through agency action. As interpreted by the Supreme Court, the existing scheme only obligates the elimination of emissions that meet both of the criteria discussed in that opinion. States are not, however, obligated to eliminate emissions that do not fit both criteria. Because of this, any recalculation of the state budget that does not fully account for the satisfaction of these requirements exceeds the scope of the EPA's authority to satisfy the state's good neighbor obligation. The EPA describes a method of recalculating state budgets through "ministerial action." This unilateral administrative action would, however, be inconsistent with the requirement to engage in notice-and-comment rulemaking under CAA section 307(d). Each budget recalculation would functionally be a new cap and trade scheme. The EPA should engage in the ordinary rulemaking process as it fundamentally changes the market for allowances. Untethered from these processes, stakeholders would have little recourse to address errors—like those material errors in the assumptions and modeling previously discussed herein.

Commenters (0394, 0400) argue that the EPA has no authority to modify state emissions budgets without first conducting a notice-and-comment rulemaking, as required under CAA section 307(d) – CAA § 307(d)(1)(B) (subsection 307(d) "applies to . . . the promulgation or alteration of an implementation plan by the Administrator under section 7410(c) of this title"). The commenters state that the proposed rule notes that emissions budgets would be revised via "ministerial action," and say that changes to state budgets have been historically regulated through CAA section 110(a)(2)(A). Thus, the commenters conclude that if the Agency had authority to change the stringency of state budgets, it could only do so following a CAA section 307(d) FIP rulemaking.

Commenter (0424) states dynamic state emissions budgets for EGUs exceeds the EPA's authority under the good neighbor provision and, even if the EPA had authority to change state budgets from year to year, it could not do so without notice-and-comment rulemaking. Commenter (0424) clarifies that if the EPA had substantive authority to change the stringency of state budgets, they could only do so following a CAA section 307(d) FIP rulemaking. Meaning, the EPA could not do so without affording notice to the public and an opportunity for comment.

At large, commenters (0326, 0330, 0354, 0395, 0512, 0519, 0524, 0531, 0533, 0541, 0551, 0554, 0758) state their belief that the proposed changes to the trading program (*i.e.*, dynamic budgeting, the daily backstop rate, annual banking recalibration, and electricity generation shifting) individually and/or collectively would result in illegal overcontrol; adding (commenter 0354) since the NO_X emissions trading program already includes a compliance assurance mechanism set at a level to ensure that the needed NO_X emissions reductions are provided. [Note: Additional remarks pertaining to enhancements, like dynamic budgeting discussed elsewhere in this document].

Commenters (0395, 0519, 0533, 0541) believe, in general, that the proposed "enhancements" to the existing CSAPR program are unrelated to ozone reductions and are simply attempts to make the program itself more stringent and less flexible, equating to a command-and-control rule. Commenter (0395) states that under the EPA's established framework, the EPA must perform multiple checks to ensure it has not overstepped its authority, including confirmation that upwind emissions contribute 1 percent or more of the NAAQS, confirmation that the identified reductions are cost-effective, and confirmation that the reductions are not more than necessary for the downwind state to come into attainment. The commenter writes that the EPA has not performed these checks on its authority with respect to its proposed "enhancements," and therefore, the new elements result in unlawful overcontrol.

Commenter (0519) states that the proposed rule will "attribute fewer emissions reductions to all banked allowances and prevent units from obtaining credit for their reductions, while also limiting the total number of allowances available to facilitate compliance, undermining the intended flexibility-enhancing nature of these measures." The commenter believes that "Absent the flexibility provided by trading, EGUs will be forced to choose between accelerating retirements or, if retirement is not possible for reliability reasons, prolonging the life of fossil units through the installation of costly controls." The commenter disagrees with the EPA's justification of the new constraints, arguing that "The Clean Air Act vests EPA with authorities for the express purposes of remedying implementation plans that are inadequate to mitigate significant interstate pollutant transport. Rather than depriving EGU s in 26 states of necessary and environmentally beneficial compliance flexibility in the anticipation of later problems, EPA should exercise its authorities under the Act and undertake a state-specific rulemaking if and when a problem actually occurs. Simply put, CAA section 110(a)(d)(D) does not require EPA to promulgate or maintain identical FIPs, and EPA should not impute the problems that arise in one state to others in an effort to do so."

Commenters (0519, 0541, 0551) states that the daily backstop limit is not justified to address significant contribution and will result in overcontrol. Commenter (0541) observes that under the EPA’s proposal, even if a state has achieved reductions in the amounts identified by the EPA as the state’s significant contribution, a source would still be penalized if it operated over the backstop emissions rate, and in such a scenario, the EPA’s backstop emissions rate is divorced from any air quality obligation under CAA section 110(a)(2)(D). Commenter (0541) asserts that while the EPA finds the backstop rate is necessary to ensure sources continuously operate installed SCRs, this justification is insufficient, as it is not the stand-alone operation of controls, but the “amount” of NO_X emissions eliminated, that is relevant. In any event, the simple inclusion of a backstop rate fails to account for the nature of SCR operation – *e.g.,* unable to operate under startup, shutdown, and malfunction (SSM) events. The commenter further asserts that if a backstop is finalized, it should not be applied to units that have not installed SCRs, regardless of how the EPA modeled that source during budget setting, and a mass-based alternative may be more appropriate. Commenter (0551) suggests that policy goals (*e.g.,* to prevent individual sources from idling controls), however meritorious in their own right, do not actually address the issue of significant contribution. Even if they did, the commenter says that the limited record information is not sufficient to establish that the backstop emissions limit would have any effect on peak days or overburdened communities. Commenter (0551) states the EPA might be able to revise the daily backstop emissions limit requirement to address the over-control problem the proposed rule poses by sunsetting daily limits for units in states that reduce overall emissions to resolve their significant contributions.

Commenter (0519) mentions that banked allowances represent emissions reductions by a unit in excess of the required threshold. As state budgets continue to lower under the EPA' s dynamic budgeting approach, bank sizes will also be artificially reduced, attributing fewer emissions reductions to all banked allowances and preventing units from obtaining credit for their reductions. The commenter adds that this approach allows the EPA to ignore emissions reductions under the Federal “Good Neighbor Plan” for the 2015 Ozone National Ambient Air Quality Standards that would be in excess of state obligations under CAA § 110(a)(3)(D)(i)(I) by effectively writing them off. According to the commenter, the overcontrol created by these provisions is unreasonable and exceeds the EPA's authority under the Act.

Commenter (0523) states that a FIP addressing interstate transport of pollutants must also involve an appropriate degree of control, including sufficient controls to address the state’s contribution to downwind nonattainment, but no more control than is necessary to meet that requirement.

Commenter (0524) argues that without a clear nexus between the “enhancements” proposed by the EPA and significant contribution, the enhancements will lead to overcontrol. The commenter states that ongoing changes to its electric generating fleet as it adds more renewables as well as enhancements that limit the flexibility of the trading program could threaten electric reliability.

Commenters (0533, 0541) clarify that although they support the use of a trading program in general, the proposed “enhancements” are overly restrictive and result in unlawful overcontrol of regulated sources.

Although the commenter (0550) believes that the EPA's proposed "dynamic budgeting" approach is technically flawed and unlawful on its face, if the EPA does finalize such an approach, the EPA's proposal to treat its new budgets each year as a ministerial action is insufficient. The commenter says that the EPA's "dynamic budgeting" approach, as proposed, does not include any backstop to prevent overcontrol. Through the dynamic budgeting process, the EPA would essentially be proposing a new transport rule every year without confirming that future budgets will not require more reductions than are necessary to bring downwind receptors into attainment. The commenter recommends that the EPA perform a full analysis and provide for notice and comment of its new rulemaking each time it implements this process. According to the commenter, without a fulsome analysis and opportunity for comment, the EPA will have violated the Administrative Procedures Act (APA) and failed to confirm the resulting budgets would not result in unlawful overcontrol. Similarly, commenter (0533) states that if the EPA finalizes the dynamic budget approach, the commenter recommends that the EPA reevaluate its 4-step interstate transport framework analysis, including the modeling, for each recalculation of the state budgets, to ensure that states are not being overcontrolled.

Commenter (0550) states bank recalibration would require unnecessary reductions and limitations, which constitutes overcontrol. In the proposed rule, the commenter notes that the EPA states that its allowance bank recalibration is necessary to "prevent any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods." Even if the EPA later justifies "stringency" of controls as a synonym for "significant contribution," which it has not, the commenter states that the EPA's stringency goal is already accomplished through the assurance provisions. The commenter contends that the assurance provisions necessarily limit a states', and the corresponding sources in a state, freedom to emit materially in excess of its allocated budget and simply rely on banked allowances to make up the difference. Although states may exceed this assurance level, exceedances require an additional 3-for-1 allowance surrender. This surrender obligation by itself reduces any "surplus of allowances" that could become an issue if sources in a state attempt to ignore the overall stringency of the emissions budgets that reflect the EPA's determination of available cost-effective reductions. The commenter acknowledges that the EPA recognizes this, explaining that "[a]lthough the [existing] programs do not directly limit either trading or banking of allowances, 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." The commenter states that no further assurances, such as a banked allowance recalibration, are necessary to avoid this risk. According to the commenter, the EPA's efforts to further limit sources beyond what is necessary, *i.e.*, beyond the amount the EPA has determined is their "significant contribution," by taking away allowances the sources have earned through over-compliance constitute overcontrol and are unlawful.

Commenter (0554) states that the EPA's proposed enhancements eliminate the flexibility needed for an emissions allowance market to work, thus eliminating the benefits of the market. The multiple layers of backstop limits proposed, combined with new restrictions on the holding and use of allowances themselves, are likely to leave individual facility owners with too few choices for trading to function properly. While some constraints are needed to ensure the program accomplishes its intended goals and satisfies CAA requirements, unnecessary and duplicative constraints will impede the formation of a viable market and the associated benefits of trading. The combined effect of the many proposed enhancements is also likely to result in over-control, since the enhancements will tend to force greater emissions reductions than the levels the EPA evaluated in its over-control analysis. The commenter asks the EPA to "either eliminate the enhancements altogether or demonstrate how the proposed enhancements will not impede the development of a viable trading market and result in unlawful over-control."

Response:

These comments are responded to in Section V.D.4 of the preamble.

1.10 Venue under Clean Air Act (CAA) 307(b)

Comments:

Commenters (0262, 0326, 0407) object to the EPA limiting jurisdiction and venue of legal challenges to the United States Court of Appeals for the District of Columbia pursuant to 42 U.S.C. § 7607(b)(l) and believe that future petitioners should be able to challenge any final FIP in a more convenient and less costly venue. Commenters imply that this decision is based on an erroneous, unsupported conclusion that the proposed rule would be "nationally applicable" or, in the alternative, of "nationwide scope and effect." Commenter (0262) adds that Section 7607(b)(1) does not limit powers of courts but rather instructs petitioners as to where they should file. Commenter (0326) further adds that review of the EPA's infrastructure SIP actions by the D.C. Circuit would be improper because each action is a "prototypical . . . regionally applicable action."

Commenters (0262, 0326, 0407, 0760, 0798) disagree with the EPA's findings that the proposed action would be 'nationally applicable' within the meaning of CAA section 307(b)(1)" or, in the alternative, that "this action is based on a determination of 'nationwide scope or effect" within the meaning of CAA section 307(b)(1)," and request that the EPA reconsider the national applicability of the proposed rule. Commenter (0760) briefly recaps CAA section 307(b)(1) requirements – *e.g.,* noting that a petition for review of . . . any . . .nationally applicable regulations . . . may be filed only in the United States Court of Appeals for the District of Columbia. The commenters argue that it is well established that jurisdiction and venue determinations under CAA section 307(b)(1) are within the exclusive authority of the courts.

Commenters (0262, 0407, 0760) maintain that the EPA's findings of "national applicability" and "nationwide scope and effect" are not supported by the clear evidence and underlying documentation for the proposed rule. The commenters underscore the point that emissions limits applicable to non-EGUs sources were not uniformly applied – *e.g.,* only applied to 23 of the 25 states subject to the proposed rule, and emissions budgets for EGUs are unique to each state – *e.g.,* based on the characteristics and projected impacts unique to the regulated state.

Therefore, the commenters conclude that the proposed rule, as written, is not "nationally applicable."

Commenters (0262, 0760) suggest that implementation plans are by their very nature "locally or regionally" applicable; thus, as the proposed rule is an implementation plan with requirements tied to the individual characteristics of emissions sources within each state where controls are required, and it is not "nationally applicable" within the meaning of that term in the CAA, notwithstanding the EPA's assertion of national applicability. These commenters reference court rulings (*e.g., Texas v. United States EPA*, 829 F.3d 405 (5th Cir. 2016); *ATK Launch Sys. Inc. v. EPA*, 651 F.3d 1194 (10th Cir. 2011); *Madison Gas & Elec. Co. v. EPA*, 4 F.3d 529 (7th Cir. 1993)). All commenters urge the EPA to withdraw this finding in any final FIP issued pursuant to this rulemaking.

Commenter (0760) states it is well established that jurisdiction and venue determinations under CAA section 307(b)(1) are within the exclusive authority of the courts. *Texas v. Environmental Protection Agency*, 983 F.3d 826 (5th Cir.2020); *Lopez-Elias v. Reno*, 209 F.3d 788, 791 (5th Cir. 2000) (opining that "the determination of our jurisdiction is exclusively for the court to decide"); *Lindstrom v. United States*, 510 F.3d 1191, 1195 n.3 (10th Cir. 2007) ("Determining federal court jurisdiction is exclusively the province of courts regardless of what an agency may say." (internal quotes omitted)). *Smith v. AEGON Cos. Pension Plan,* 769 F.3d 922, 928 (6th Cir. 2014) (concluding that courts do not defer to agency interpretations when determining venue). Indeed, CAA section §307(b)(1) does not limit powers of courts but rather instructs petitioners as to where they should file. See *Dalton Trucking, Inc. v. EPA*, 808 F.3d 875, 878-80 (D.C. Cir. 2015) (holding that the section confers jurisdiction on all courts of appeal and divides venue among them).

Commenter (0262) says, to determine whether Section 7607(b)(1)'s narrow exception for locally or regionally applicable actions applies to the proposed rule, courts will ask de novo whether the "scope and effect" of the FIP is "nationwide." The chief question under the proposed rule is whether or not the term "scope and effect" refers to specific EPA factual determinations upon which the FIP is based, *i.e.*, the extent to which emissions from one state impact attainment goals in any other state. That question was answered definitively in *Texas v. United States EPA*, 829 F.3d 405 (5th Cir. 2016), where the Fifth Circuit observed that the EPA based its FIP on a number of intensely factual determinations that a certain state had not made reasonable progress towards its attainment goals solely because of emissions from facilities in another state, which consequently needed to be tightened. The court found that those factual determinations did not have "nationwide scope and effect" because they focused on the necessity to strengthen controls over only certain state-specific emissions. Therefore, the court held that the EPA's finding that the FIP as a whole had nationwide scope and effect was illegitimate. Accordingly, the Fifth Circuit refused to transfer the case to the D.C. Circuit. Id. at 421-24. So too, here the EPA's proposed rule is based on specific factual determinations that emissions from certain facilities in some states impact the ability of other states to meet their attainment standards. Such state-specific factual determinations do not qualify as ones of nationwide scope or effect. Id. Just as in Texas v. EPA, the determination of nationwide scope and effect in the proposed rule is illegitimate and cannot prevent petitioners from filing a challenge to the final rule in an appropriate court of appeals with authority over any region in which the implementation plan would apply. Accordingly, the EPA should rescind the proposed finding of nationwide scope and effect when it publishes the final rule.

Similarly, commenter (0760) says, The Fifth Circuit decision in another case involving the state of Texas and the EPA, *Texas v. United States EPA*, 829 F.3d 405 (5th Cir. 2016), is illustrative of a court's process for consideration of a challenge under CAA section 307(b)(1) venue based upon whether a proposed rule should be reviewed in that court, or in the D.C. Circuit. The court first considered whether the "scope and effect" of the FIP is "nationwide." The court considered whether the phrase "scope and effect" refers to specific EPA factual determinations upon which the FIP is based. In that case, the Fifth Circuit observed that the EPA based its proposed rule on a number of intensely factual determinations that a certain state had not made reasonable progress towards its attainment goals solely because of emissions from facilities in another state, which consequently needed to be tightened. The court found that those factual determinations did not have "nationwide scope and effect" because they focused on the necessity to strengthen controls over only certain state-specific emissions. Therefore, the court held that the EPA's finding that the FIP, as a whole, had nationwide scope and effect was incorrect. Thus, the Fifth Circuit retained jurisdiction rather than transferring the case to the D.C. Circuit (citing 829 F.3d 405, at 421-24). Just as in *Texas v. United States*, the EPA's proposed rule is based on specific factual determinations that emissions from certain facilities in specified states impact the ability of other specific states to meet their attainment standards at specific monitors. These are state-specific factual determinations that certainly do not qualify as ones of nationwide scope or effect. *Id.* Consequently, the Associations request that the EPA should rescind the proposed finding of nationwide scope and effect if and when it publishes a final rule in this proceeding.

Commenters (0760, 0798) assert that the proposal is not well founded; suggesting the FIP applies on a state-by-state basis and the EPA failed to make the state-specific assessments required for a proper review of each state's SIP and replacement with a FIP is not a justification for stripping the applicable regional courts of jurisdiction over what are inherently state-specific issues. Commenter (0760) states that the EPA made a finding of proposed disapproval of the Louisiana SIP in a joint action with its proposal to disapprove the Texas, Arkansas, and Oklahoma good neighbor SIPs, and states their belief that such action demonstrates that it is the relationship of these states that are at issue, not all states.

Commenter (0798) asserts that the EPA's use of a "common core of statutory and case law analysis, factual findings, and policy determinations" to find, what the commenter believes is a state-specific rule, has national applicability is inadequate. The commenter states that most state-specific rules the EPA promulgates are based on a "common core of statutory and case law analysis, factual findings, and policy determinations," which according to the commenter, is part of what prevents the EPA from acting arbitrarily and capriciously. The commenter contends that this is part of what prevents the EPA from acting arbitrarily and capriciously. If this were sufficient to make a state-specific rule nationally applicable, then almost all the EPA rulemaking would be forced into the D.C. Circuit for judicial review.

Response:

CAA section 307(b)(1) establishes two routes by which venue may be proper in the D.C.

Circuit. First, the D.C. Circuit is "the exclusive venue when EPA's challenged action is 'nationally applicable' rather than 'locally or regionally applicable.'" *Sierra Club v. EPA*, 47 F.4th 738, 742-43 (D.C. Cir. 2022). "Second, and alternatively, venue also lies exclusively in [the D.C. Circuit] if an otherwise 'locally or regionally applicable' action 'is based on a determination of nationwide scope or effect' and the EPA 'finds and publishes that such action is based on such a determination.'" *Id.* at 743. For the reasons provided below, this final action is nationally applicable. Alternatively, if a court finds this action to be locally or regionally applicable, the Administrator is exercising his complete discretion to find and publish that this action is based on a determination of nationwide scope or effect.

Nationally Applicable

To determine whether an action is "nationally applicable" or "locally or regionally applicable," a court "'look[s] only to the face of the agency action, not its practical effects.'" *Chevron U.S.A. Inc. v. EPA*, 45 F.4th 380, 386 (D.C. Cir. 2022) (quoting *Sierra Club*, 926 F.3d 844, 849). Venue turns on the nature of the agency "action," not the nature of a petitioner's challenge. *ATK Launch Systems, Inc. v. EPA*, 651 F.3d 1194, 1197 (10th Cir. 2011) (holding that "this court must analyze whether the regulation itself is nationally applicable, not whether the effects complained of or the petitioner's challenge to that regulation is nationally applicable"); *Texas v. EPA*, 829 F.3d 405, 419 (5th Cir. 2016) ("The question of applicability turns on the legal impact of the action as a whole"); *S. Ill. Power Coop. v. EPA*, 863 F.3d 666, 670 (7th Cir. 2017). On its face, this final rulemaking is "nationally applicable" because it directly applies to 23 states located in ten federal judicial circuits and in eight EPA regions across the entire continental United States.

Specifically, in this action the EPA is finalizing FIPs for 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 based on 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.*, the EPA's 4-step interstate transport framework for the 2015 ozone NAAQS). Among other things, these FIPs establish a single, interstate emissions trading program for EGUs in 22 of these states (excluding California), and also establish uniform emissions limits and associated compliance requirements for certain emissions units in nine non-EGU industries in 20 of these states (excluding Alabama, Minnesota, and Wisconsin).

Further, 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 the 4-step interstate transport framework and applying a nationally uniform approach to the identification of nonattainment and maintenance receptors across the entire geographic area covered by this final action. The EPA has also evaluated comments critiquing this modeling or calling for the use of alternative approaches or alternative sets of data with an eye to ensuring national consistency and avoiding inconsistent or inequitable results. The Agency has applied a nationally consistent approach to the evaluation of which emissions of upwind states should be deemed "significant" at Step 3 and therefore prohibited. In addition to its nationwide findings regarding EGU emissions control opportunities, the identification of other impactful industries, and the evaluation of cost-effective emissions control strategies for those industries, the EPA used an air quality assessment tool (AQAT) to undertake a nationally consistent evaluation of the air quality effects of different emissions control strategies.

Given that on its face 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 this action, this is a "nationally applicable" action within the meaning of CAA section 307(b)(1). This action derives from the EPA's "national interpretation" of CAA section 110(a)(2)(D)(i)(I) and "any challenge thereto belongs in the D.C. Circuit." *ATK Launch Systems, Inc. v. EPA*, 651 F.3d 1194, 1200 (10th Cir. 2011).

The EPA disagrees with commenters' suggestion that all EPA actions promulgating FIPs must be "locally or regionally applicable" actions subject to review in the regional circuit courts. We note that although the Administrator's promulgation of Federal implementation plans under CAA section 110(c) for multiple states under the good neighbor provision would constitute actions "promulgating [an] implementation plan under [CAA section 110]," judicial challenges to these actions have historically been heard in the D.C. Circuit Court of Appeals. Indeed, regional courts of appeals have transferred petitions for review of those FIPs or related actions on SIPs to the D.C. Circuit on at least two occasions over petitioners' opposition. *West Virginia Chamber of Commerce v. Browner*, 1998 WL 827315, at *6 (4th Cir. 1998); *Cedar Falls Utilities v. U.S. EPA*, No. 16-4504 (8th Cir. filed Feb. 22, 2017).

The EPA also disagrees with commenters' suggestion that this action is not nationally applicable because the EPA's proposed emissions limits for non-EGU sources would apply to only 23 states. An EPA action need not span from "sea to shining sea" to be nationally applicable. *Texas v. EPA*, 2011 WL 710598, *5 (5th Cir. Feb. 24, 2011) (finding SIP Call nationally applicable even though it "did not apply to every single state in the union"); *see also West Virginia Chamber of Commerce*, 1998 WL 827315, at *6.

Prior interstate-transport rules under the good neighbor provision covering numerous states but not the entire country, such as the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, were all litigated in the D.C. Circuit.

<u>*Nationwide Scope or Effect*</u>

Under CAA section 307(b)(1), an EPA action which is locally or regionally applicable may be filed only in the United States Court of Appeals "for the appropriate circuit" with one exception: if the locally or regionally applicable action (i) "is based on a determination of nationwide scope or effect," and (ii) the Administrator "finds and publishes that such action is based on such a determination," venue lies exclusively in the D.C. Circuit. The venue provision of the Act thus expressly grants the EPA complete discretion to determine whether to invoke an exception to the general rule that challenges to locally or regionally applicable actions be heard in the appropriate regional circuits. As the D.C. Circuit recently held in *Sierra Club v. EPA*, 47 F.4th 738 (D.C. Cir. 2022), the "EPA's decision whether to make and publish a finding of nationwide scope or effect is committed to the agency's discretion and thus is unreviewable."[11] Although "[a] court may review whether an action by the EPA is nationally applicable, as well as whether locally or regionally applicable action is based on a determination of nationwide scope or effect *when EPA so finds and publishes*…. A court may not 'second-guess' the agency's discretionary decision to make and publish (or not) a finding of nationwide scope or effect."[12] For these reasons, the EPA disagrees with commenters' claim that the EPA lacks discretion to make and publish a finding that this action is based on a determination of nationwide scope or effect.

As set forth in the preamble for this action, the Administrator is exercising the complete discretion afforded to him by the CAA to make and publish a finding that, if a court finds this action to be locally or regionally applicable, this action is based on a determination of "nationwide scope or effect" within the meaning of CAA section 307(b)(1). Thus, even if this action is locally or regionally applicable, challenges to it may only be brought in the D.C. Circuit. All of the factors discussed above that support the EPA's conclusion that this action is nationally applicable support the Administrator's finding that this action is based on a determination of nationwide scope or effect.

While commenters are correct that this action applies to states and sources in accordance with their various circumstances, our findings and the action we are taking with respect to each state and source are nationally consistent and based on determinations of nationwide scope or effect. The EPA therefore disagrees with commenters' arguments that this action is inherently state- or source-specific.

Additionally, 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.[13] 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.

Commenters fail to support their argument that courts do not defer to the EPA's determination

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[11] 47 F.4th at 745 (D.C. Cir. 2022); *see also Texas v. EPA*, 983 F.3d 826, 835 (5th Cir. 2020) ("when a locally applicable action is based on a determination of nationwide scope or effect, the EPA has discretion to select the venue for judicial review").

[12] 47 F.4th at 746 ("The Act offers 'no basis on which a reviewing court could properly assess' the agency's discretionary decision" to make a nationwide scope or effect finding) (emphases added).

[13] 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.

of venue. As the *Sierra Club* court noted, courts may review whether a locally or regionally applicable action is based on a determination of nationwide scope or effect *when EPA so finds and publishes.* But the decision whether to make and publish a finding of nationwide scope or effect is committed to agency discretion by law. Finally, contrary to commenters' claims, the EPA makes no determinations in this action regarding the jurisdiction of any court.

1.11 Miscellaneous Legal Issues

1.11.1 CAA Section 110(k)(6)

Comments:

Commenter (0326) states that the EPA's proposed action regarding rescinding the Delaware SIP approval conflates modeling updates with prior decisional errors in contravention of section 110(k)(5) of the CAA and should be withdrawn. The commenter asserts that the EPA is attempting to portray its modeling updates and new modeling results as creating an "error" as to its prior approval of a state's SIP to avoid the process prescribed in CAA section 110(k)(5) for when there is a finding that a SIP is substantially inadequate to attain or maintain the relevant NAAQS. The commenter provides background information regarding the EPA's approval of Delaware's SIP, noting that in 2020, the EPA approved an infrastructure SIP submission from Delaware for the 2015 ozone NAAQS, which in part addressed the good neighbor provision at CAA section 110(a)(2)(D)(i)(I). The EPA concluded that, based on the modeling results presented in a 2018 March memorandum and using a 2023 analytic year, Delaware's largest impact on any potential downwind nonattainment or maintenance receptor was less than 1 percent of the NAAQS. As a result, according to the commenter, the EPA found that Delaware would not significantly contribute to nonattainment or interfere with maintenance in any other state. Therefore, the EPA approved the portion of Delaware's infrastructure SIP that addressed CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Subsequent to the release of the modeling data shared in the March 2018 memorandum and the EPA's approval of Delaware's 2015 ozone NAAQS good neighbor SIP submission, the EPA performed updated modeling, which now shows that Delaware is projected to contribute more than 1 percent of the NAAQS to downwind receptors in Bristol, Pennsylvania, in the 2023 analytic year. Therefore, the commenter states that considering the modeling data, the EPA proposed to find that its approval of Delaware's 2015 ozone NAAQS infrastructure SIP submission, with regard only to the portion addressing the good neighbor provision at CAA section 110(a)(2)(D)(i)(I), was in error. Furthermore, the commenter states that in 2020, the EPA acted on a state SIP submittal that was supported by the modeling data that was available at the time, and the subsequent modeling results do not create an error regarding the EPA's prior action. According to the commenter, the EPA consistently updates models and releases new modeling platforms, and if all prior EPA decisions made with the support of modeling can be found to be retroactively "in error" once new modeling with new results occur, states and facilities across the United States will have no certainty or faith in the EPA's decision making. The commenter asserts that the EPA's approach and rationale for the proposed SIP disapprovals make it impossible for any SIPs a state might submit under the 2015 ozone standard or any future NAAQS to demonstrate compliance with CAA section 110(a)(2)(D) because not only must a state consider the evidence available at the time of submission, but a state must also possess the ability to consider future evidence that might demonstrate significant contributions to downwind nonattainment or interference with maintenance in a downwind state. The commenter further asserts that the CAA does not envision nor suggest that states be held to an impossible standard when developing SIPs and that section 110(k)(5) of the Act dictates the appropriate process for the EPA to follow should a state SIP later be found to be inadequate. The commenter states that the EPA's proposed attempt to avoid that process through the allegation that new modeling can create prior decisional error is arbitrary and capricious and should be withdrawn.

Commenter (0558) acknowledges that section 110(k)(6) of the CAA gives the EPA Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error; however, the commenter believes that CAA section 110(k)(6) is being applied inappropriately in this proposal, specifically as it relates to the withdraw of approval for Delaware's SIP. The commenter states that the determination that approval of a properly submitted and approved SIP was an error when new information is developed is a dangerous precedent for the EPA to establish. The commenter says that this approach not only does it undermine collaboration between the states and the EPA, but it will also create an unrealistic standard for states by requiring forecasting of future events not based on current modeling or data. The commenter further adds that successful collaboration between the EPA and the states requires the Agency to adhere to mandatory timelines and communicate openly with states throughout the SIP process, and that failure to do so will results in disjointed efforts between the EPA and states, as well as misdirected time and effort that could otherwise be used to focused on improving air quality, the environment and public health/welfare. In an effort to avoid these types of complications, the commenter urges the Agency to adhere to the statutory schedules for completing SIP review and approval.

Response:

While the EPA does not necessarily agree with the commenter's arguments regarding the scope of error correction authority under CAA section 110(k)(6), this issue is moot in this action because the EPA is not finalizing the proposed error correction for the state of Delaware. The updated 2016v3 modeling that the EPA is using to inform this final action indicates that Delaware is not linked to an out of state receptor. The EPA is therefore withdrawing the proposed error correction and proposed FIP for Delaware. See Section III.C.1 of the preamble.

1.11.2 Section 126

Comments:

Commenter (0323) urges the EPA to clarify that action under the "good neighbor" provision promulgating a FIP or approving a state SIP effectively prohibits CAA section 126(b) petitions addressing the same NAAQS. The commenter says that in this rule, the EPA attempts to create a cleared path for subsequent Section 126 petitions related the 2015 ozone

NAAQS "good neighbor" remedy as an effort to maintain, according to the commenter, a lawless opinion that the Agency's actions (in this case the proposed FIP) to remedy good neighbor SIP obligations are always open for review pursuant to CAA section 126. More specifically, the commenter claims that the EPA is improperly attempting to assert the Agency and downwind states have a continuously open-door policy to seek additional emissions reductions from upwind states related to SIP/FIP development, even after a complete remedy has been promulgated. The commenter quotes footnote 203 [87 FR 20095] as an example of the EPA misapplying court rulings (*Appalachian Power v. EPA*) in an effort to support their position. According to the commenter, if the EPA or a state has adopted adequate provisions that eliminate any significant contribution to nonattainment or interference with maintenance of the NAAQS in downwind states, there should be no grounds upon which a CAA section 126(b) petition could be granted. The commenters contends that only in the case of a petitioner producing new data or information not considered pursuant to a CAA section 110 SIP or FIP action, that a section 126(b) petition could be considered, and in such an event, the EPA would be obligated to evaluate the petition to determine if it raises new information that merits further review.

Commenter (524) requests that the EPA include language in the preamble that clarifies action under the CAA good neighbor provisions effectively precludes action under section 126 of the CAA.

Response:

It is the EPA's expectation at this time that this rule constitutes a complete remedy resolving good neighbor obligations for the 2015 ozone NAAQS for the covered states. However, the EPA cannot and will not prejudice its determination in hypothetical future actions where a petitioner under CAA section 126(b) may seek a finding under facts and circumstances not evident to the Agency in this action that prohibited significant contribution for purposes of the 2015 ozone NAAQS is in fact continuing. As the EPA explained at proposal, we have 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). Thus, this position is no different than our existing policy and nothing in this action affects or modifies that pre-existing view.

1.11.3 Other

1.11.3.1 Replacing the FIP with SIPs

Comments:

Commenter (0372) contends that the proposed FIP unlawfully limits the ability of states to depart from the FIP by not providing a meaningful opportunity for states to exit the CSAPR-FIP process via a flexible off-ramp option, and in so doing, unlawfully appropriates state discretion to address good neighbor obligations, departing from statutory framework set by

Congress. The commenter asserts that the EPA constrains states that chose to submit non-CSAPR SIP Revisions to a standard of "whether 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" by the state sources; thus, unlawfully narrowing the avenues in which states may propose. The commenter says that if states participate in the CSAPR program per the FIP, then their SIP optionality is virtually eliminated by operation of law (40 CFR 52.38(a)); therefore, non-CSAPR SIP revisions are states' only real option as a true off-road from this FIP for EGUs.

Response:

This comment is responded to in Section VI.D of the preamble.

1.11.3.2 Inconsistency with Reasonably Available Control Technology (RACT)

Comments:

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0798) argue it is unreasonable, unlawful, and inconsistent with both the EPA's past practice and court precedent interpreting the good neighbor provision to subject upwind states to emissions limits that are stricter than the RACT limits imposed in the downwind states. Whatever requirements are placed on upwind industry should not be more stringent than those applicable to industries subject to RACT due to actually being in a nonattainment area; it would be irrational, arbitrary, and capricious, when considering impacts to the same nonattainment or maintenance receptor, to force a source far away to enact stricter limits than a source actually in or next door to the nonattainment area. Such a requirement for commenter (0337) would cost hundreds of millions of dollars and would be catastrophic to the company. It would likewise far-exceed the EPA's authority under the "good neighbor" provisions of the CAA and would render any such action as arbitrary and capricious.

Response:

The EPA disagrees that the statute limits the EPA's determination of what may constitute "significant contribution" under CAA section 110(a)(2)(D)(i)(I) only to those measures that have been found to be "RACT" for downwind nonattainment areas. Nonetheless, the emissions control requirements finalized in this rule for both EGU and non-EGU industry sources are generally commensurate with the stringency of emissions controls many downwind states have already required of similar sources located within ozone nonattainment areas or in the northeastern Transport Region (OTR) pursuant to RACT requirements for NO_X. In addition to NO_X RACT, the EPA's review and determination of cost-effective achievable emissions reductions from non-EGU industrial sources in this action was also informed by review of permits, CDs, new source performance standards (NSPS), and other sources of information.

Further, the commenter's complaint draws an apples-to-oranges comparison by suggesting that the EPA is requiring more of upwind states in this rule than the CAA requires of downwind receptor areas. This is not necessarily the case even with respect to NO_X RACT. However, we note that ozone nonattainment areas also face other nonattainment planning requirements under subpart 2 (depending on classification), such as volatile organic compound (VOC) RACT, NNSR requirements, and various mobile-source measures. The EPA is not requiring such measures of upwind states under the good neighbor provision in this action. We have focused in this rule on large, stationary sources of NO_X because the data indicates that these emissions reductions deliver the most cost-effective means of reducing regional-scale ozone transport. We have noted in determining the appropriate level of emissions control at Step 3 that these control measures are roughly commensurate to what similar sources in downwind areas face; we have not claimed, nor need we establish, that the requirements are perfectly identical.

Where commenters supplied information demonstrating that the proposed emissions limits for certain types of units were in fact not feasible or not demonstrated to be applicable on similar unit types, the EPA has adjusted the final rule in response or has determined not to finalize such requirements at all. See Section VI.C of the preamble for further discussion of these changes.

1.11.3.3 Applicability of CAA Section 112(n)(1)(A)

Comments:

Commenter (0798) claims that the EPA's approach to "baking-in" co-benefit considerations is arbitrary because it is incompatible with the EPA's current promulgated final rule assessing the appropriateness of accounting for co-reductions of pollutants, other than the pollutant subject to a particular regulation. The commenter states that when assessing the appropriateness of taking into account benefits of non-hazardous air pollutant (HAP) reductions in the context of the CAA's HAP regulations under section 112, the EPA previously found that "the EPA's equal reliance on the PM air quality co-benefits projected to occur as a result of the reductions in HAP was flawed as the focus of CAA section 112(n)(1)(A) is HAP emissions reductions….Indeed, it would be highly illogical for the Agency to make a determination that regulation under CAA section 112, which is expressly designed to deal with HAP, is justified principally on the basis of the criteria pollutant impacts of these regulations. That is, if the HAP related benefits are not at least moderately commensurate with the cost of HAP controls, then no amount of co-benefits can offset this imbalance for purposes of a determination that it is appropriate to regulate under CAA section 112(n)(1)(A)" [84 FR 2675]. The commenter acknowledges that CAA sections 112(n)(1)(A) and 110(a)(2) are separate statutory schemes, however, the commenter feels that the cost/benefit analysis must be treated consistently because both treatment of cost under each provision is based on the same question: whether a given regulation is "appropriate" and "necessary." The commenter concludes that because the Ozone NAAQS is focused on ozone reductions, any "good neighbor" implementation plan under the Ozone NAAQS should also only be considered "appropriate" if the ozone benefits are commensurate to the costs, without relying on co-benefits from $PM_{2.5}$ reductions and climate considerations, since both are outside the scope of the ozone NAAQS.

Response:

This action is not justified on the basis of co-benefits resulting from reductions in non-target pollutants that may occur in response to the action, as projected in the economic analysis provided in the RIA accompanying this final rule. This action addresses CAA section 110(a)(2)(D)(i)(I) for covered upwind states through eliminating those emissions of ozone-precursor pollutants that the EPA finds significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS.

1.11.3.4 Administrative Procedures Act (APA)

Comments:

Commenters (0306, 0365, 0504) declare that the EPA does not have the authority to change policy positions and adopt new regulatory interpretations, without first complying with APA procedures, under which "a reviewing court shall . . . hold unlawful and set aside agency action, findings, and conclusions found to be . . . arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." Commenter (0306) lists multiple reasons specific to the state of Texas (failure to adequately consider the difficult supply chain and bottleneck issues, failure to adequately consider costs, failure to consider Texas's prosperity, its long-term growth, the well-being of its populous, etc.), why the proposed rule is arbitrary and capricious and an abuse of the EPA's discretion, in violation of the APA. 5 U.S.C. § 706(2)(A). Commenter (0504) adds that APA requires agencies to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" The commenter concludes that while "agency action representing a policy change" need not be "justified by reasons more substantial than those required to adopt a policy in the first instance," it remains bounded by "the requirement that an agency provide a reasoned explanation for its action."

Response:

While this action largely applies the same 4-step interstate transport framework the EPA has previously applied to interstate ozone transport for earlier ozone NAAQS revisions, in certain instances within that framework, the EPA in this rule has made changes in its approach reflective of the more protective 2015 ozone NAAQS, accounting for updated information, in response to comments, or reflective of experience with prior transport rulemakings. The EPA has adequately explained elsewhere in the record each instance where it has made those adjustments, has provided explanations for why it has done so, and has evaluated the consequences of those changes. For purposes of this action, which among other things promulgates FIPs under the CAA, this standard of review is supplied by CAA section 307(d)(9), not the APA. *See* Section X.L of the preamble. This comment otherwise lacks reasonable specificity and the EPA is unable to respond further to the broad assertions made here.

1.11.3.5 Infrastructure Investment and Jobs Act (IIJA) - H.R.3684

Comments:

Commenter (0435) believes that finalizing the proposal would also impede the successful implementation of the Infrastructure Investment and Jobs Act (P.L. 117-58) (IIJA). The commenter observes that the affected types of industrial sources covered by the proposal include those in the natural gas, cement, iron, steel, and other sectors vital to nation's economy - but particularly important to the success of IIJA. The commenter provides some additional background information on the IIJA, which the commenter describes as an historic investment in our nation's infrastructure, and expresses concerns that inflation will impact prices and constrain production and use of American-made materials such as steel and concrete.

Response:

This comment lacks reasonable specificity as to how this action conflicts with the IIJA (P.L. 117-58).

1.11.3.6 Role of Consent Decrees

Comments:

Commenters (0300, 0365) urge the EPA to avoid litigation and move away from consent decrees that often stipulate actions and timing/schedules to be taken by Agency in lieu of CAA requirements, without obtaining proper input from stakeholders (*i.e.*, states, the regulated community, lawmakers, or the public) by instead adhering to CAA statutory deadlines. Commenter (0300) notes they publicly expressed concern with these practices on April 4, 2015, when Mississippi Department of Environmental Quality Air Division Director Dallas Baker testified in front of the U.S. Senate Committee on Environment and Public Works. According to the commenters (0300, 0365), these consent decrees, as in the case of Downwinders at Risk et al. v. Regan, often place the EPA and the states in adversarial roles, as opposed to collaborative roles as envisioned by the CAA; partly due to states' inability to provide input on the development and timing of the new (*i.e.*, alternative to the CAA) path forward. The commenters imply that the EPA often cites these consent decrees as a reason for lack of interagency cooperation and rushed decision making – to rationalize the disapproval of Mississippi's SIP and suggests that the CAA was designed for states and federal agencies to work in tandem.

Commenter (0365) believes that the EPA uses a very broad and sweeping interpretation of its powers under 42 U.S.C. § 7401 et seq. to propose this rulemaking.

Commenter (0284) notes that the EPA was only required to approve or disapprove SIPs by April 30, 2022, not to issue a FIP by that time.

Commenter (0300) opposes the use of consent decrees, which it describes as "sue-and-settle," and argues that they exclude states from deliberations and create tight deadlines that result in rushed decision making and a lack of interagency cooperation. Commenter states that the requirements outlined by the CAA for the EPA to work collaboratively with the states are not trumped by the EPA entering into consent decrees, and the EPA should not use the consent decree to justify the quick disapproval of SIPs and implementation of the proposed FIP.

Commenter (0323) objects to the time frames agreed upon in the Consent Decree entered in *Downwinders at Risk et al. v. Regan* and notes that the CAA does not mandate the promulgation of a FIP in such a short time frame. Commenter (0531) adds that "EPA has no statutory obligation to expedite this proposed rule but agreed to the accelerated schedule in a voluntary settlement agreement without regard to comments and objections of affected states and the regulated community. The EPA entered into this voluntary settlement agreement despite a presidential order which was in effect at the time which had ended this practice."

Commenter (0398) states that the short timeline resulting from the Consent Decree does not give states the opportunity to address deficiencies identified by the EPA. Commenter adds that if the EPA goes forward with its proposed SIP disapprovals and implements the proposed rule, "EPA must allow the state adequate time to evaluate the new underlying data that the EPA is primarily relying upon to support its proposed Transport SIP disapproval. The EPA must also allow adequate time for the state to develop any supplemental demonstrations or revisions to address the new data before finalizing a federal plan."

Commenter (0284) notes that the EPA was only required to approve or disapprove SIPs by April 30, 2022, not to issue a FIP by that time.

Commenter (0289) writes that if the EPA were to withdraw the proposed rule, it would not technically violate the court ordered deadlines. "EPA did in fact sign the proposed FIP by February 28, 2022. The Consent Decree does not include any stipulations that would eliminate the extension the EPA received by signing the proposed FIP should the EPA decide to withdraw it and re-propose it at a later date after it has finalized its actions on the submitted SIPs. Doing so would also preserve the Congressional intent of CAA section 110(c)(1)(B)."

Commenter (0289) writes that although comments were submitted to the docket for the proposed Consent Decree, the EPA never offered a summary of those comments or any responses to them before executing it on January 12, 2022. Commenter writes that the EPA must address those comments before it can finalize this action and explain why it decided not to provide any responses or notice that it had considered the comments it received before executing the Consent Decree. The commenter concludes that "Failure by EPA to withdraw the proposed FIP would imply that the EPA is intentionally ignoring relevant technical facts and issues brought up in comments on the SIP disapprovals that also have significant bearing on EPA's proposed FIPs in this action. It would also imply EPA intent to subvert and diminish the opportunity for a meaningful public participation process for the proposed FIPs it plans to impose on the affected states."

Commenter (0365) writes that the Consent Decree entered in Downwinders at Risk et al. v. Regan presumes the result of the EPA's consideration of state SIP submissions prior to public notice and comment procedures.

Response:

Comments regarding judicial consent decrees are beyond the scope of this action. However, we note that the EPA was not prejudiced in the substance of this action, or any related action, by any CD resolving legal claims alleging the Agency had not met mandatory statutory deadlines under the CAA. The *Downwinders At Risk et al.*, *New York et al.*, and *Our Children's Earth Foundation* consent decrees did not require the EPA to promulgate final FIPs for any state but only provided the terms by which the EPA must act on certain SIP submittals. See Section III.B.2 of the preamble. The EPA is also subject to a CD deadline of March 15, 2023, to promulgate FIPs for Utah, Pennsylvania, and Virginia. *Sierra Club et al. v. Regan*, No. 3:22-cv-01992 (N.D. Cal.). That CD also provides that the EPA may discharge that obligation through the approval of SIPs, if that were appropriate. The provisions of these consent decrees do not deviate from the principles or process that DOJ and the EPA routinely apply in resolving CAA deadline suit litigation. The EPA published notice and received comment on these consent decrees before finalizing them as required by CAA section 113(g). The commenter has not explained with reasonable specificity how any of these consent decrees are contrary to agency or presidential policy, nor would any such intra-Executive Branch policies be enforceable by external parties, and in any case such issues are beyond the scope of this action.

1.11.3.7 Justification for Global Perspective on Climate Damages

Comments:

Commenter (0765) states that the CAA, National Environmental Policy Act (NEPA), APA, and other key sources of law not only permit, but in fact require the EPA to consider international effects, and recommends that the Agency highlight these legal requirements as justification for its focus on global climate impacts. The commenter references and briefly discusses a few sections (Sections 108 and 202) of the CAA, and related provisions (Title I) as support. Next, the commenter briefly describes the intent of NEPA, and concludes that under NEPA, the EPA is required to interpret all of its laws in ways that recognize the worldwide character of environmental problems, and suggests that using global social cost of greenhouse gas estimates helps fulfill that requirement. The commenter believes that other legal commitments, like the United Nations Framework Convention on Climate Change share this conclusion.

The commenter further argues that under the APA, it is arbitrary and capricious for agencies to "entirely fail[] to consider an important aspect of the problem" — an obligation that a federal court held requires federal agencies to consider international climate impacts. As support, the commenter cites a recent ruling from the U.S. Court for the Northern District of California, which struck down (as arbitrary) the Bureau of Land Management's rescission of the Waste Prevention Rule, in part because the agency had abandoned the Working Group's peer-reviewed, global estimates of the social cost of greenhouse gases in favor of flawed estimates that looked only at effects within the U.S. borders [Bernhardt, 472 F. Supp. 3d at 613].

Response:

These comments relate to the methodology by which the EPA applies a social cost of greenhouse gases (SC-GHG) as a part of an assessment of the overall projected effects of an action in regulatory impact analysis (RIA), as required by Executive Order 12866 and other executive orders. This action implements the requirements of CAA section 110(a)(2)(D)(i)(I) to prohibit emissions that significantly contribute to nonattainment and interfere with maintenance of the 2015 ozone NAAQS in other states. The action is not justified by ancillary effects it may have with respect to other beneficial environmental or public health outcomes.

With respect to the climate benefits assessment in the RIA, we note that before the proposal of this rule, the U.S. District Court for the Western District of Louisiana issued a preliminary injunction concerning the monetization of the benefits of greenhouse gas emissions reductions by the EPA and other defendants. See *Louisiana v. Biden*, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values were not presented in the benefit-cost analysis of the proposal conducted pursuant to E.O. 12866.

The injunction was subsequently stayed on appeal to the Fifth Circuit while the proposal package was in interagency review. The EPA then prepared an addendum to the RIA titled "2015 FIP Climate Benefits Technical Memo," which is available in the docket, EPA-HQ-OAR-2021-0668-0193. The EPA quantified the anticipated monetized climate benefits of the proposal in this technical memo using the February 2021 Interim SC-GHG estimates.

For the RIA, the EPA continues to use the February 2021 Interim SC-GHG estimates, presenting benefits calculated using a 5 percent, 3 percent, 2.5 percent and 3 percent (95^{th} percentile value) discount rate. See Chapter 5.2 of the RIA.

2 Proposed Rule Approach

2.1 4-Step Approach

Comments:

Commenter (0523) argues that the EPA's one-size-fits-all approach to the non-EGU provisions of the proposed rule presents significant questions about whether it exceeds the Agency's authority under the good neighbor provision of the CAA. Furthermore, the commenter states that in addition to cost-effectiveness and over-control issues, even in the context of a FIP, the EPA likely does not have authority to impose such specific control measures on a state. (see Virginia v. EPA, 108 F.3d 1397, 1408 (D.C. Cir. 1997)). According to the commenter, regulation of several industries across a region is fundamentally more complex than establishing a region-wide emissions trading program for a single industry. The commenter states that with a trading program, such as the CSAPR, it is comparatively easy to confirm that the reductions required by an individual state are proportionate to its contribution to downwind nonattainment, but it is far more challenging to impose region-wide emissions control requirements across a number of different industries while ensuring that each state bears its fair share – and only its fair share – of the burden. The commenter remarks that the proposed rule effectively establishes a suite of region-wide obligations, regardless of any individual state's contribution to nonattainment, the presence of identified non-EGU source categories within that state, or the degree to which the selected targets of the rule will result in a degree of control within each state that is proportional to that state's contribution to downwind nonattainment. The commenter continues that the EPA calculates the emissions reductions projected to result from the proposed rule in each state in its Regulatory Impact Analysis, as well as the change in ozone levels at various downwind receptors projected to result from the rule, but it is not clear that the EPA specifically establishes that the emissions reductions in each upwind state resulting from the proposed rule's combined EGU and non-EGU measures are the minimum amount necessary to achieve attainment at each downwind receptor to which the upwind state is linked.

Commenter (0361) claims that the proposed rule exceeds the EPA's authority because the FIP is drastically more stringent than the previous rule, fundamentally alters the methodology used to calculate the relevant state budgets, provides direct command-based directives to adopt certain post-combustion measures, and fails to contemplate essential considerations for formulating a trading program that complies with the terms of the CAA and current precedent. The commenter adds that the proposed rule also contains erroneous projections and modeling assumptions that will significantly impact any state budget amounts. According to the commenter, these modeling errors will also seriously distort the cost-benefit analysis involved in requiring certain post-combustion measures. The commenter suggests that the EPA dispense with the command-and-control elements of the proposed rule that undermine the flexibility inherent in the cap-and-trade structure. The commenter requests that the EPA remove the technology-specific mandates, reexamine the assumptions and models on which the proposed budgets are based, and correct them where needed

Commenter (0518) stated that the EPA's proposed controls on non-EGUs at Step 4 fail to follow a reasonable framework for addressing transport and are vulnerable to overcontrol.

According to the commenter, these proposed controls on non-EGUs at Step 4 are based on the elements of the EPA's Step 3 analysis that the commenter asks the EPA to reconsider. The commenter urges the EPA not to proceed with finalizing the proposed controls for non- EGUs and, at a minimum, conduct a reassessment at Step 3 and reevaluate the applicable sources and highly cost-effective available controls for non-EGUs. The commenter further urges the EPA to reconsider its approach at Step 4 because the Agency has not followed the required equitable framework the Supreme Court reinforced for the good neighbor provision, in Homer City, where the Supreme Court reinforced it was reasonable for the EPA, when deciding which "amounts" among otherwise equal transport emissions to address, to "reduce the amount easier, *i.e.*, less costly, to eradicate." The commenter also claims that the EPA has created a framework whereby the cost per ton of the EPA's proposed controls across the upwind states is neither uniform nor equitable. For instance, according to the commenter, the proposed controls for Tier 1 non-EGUs would impose an average annual cost per ton of $5,213 in Kentucky but $1,571 in Wisconsin. The commenter asserts that the EPA's proposed controls for non-EGUs also apply an inconsistent approach across sources that is not sufficiently explained. For example, the commenter remarks that while all seven of the non-EGU industries would be subject to the proposed NO_X emissions limits, cement kilns under the Tier 1 non-EGU industry North American Industry Classification System (NAICS) 3273 is the only non-EGU industry that would inexplicably be subject to an additional source cap limit expressed in a ton per day of NO_X for each plant under the proposed section 52.42 requirements. The commenter states that the record fails to support the source cap limit, and the EPA has failed to explain how such controls for one industry within the same designed grouping is considered equitable. According to the commenter, this example further displays the inconsistent approach the EPA has taken with respect to non-EGUs in which the Agency fluctuates between a sector-specific focus and that of high-level grouping by tier, NAICS, or more generalized non-EGU umbrella. The commenter adds that the EPA's proposed controls for non-EGUs include those that are infeasible and would lead to overcontrol. The commenter provides the example of electric arc furnaces (EAFs), for which the EPA proposed the installation of SCR which has never been used on an EAF and is impossible to apply at EAFs. The commenter states that this and other errors call into question other potential areas of oversight by the EPA's rush to issue this rulemaking. The commenter further contends that the EPA's proposed controls for non-EGUs do not have parity with the controls on EGUs, noting that the EPA estimated average air quality improvements at downwind receptors in 2026 for non-EGUs was an average 0.18 parts per billion (ppb) for Tier 1 industries and 0.04 ppb for Tier 2 industries compared to an average combined 0.43 ppb improvement from EGUs. The commenter states that the EPA provides little discussion of how the Agency justifies these controls given the insignificant level of improvement to downwind receptors compared to EGUs. With regards to cost comparisons, the commenter asserts that the EPA's cost- effective threshold for non-EGUs is fundamentally flawed due to errors in its screening assessment, including assumed controls for sources that are impossible to install and estimated costs of controls that were not accurate, which is not the case for the well-established understanding of the available controls and data for EGUs. The commenter stresses that to ensure the EPA is following the equitable framework required to address transport emissions, the EPA must provide a more thorough explanation of the manner in which it has balanced controls between EGUs and non-EGUs.

Commenter (0798) asserts that the EPA treats EGUs and non-EGU sources in fundamentally different ways, many of which directly conflict with past EPA determinations and court decisions without reasonable explanations for departure. According to the commenter, these include, but are not limited to the following:

- Setting statewide budget limits for EGUs, while instead subjecting non-EGUs to unit specific command and control limits without any evaluation of how the proposed limits relate to the amount of statewide reductions needed to eliminate a state's alleged substantial contribution;
- Allowing emissions trading for EGUs, but not for non-EGUs;
- Accounting for feasibility in evaluating applicability of EGU provisions to types of EGUs and which states to subject to the EGU provisions, but not performing any feasibility analysis, much less facility or unit specific feasibility analysis, non-EGU industries;
- Modeling impacts and cost effectiveness of controls for EGUs as a single industry, but grouping all other covered industries together as "non-EGUs" for a single cost effectiveness analysis;
- Modeling the effect of multiple cost thresholds for EGUs as an industry ($1,600, $1,800, and $11,000) to evaluate whether lower cost thresholds could achieve sufficient reductions, but only modeling a single cost threshold ($7,500) for all non- EGUs.

Proposed controls at Step 4 fail to follow a reasonable framework for addressing transport, lack sufficient support in the record, exclude reasonable options for sources to comply, and lead to overcontrol of some upwind states.

Commenter (0798) asserts that in determining what non-EGUs to regulate, the EPA did not correctly follow the "4-step interstate transport framework" used by the EPA in prior rulemakings and approved by the Supreme Court. The commenter remarked that rather than evaluate the upwind emissions that actually contribute to each screened-in state's linked nonattainment or maintenance receptors, the EPA instead just (1) identified industries nationwide that contributed relatively more than other industries, and (2) automatically mandated limits directly on all such industries in each screened-in state, skipping any finding that the industries (let alone specific sources) actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state. The commenter adds that the resulting proposed rule imposes limits on NO_X emissions that the EPA's own analysis acknowledges have never been demonstrated in the iron and steel industry and cannot be met by any technology currently available for use in the iron and steel industry. According to the commenter, many of the technologies proposed by the EPA to control NO_X (*e.g.*, SCR, nonselective catalytic reduction (NSCR)) are not technically feasible for the emissions units included under the proposed rule. The commenter notes that even if technology used in wholly dissimilar industrial processes were able to be implemented, the costs would be significantly higher than the thresholds the EPA relied upon for screening out available control technologies. The commenter further states that the EPA also assumes that low NO_X burners are an available technology for certain emissions units to reduce NO_X emissions, completely ignoring the fact that many of these units already incorporate low NO_X burner technology. The commenter adds that associated production downtimes to add controls also would have severe economic consequences for the industry. Furthermore, the commenter contends that efforts to adapt these technologies to the iron and steel industry would increase emissions of other pollutants and require re-engineering and modifications to not only the steel making process, but also existing air pollution control equipment. The commenter relates that the addition of ancillary equipment to address flue gas characteristics and the batch nature of the steelmaking process would drive up costs and have both upstream and downstream impacts that would not have been accounted for in the original equipment design specifications. Further, the commenter remarks that the proposed rule also makes assumptions regarding equipment availability and constructability that cannot be reconciled with present and future supply chain considerations and threatens to hamstring the economy and national security with extended downtime or closures and resultant shortages of domestic iron and steel supply. The commenter states that the proposed rule attempts to go well beyond the EPA's authority under the CAA, and the EPA risks legal challenges to any final rule in the same form as the proposed rule that will restrict the EPA's discretion in future rulemakings. The commenter also believes that the EPA's decision to make the proposed rule apply on a unit specific basis directly to facilities means every covered facility will have the ability to challenge the applicability of the proposed rule's limits as applied to that facility, likely jettisoning the uniformity that the EPA purports to seek in the proposed rule and stringing out any rulemaking in constant challenges. For these reasons, the commenter urges the EPA to withdraw the proposed rule in favor of allowing states the opportunity to correct any concerns that the EPA may have with their SIP submittals and in the alternative for the EPA to correct the errors that have been identified with respect to its proposed rule. The commenter requests to be involved in a stakeholder process if the EPA makes significant changes to the proposed rule, and to have adequate to review and comment on any changes.

Commenter (0550) remarks that emissions from EGUs are not significantly contributing to downwind nonattainment and maintenance. The commenter states that the EPA cannot continually reiterate its 4-step interstate transport framework process without evaluating whether the framework is still a reasonable approach, particularly given that cost-effective reductions from EGUs have already been identified and budgets have been imposed to ensure those cost-effective reductions are made. According to the commenter, the logic of the EPA's prior 4-step framework "stops at the point where EPA is no longer effectuating its statutory mandate."

Commenter (0395) writes that the proposed rule has "vanishingly small effects on interstate ozone but would force premature closure of fossil fuel-fired EGUs and threaten electric grid reliability," which exceeds the EPA's authority under the CAA. Commenter claims the EPA plainly intends to cause a significant number of coal and gas-fired power plants to shut down. This interpretation is in alignment with the current Administration's stated goal of a net-zero electric sector by 2035, and this Proposal appears to be a back-door approach to reducing carbon emissions to further that goal. If the proposed rule were limited to the EPA's CAA authority, the EPA would have proposed cost-effective, feasible ozone reduction strategies that are limited to redressing significant contributions to ozone from upwind states instead of proposing to dramatically reduce CSAPR allowances reflecting retrofit of SCR at 26 Texas power plants such that, by the EPA's own modeling projections, the majority of these plants will not install controls and will therefore no longer be able to supply power during the peak demand season.

Response:

Responses to these comments are provided in Sections III, IV, and V of the preamble. The basis for the EPA's overall rule approach is in Section III. The discussion of ozone nonattainment and maintenance issues and which states contribute to those receptors is in Section IV. The analysis of emissions control opportunities, the identification of which emissions reductions are justified, and the downwind air quality effects of those emissions reductions are in Section V.

Comments:

Commenter (0367) remarks that the EPA's proposal applies a settled 4-step interstate transport framework using cost-effectiveness to apportion required emissions reductions among upwind states. The commenter notes that the proposal continues an approach upheld in *EME Homer City*, in which the Supreme Court explained that the EPA's 4-step interstate transport framework was a permissible method of apportioning the required amount of emissions reductions necessary to eliminate upwind states' "significant contributions," and added that the Court elaborated that the EPA's approach reasonably allows the agency to "achieve levels of attainment . . . at a much lower overall cost." Commenter (0367) remarks that the EPA's proposal applies a settled 4-step interstate transport framework using cost-effectiveness to apportion required emissions reductions among upwind states. The commenter notes that the proposal continues an approach upheld in *EME Homer City*, in which the Supreme Court explained that the EPA's 4-step interstate transport framework was a permissible method of apportioning the required amount of emissions reductions necessary to eliminate upwind states' "significant contributions," and added that the Court elaborated that the EPA's approach reasonably allows the agency to "achieve levels of attainment . . . at a much lower overall cost."

Response:

The EPA agrees that the final rule applies the 4-step interstate transport framework process for addressing interstate transport obligations under the CAA. This rule finalizes emissions reductions as required to fully eliminate upwind states' significant contributions of interstate ozone transport for the 2015 ozone NAAQS.

Comment:

Commenter (0367) remarks that the EPA's proposal applies a settled 4-step interstate transport framework using cost-effectiveness to apportion required emissions reductions among upwind states. The commenter notes that the proposal continues an approach upheld in *EME Homer City*, in which the Supreme Court explained that the EPA's 4-step interstate transport framework was a permissible method of apportioning the required amount of emissions reductions necessary to eliminate upwind states' "significant contributions," and added that the Court elaborated that the EPA's approach reasonably allows the agency to "achieve levels of attainment . . . at a much lower overall cost."

Commenter (0504) has significant concerns with the EPA's analysis and technical support in Step 1 and Step 2 of this framework, which are not specific to non-EGU sources. However, the commenter states that in contrast, Steps 3 and 4 demonstrate that the EPA's 4-step interstate transport framework is ill-suited to, and fundamentally unworkable for, non-EGU sources – particularly EAF steel producers.

Response:

The EPA disagrees that Steps 3 and 4 of the 4-step interstate transport framework are not suitable for application to non-EGU sources. As discussed in Section III.B.1 of the preamble, the framework represents a methodology for determining significant contribution and necessary emissions reductions to eliminate significant contribution, regardless of source type. However, for separate reasons explained in Section VI.C.3 of the preamble, the EPA is not finalizing the proposed emissions limitations for electric arc furnaces in iron and steel manufacturing.

Comment:

Commenter (0506) declares that the EPA's proposal correctly applies the 4-step interstate transport framework, and the EPA should use this process in the final rule. The commenter notes that allowance prices for both Group 2 and Group 3 have increased substantially since early 2022, likely for a variety of reasons. According to the commenter, the net result is that allowance prices through early June 2022 have traded well above the variable cost of optimizing and running post-combustion NO_X controls. The commenter opines that unit-level emissions data will likely indicate that operators have appropriately responded to the allowance price signal and mitigated NO_X emissions to the fullest extent possible.

Response:

The EPA is finalizing the 4-step interstate transport framework presented in the proposed rulemaking. Reasons why existing Group 3 allowances may have traded at higher prices in 2022 are beyond the scope of this rulemaking; we are confident for reasons explained in Section V and 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 EGU NO_X Mitigation Strategies Final Rule TSD, that our cost estimates for this rule are reasonable. See also Section 4.3 (Control Stringencies by Cost Threshold and Corresponding Emissions Reductions) of this document for further response to comment on issues related to cost assumptions at Step 3.

Comment:

Commenter (0518) stated that the EPA's approach to the 4-step interstate transport framework in the proposed rule is flawed and warrants reconsideration. The commenter recommends that the EPA stay action on the proposed rule with respect to non-EGUs to collect sufficient data, conduct updated analyses, and allow stakeholders time to consider and evaluate the modeling on which the EPA has relied upon. The commenter also recommends that the EPA defer action under Step 1 of its 4-step interstate transport framework until the ongoing attainment designation process for the 2015 ozone NAAQS concludes. Another recommendation from the commenter is for the EPA to reevaluate its non-EGU screening assessment at Step 3, in which the EPA fails to follow its own guidance in using a "simplified" AQAT, erroneously aggregates distinct sources and types of emissions activities using industry NAICS codes, applies arbitrarily low thresholds that fail to reasonably demonstrate highly cost-effective controls for addressing significant contribution, and ignores feasibility issues and current economics that limit sources' ability to comply by the attainment deadline. Further the commenter states that the EPA should revisit the proposed controls on non-EGUs at Step 4, which fail to follow a reasonable framework for addressing transport, lack sufficient support in the record, exclude reasonable options for sources to comply, and lead to overcontrol of some upwind states.

Response:

The EPA received numerous public comments on non-EGU regulatory requirements. The notice-and-comment process for this rulemaking provided the public with sufficient time to evaluate and provide comments on the proposed rule. The EPA is finalizing non-EGU regulatory requirements, as described in Section V and VI.C of the preamble. Comments regarding the EPA's Non-EGU Screening Assessment methodology are further addressed in Chapter 2.2 of this document.

Regarding the commenter's suggestion that the EPA should defer action at Step 1 until the ongoing attainment designation process for the 2015 ozone NAAQS concludes, nothing in the Act mandates this delay and it is contrary to the timing and sequence of actions the Act requires. This is further addressed in Chapter 3.1 of this document. Attainment designation deadlines are specified by section 107 of the Act and are separate from the EPA's obligation to act on interstate transport SIPs and promulgate FIPs, as required under section 110 of the Act. In this rule, the EPA addresses its statutory obligation to issue a FIP for states whose transport SIPs the EPA has disapproved or states for which the EPA has made a Finding of Failure to Submit. As discussed in Section III.B.2 of the preamble, the EPA is required to address interstate transport obligations as expeditiously as practicable. Therefore, the EPA must issue the final rule without delay in accordance with this obligation.

The EPA does not agree with commenter's suggestion that the non-EGU screening assessment is inappropriate for analyzing industrial source emissions at Step 3 of the 4-step interstate transport framework. Responses regarding the appropriateness and technical adequacy of the EPA's final rule approach to include non-EGU sources in the assessment of NO_X emissions reduction potential are included in Sections III and V of the preamble. Responses to questions about economic and technical feasibility for installation of non-EGU control technologies required to meet emissions limits specified by this rule are provided at length in Section V.C of the preamble.

Comment:

Commenter (0798) asserts that in determining what non-EGUs to regulate, the EPA did not correctly follow the "4-step interstate transport framework" used by the EPA in prior rulemakings and approved by the Supreme Court. The commenter remarked that rather than evaluate the upwind emissions that actually contribute to each screened-in state's linked nonattainment or maintenance receptors, the EPA instead just (1) identified industries nationwide that contributed relatively more than other industries, and (2) automatically mandated limits directly on all such industries in each screened-in state, skipping any finding that the industries (let alone specific sources) actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state.

The commenter states that the proposed rule attempts to go well beyond the EPA's authority under the CAA, and the EPA risks legal challenges to any final rule in the same form as the proposed rule that will restrict the EPA's discretion in future rulemakings. The commenter also believes that the EPA's decision to make the proposed rule apply on a unit specific basis directly to facilities means every covered facility will have the ability to challenge the applicability of the proposed rule's limits as applied to that facility, likely jettisoning the uniformity that the EPA purports to seek in the proposed rule and stringing out any rulemaking in constant challenges. For these reasons, the commenter urges the EPA to withdraw the proposed rule in favor of allowing states the opportunity to correct any concerns that the EPA may have with their SIP submittals and in the alternative for the EPA to correct the errors that have been identified with respect to its proposed rule. The commenter requests to be involved in a stakeholder process if the EPA makes significant changes to the proposed rule, and to have adequate to review and comment on any changes.

Response:

The EPA's approach to applying the 4-step interstate transport framework in this rule is described fully in Section III of the preamble. This comment fundamentally misunderstands the analysis used to evaluate upwind emissions. As discussed in the technical memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* specifically analyzed emissions contributions from the industries in the linked upwind states and by assessing the impacts of potential emissions reductions, on a ppb basis, would have at downwind receptors. We note that the 2016v3 modeling used for the final rule generally confirms the identification of the receptors and linkages used in the proposal with only slight adjustments, which are otherwise reflected in the rule (*e.g.*, Minnesota and Wisconsin are not subject to non-EGU requirements in the final rule). Therefore, the identification of impactful industries in the screening assessment prepared at proposal remains appropriate for purposes of its role in the Step 3 analysis. Second, the commenter mistakenly asserts that the specified emissions limits are "automatically mandated" and that the EPA did not assess whether each industry contributed to nonattainment or interference with maintenance at downwind receptors. As explained in the same memo, contributions from individual sources were aggregated on a statewide basis and used to propose a finding that the industries included in the proposed rulemaking significantly contributed emissions to downwind receptors. The EPA finalizes this finding in Section V.B.2 of the preamble. We further respond to comments on the screening assessment in Section 2.2 (Non-EGU Industry Screening Methodology).

The EPA does not agree that this rule "goes beyond" the EPA's authority under the CAA and provides further response to this comment in Section III of the preamble and Section 1 (Legal Comments on the EPA's Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards). Comments regarding future legal challenges to this rule and speculation about court decisions that would restrict the EPA's discretion in future actions are not in scope for this rulemaking. We note that CAA section 307 establishes procedures for judicial review of the final applicability criteria and other regulatory requirements established in this action.

Regarding the commenter's suggestion that the EPA should withdraw the proposed rule and allow states to correct issues with their SIP submittals, we note first that Section VI.D of the preamble provides information for states seeking to submit SIP revisions to replace FIP requirements established by this rule. To this end, the EPA welcomes the opportunity to work with any state interested in submitting an approvable SIP revision. Second, refer to Section III.B.2 of the preamble for additional discussion of the EPA's rationale for issuing FIP requirements "as expeditiously as practical" and in time for the 2023 ozone season, and Sections 1.1 and 2.4 of this document for further discussion of legal authority with respect to these topics.

2.1.1 Step 1

Comment:

The commenter (0323) declares that the proposal is flawed due to the agency's failure to align the timing of the upwind and downwind states' responsibilities as it selected the analytical year for evaluating the good neighbor provisions of the CAA. The commenter further states that the EPA erred at Steps 3 and 4 in assessing control requirements for EGUs and non-EGUs, in redefining the EGU emissions trading program, and in taking significant technical shortcuts to accommodate its self-imposed deadlines.

Response:

The EPA provides a response to comments regarding timing of the upwind states' obligations to reduce significant interstate transport contributions in Section III.B.2 of the preamble. The EPA does not agree that the Agency took technical shortcuts to meet self-imposed deadlines. First, the EPA's obligation to issue the FIP requirements in this rule is required by CAA section 110 and as expeditiously as practical, as explained in the response in Section III.B.2 of the preamble. Characterizing statutory and other legal obligations as a self-imposed or discretionary deadline is not accurate. The assessment of control stringency levels and combined EGU and non-EGU control requirements are described extensively in Section V.B and V.D of the preamble, respectively.

2.1.2 Step 2

Comment:

Commenter (0798) believes because it bears directly on the EPA's authority to regulate facilities and states at all under the good neighbor provision, the EPA must consider any such Comprehensive Air Quality Model with Extensions (CAMx) or Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) modeling whenever it is completed in determining applicability of any final rule. At a minimum this should have been performed for Arkansas and Mississippi which were linked to only a single downwind maintenance receptor, to evaluate what sources and geographic areas could be contributing to these predicted high-ozone days, and whether any impact on the maintenance receptor is truly consistent and persistent enough to be classified as a significant contribution. Commenter (0798) states the EPA failed to perform the modeling needed to assess the significance of state and facility contributions to downwind receptors. Due to the complexity of the subject matter, it is questionable whether this small sample size reasonably reflects consistency of predicted contributions.

Response:

The EPA does not agree that it must establish source- or facility-specific contribution thresholds, which would be inconsistent with the 4-step interstate transport framework applied in this action. We further respond to comments on this topic in Section 2.2.2 (Air Quality Thresholds for Identifying Impactful Industries). The EPA's construction of the 4-step interstate transport framework used in this rule relies on the definition of nonattainment and maintenance receptors at Step 1. The set of nonattainment and maintenance receptors are used to determine linkages at Step 2. In Step 2 of the interstate transport framework, the EPA uses an air quality screening threshold of 1 percent of the 2015 ozone NAAQS to identify upwind states that contribute to downwind ozone concentrations to "link" them to these to downwind nonattainment and maintenance receptors. The screening threshold is applied uniformly across the full modeling domain. The consistent application of the uniform screening threshold using a standard contribution metric that is applied consistently to all states is the predominant evidence used to determine linkages at Step 2. These states move on to further analysis at Step 3, where the EPA analyzes whether NO_X emissions from the upwind linked states constitute significant contribution that must be eliminated under CAA section 110(a)(2)(D)(i) requirements.

The nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique that was used to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the corresponding projected ozone design values (DVs) in 2023 and 2026 at air quality monitoring sites is described comprehensively in Section IV.E.1 of the preamble to this rule and in 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 Air Quality Modeling Final Rule TSD. Further responses to comments regarding the technical adequacy of air quality modeling used in this rule are provided in Section 3 (EPA's Analysis of Downwind Air Quality Problems and Contributions from Upwind States).

Comment:

Commenter (0518) suggests that the EPA conduct a new Step 2 analysis based on an appropriate ozone source apportionment tool and applying the 1 ppb threshold, consistent with peer-reviewed statistical analysis and the EPA's own guidance.

Response:

The EPA responds to comments regarding the use of an alternative 1 ppb threshold in Section IV.E of the preamble to this rule.

Comment:

Commenter (0289) declares that the EPA could achieve the intended outcome with a more rigorous Step 2 approach that apportions contributions more granularly. The commenter contends that if the EPA wanted to perform a more equitable approach to good neighbor provisions, it would not base linkages on total upwind state contributions but would tag individual facilities to determine the individual facility contributions to downwind state problem receptors. The commenter claims that doing this would make for far more equitable solutions to address the ozone problems in downwind states at substantially lower costs because sources that have no impact on the downwind problem receptor would not be affected. While the commenter acknowledges that this may be somewhat resource intensive, the commenter would support the EPA to direct resources towards this effort so that at Step 3, control requirements can be focused on the facilities contributing to the downwind problems.

Response:

The EPA agrees with the commenter that conducting source apportionment modeling to determine transport contributions from individual facilities would be significantly more resource intensive than the ozone source apportionment modeling used to support this rule, as described in Section IV.D of the preamble. However, the EPA does not agree that conducting air quality modeling based on upwind contributions from individual facilities to determine linkages to downwind receptors would yield "more equitable solutions" to addressing the ozone air quality problem in these areas "at substantially lower costs." The cost of controls is explicitly evaluated at Step 3 of the 4-step interstate transport framework as part of the multifactor analysis for determining significant contribution. The commenter does not provide any further information for the EPA to determine that the suggested method of performing facility-specific contribution modeling would yield a more cost-effective strategy for eliminating significant contribution than the approach the EPA applies.

2.1.3 Step 3

Comment:

Commenter (0327, 0912L) concurs that the proposed rule "appears to be more about meeting the current Administration's announced goals of eliminating fossil fuel power plants than addressing significant contributions to serious environmental risks." At least one commenter (0327) asserts that the proposed rule ignores the fact that ozone levels continue to drop and power plants are playing an ever-smaller role determining those levels relative to mobile and other sources.

Response:

The commenter does not provide information to support their claim that the proposed rule "appears to be more about meeting the current Administration's announced goals of eliminating fossil fuel power plants than addressing significant contributions to serious environmental risks." Fossil fuel power plants are covered by this rule because they provide cost-effective opportunities to reduce upwind ozone precursor emissions that are significantly contributing to downwind nonattainment or interference with maintenance of the NAAQS in downwind areas. Our determinations regarding which emissions reductions are needed to eliminate significant contribution are set forth in Section V of the preamble.

Comment:

Commenter (0359) states that the EPA did not provide sufficient justification for its conclusion that NO_X emissions from non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS, nor 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. According to the commenter, the EPA fails to demonstrate a correlation between the proposed emissions rate limits and the costs for the selected control technologies and also fails to provide a justification for the proposed emissions rates. The commenter adds that non-EGU NO_X emissions sources include shorter stack heights and lower gas volumes, and as such, emissions from these stacks are significantly less likely to measurably impact downwind areas and monitors.

Response:

As discussed in Section V.D of the preamble, the non-EGU emissions control strategies in the final rule will deliver measurable and meaningful improvements in air quality at downwind receptors. Further response to comments on the basis for the inclusion of the non-EGU industries in this rule is in Section 2.2 (Non-EGU Industry Screening Methodology).

2.1.4 Step 4

Comment:

Commenter (0554) states that the EPA should also acknowledge state authority to re-evaluate Steps 3 and 4 of the EPA's 4-step interstate transport framework methodology by identifying and implementing the measures needed to eliminate what the EPA has defined to be a significant contribution to downwind receptors, rather than requiring states to demonstrate that their measures, along with federal measures, will achieve reductions commensurate with installation of SCR on coal-fired EGUs by the 2026 ozone season. The commenter believes states are uniquely positioned to identify the right mix of requirements for the unique emissions sources in their jurisdictions and to determine how best to align those requirements with other regulatory efforts that target some of the same units and pollutants, like regional haze. As long as a state can submit modeling to show that emissions reductions from sources in its state will eliminate the downwind impact that the EPA has defined as significant, its SIP should satisfy the requirements of the good neighbor provision and the EPA must approve it.

Response:

Comments regarding the EPA's determination of whether transport SIPs submitted for the 2015 ozone NAAQS satisfy the requirements of the good neighbor provision are outside the scope of this rulemaking. The EPA agrees that states have a primary responsibility to provide SIP required by CAA section 110. However, the Agency has a statutory duty to implement a FIP in those instances where a state has not submitted an approvable SIP or where the Agency has made a finding of failure to submit.

Section VI.D of the preamble discusses ways states may replace the FIP requirements promulgated in this rule with a SIP.

2.1.5 Other 4-Step Interstate Transport Framework Comments

Comment:

Commenter (0328) remarks that allowing non-EGU owners and operators the option to buy and retire allowances for excess emissions through an allowance surrender requirement during the control period would address the issue of regulating NO_X emissions generated outside the ozone season. The commenter suggests that if the EPA needs to consider the limits as backstops, it should require a 3:1 surrender, similar to coal fired EGUs, for excess emissions. According to the commenter, this would provide incentive to control the units during the ozone season. The commenter adds that this non-EGU allowance surrender approach would be more consistent with the provision of past trading programs and treating the proposed non-EGU limits as backstops or requiring allowance surrender for excess emissions would give non-EGUs with existing controls and limits in place some flexibility in meeting the proposed FIP obligations without causing compliance issues in many states, including Pennsylvania.

Response:

The EPA requested comment on options for including non-EGU industry sources in an ozone season, allowance-based trading program in the proposed rulemaking. We evaluated a number of comments on this topic and determined that it is not appropriate to include the industrial sources covered by this rule in a trading program, for reasons explained in Section VI.C of the preamble. We do not agree with the commenter's implicit claim that allowing non-EGU industry sources to purchase excess allowances via the suggested 3:1 surrender mechanism is necessary to provide an incentive for continuous operation of EGU NO_X controls.

The FIP requirements established for non-EGU sources in this rule reflect widely available control technologies and standards based on other federal and state regulatory programs. The EPA does not agree that the FIP requirements will cause compliance issues for regulated sources in covered states.

Comment:

Commenter (0352) states that in a supplemental rule, the EPA should rely on monitored data over modeled data when evaluating which areas need transport obligations resolved. The commenter specifically mentioned "when issuing a… 2015 NAAQS transport rule, the EPA should give priority to monitored data over modeled data when evaluating which areas need transport obligations resolved," and the commenter reiterates this concern because a failure to rely on monitored data is even more evident with this rulemaking. According to the commenter, infrastructure SIPs for the 2015 NAAQS were due in 2018, and states were required to achieve emissions reductions by the relevant CAA mandated attainment deadlines (2020 for marginal nonattainment areas). The commenter relates that in 2022, the EPA still relies on future-year projections of DVs, in this case to 2023, years after upwind states were required to meet their obligations. Furthermore, the commenter relates that the 2023 projections are representative of DVs, thereby illustrating averages of the 4 highest 8-hr ozone values in 2021, 2022, and 2023. The commenter states that all recorded Washington D.C. (*i.e.*, District) ozone data from nearly five months in 2022 have overtaken DV projections. According to the commenter, to attain the EPA modeled levels, which determines whether a monitor is a receptor, the 4th highest 2023 8-hr Ozone values need to be 33 percent lower than the 4th highest ozone values from 2020. The commenter suggests that attainment is not possible because stricter Coronavirus disease 2019 (COVID-19) protocols severely suppressed these values. The commenter adds that the EPA's analysis also assumes ozone will not increase during the summer of 2022, which is unlikely given that the three hottest months are yet to occur. The commenter asserts that receptor status must be based on whether a nonattainment area failed to attain the NAAQS. The commenter states that this change is especially problematic for the District since the EPA's own modeling shows that 95 percent or more of our ozone pollution comes from outside of our borders. The commenter asserts that the EPA should require upwind states to act sooner, rather than pushing reductions from upwind states that contribute to and exacerbate the District's current poor air quality into the future.

Response:

The EPA agrees with the commenter regarding the need to finalize the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards to implement the rule by the 2023 ozone season. The timing of this final rule is further discussed in Section III.B.2 of the preamble. The EPA has addressed the commenter's concern regarding taking fuller account of more recent monitored ozone levels in identifying nonattainment and maintenance receptors. See Section IV.D of the preamble. We note that this methodology does not identify Washington, DC as being a "violating monitor" receptor area in 2023. Nonetheless, the Washington, DC area will experience air quality benefits through the emissions reductions being implemented in this action.

Comment:

Commenter (0436) believes that the inclusion of three western states in the CSAPR trading program, which was originally designed and intended for Eastern states only, is inappropriate. The commenter believes that between the significant limitations in the inventory and modeling analysis this action is built on, the substantial regionally specific challenges present in the western US, and the fact that Utah co-developed with the EPA Region 8 a fully approvable SIP, Utah should not be included in any final rulemaking associated with this FIP.

Response:

The EPA responds to the comment regarding the technical adequacy of the emissions inventory and modeling analysis for application to states in the western US in Section 3 of this document (EPA's Analysis of Downwind Air Quality Problems and Contributions from Upwind States). We further respond to comments on treatment of western states in Section

2.4.4 (Authority with Respect to Western States.

Comment:

Commenter (0505) remarks that **s**takeholders cannot adequately assess if the proposed reductions are necessary since the EPA's definition of "significant contribution to nonattainment or interference to maintenance" is unclear and appears to conflate the ability to mitigate contributions with whether the contribution is itself significant. The commenter urges the EPA to first provide a definition of what a "significant contribution to nonattainment or interference to maintenance" is and methodology that clearly establishes that modeled contributions from linked upwind states significantly contribute to nonattainment at downwind monitors prior to evaluating the emissions reductions potential of a linked state. The commenter also urges the EPA to reevaluate its proposed FIP and the proposed Texas transport SIP disapproval in light of the update. According to the commenter, because the EPA did not identify significant contributions before determining if emissions reductions are needed, it failed to provide a rational justification for why areas are significantly linked to downwind receptors; nor has the EPA provided a rational justification for why the required reductions are not overcontrol. [see EME Homer City, 572 US 489, 523-524 (2014)], stating that a state may bring a particularized as-applied challenge if it believes the EPA is requiring reductions "beyond the point necessary to bring all downwind States into attainment."

Response:

This rule uses a multi-factor analysis at Step 3 of the 4-step interstate transport framework to determine significant contribution to nonattainment or maintenance of the NAAQS in downwind states. As explained in Section V.A of the preamble, the multi-factor test (1) identifies levels of uniform NO_X control stringency; (2) evaluates potential NO_X emissions reductions associated with each identified level of uniform control stringency; (3) assesses air quality improvements at downwind receptors for each level of uniform control stringency; and (4) selects 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. This is the same basic approach to determining which amount of contribution is "significant" at Step 3 that the Supreme Court upheld in *EME Homer City*.

The comment regarding the EPA's proposed disapproval of Texas' 2015 ozone transport SIP is not in scope for this rulemaking.

The EPA does not agree with the commenter's claim that the required reductions constitute over-control. The EPA analyzes overcontrol in Section V.D.4 of the preamble.

Comment:

Commenter (0512) states that the proposed "enhancements" to the interstate trading program will hamper the function of the program and are unnecessary to achieve compliance with the Act. The commenter relates that these enhancements include imposing a "backstop" daily emissions rate of 0.14 lb/MMBtu for coal steam units greater than or equal to 100 megawatt (MW), and, starting in August 2024 before the 2025 ozone season, "dynamic budgeting" that will continuously ratchet down emissions budgets, effectively mandating greater emissions reductions over time. The commenter believes these enhancements will result in overcontrol by increasing the stringency of the program over time. According to the commenter, in addition to exceeding the EPA's authority under the Act, these new measures jeopardize the functionality of the good neighbor trading program and the support it provides for asset transitions. According to the commenter, without the flexibility provided by a cost-effective emissions trading program, EGUs will be forced to choose between accelerating retirements or prolonging the life of fossil units through the installation of costly controls. According to the commenter, the EPA justifies the imposition of these new constraints based on its observation of "instances of units idling their emissions controls in the latter years" of prior good neighbor FIPs. The commenter disagrees with the EPA's proposed solution to this problem and states that the EPA should exercise its authorities under the Act and undertake a state-specific rulemaking if and when a problem actually occurs rather than acting in anticipation of potential later problems. The commenter urges the EPA not to include the enhancements in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.

Response:

The EPA provides a response to comments regarding the impacts of the daily backstop emissions rate and dynamic budgeting on the overall function of the CSAPR Group 3 Trading Program in Section VI.B of the preamble and Section 5.2 of this document.

The EPA responds to the commenter's claim that dynamic budgeting and daily backstop emissions rates exceed the EPA's authority under the Act in Section III.B.1 of the preamble. The effect of the trading program enhancements on supporting asset transitions and overall electric grid reliability is discussed in Section VI.B.1.d of the preamble. Finally, the EPA notes that the statement in the proposed rule of "instances of units idling emissions controls" under previous CSAPR programs reflects the Agency's observation of unit behavior in the fleet, as verified through emissions reporting mechanisms. This statement alone clearly does not constitute the full breadth of the Agency's rationale for including such enhancements in the final rule. The EPA is finalizing the trading program enhancements on the basis of the complete record for this rulemaking.

Comment:

Commenter (0519) asserts that the EPA's analysis for Oklahoma is unreasonable at each Step and therefore, Oklahoma should not be included in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards. First, according to the commenter, the EPA concludes in its proposed rule that Oklahoma has not submitted an approvable SIP, even though the EPA has not completed the required rulemaking process to finalize such a determination. Second, the commenter states that the EPA unreasonably rejects a 1 ppb linkage threshold despite previous guidance indicating that such a threshold would be appropriate. Considering these points, the commenter concludes that the EPA has improperly included Oklahoma in its proposed rule.

Response:

The EPA responds to comments regarding timing of the FIP and SIP actions with respect to interstate transport obligations for the 2015 ozone NAAQS in Section III.B.2 of the preamble, and these topics are further addressed in Section 1 and 2.4 of this document.

In Section IV.B.2 of the preamble to the proposed rulemaking, "FIP Authority for Each State Covered By the Proposed Rule," The EPA noted that the Agency proposed to disapprove Oklahoma's good neighbor SIP submission on February 22, 2022, at 87 FR 9798. In the "Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668, 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 Proposed Rule TSD," hereinafter referred to as Status of 2015 NAAQS CAA section 110(a)(2)(D)(i)(1) SIP Submissions Proposed Rule TSD, the EPA listed the proposed disapproval of Oklahoma's October 25, 2018 good neighbor SIP submission.

Section IV.B.2 of the proposed rule further noted that the EPA would not finalize FIP requirements for any states, including Oklahoma, in the proposed rule "unless and until the EPA formally finalizes disapprovals of their SIP submittals." The EPA has since taken final action on January 31, 2023, to disapprove Oklahoma's transport SIP submission for the 2015 ozone NAAQS at 88 FR 9336. As discussed in Section II.C of the preamble and the Status of 2015 NAAQS CAA section 110(a)(2)(D)(i)(1) SIP Submissions Final Rule TSD, the EPA has legal authority under CAA section 110(c) to promulgate a FIP for Oklahoma in this final rule.

Comments regarding the Step 2 contribution threshold are addressed in Section IV.F.2 of the preamble.

Comment:

Commenter (0528) states that the EPA failed to account for the electric grid reliability issues that would immediately result from the FIP, including substantial EGU retirements. The commenter further argues that the EPA acted beyond its authority by assessing generation shifting as a control technology and proposing restrictions that could fundamentally alter the make-up of the electric generation industry.

Response:

The EPA provides a response to the comment regarding electric grid reliability and EGU unit retirements in Section VI.B.1.d of the preamble.

Generation shifting is addressed in Section V.B.1.f of the preamble.

Comment:

Commenter (0553) states the 40 CFR part 97 NO_X Budget Trading Program provides the model for previous ozone interstate transport regulations and has demonstrated that an allowance-based system can provide an effective means for states to achieve significant emissions reductions and the full remedy to meet the CAA's good neighbor provisions. The EPA has recognized this success and has taken care in the past to avoid unnecessary restrictions that impede the market and interfere with the ability to assure compliance through an effective trading program. In fact, the EPA has previously analyzed emissions during the

2017 ozone season under the CSAPR Update rule and found that the seasonal trading program not only provided an overall reduction in emissions but was also effective at reducing short-term emissions, as evidenced by emissions rates observed across the region on days with high generation demand. That finding is consistent with an effective trading program, since high demand for power also means high demand for allowances which incentivizes operators to optimize control of emissions and reduce allowance consumption.

Response:

Response to comments regarding the basis for the trading program enhancements is addressed in Section VI.B of the preamble and in Section 5.2 (Regulatory Requirements for EGUs).

Comment:

Commenter (0324) urges the EPA to develop a mechanism to reevaluate this rule based on future actual conditions. As an enhancement to its previous CSAPR rules, the EPA proposes to annually update NO_X budgets starting in 2025 to account for new retirements, new units, and changes in operation. The intention of this change is to help ensure that the rule will continue to meet its statutory objectives, even if unanticipated changes in source emissions occur in the future. The commenter asserts that, given the minimal air quality benefits the EPA expects this rule to provide Wisconsin's non-attaining monitors, the EPA should develop a similar mechanism to reevaluate the adequacy of this rule after the 2023 and 2026 ozone seasons to ensure this rule actually ends up constituting the 'full remedy' required by the CAA. As an example, the commenter indicates that if 2023 DVs end up being higher than those predicted by the EPA in this proposal, the EPA would need to take additional action to adequately address upwind state contributions. The commenter believes that such an assessment would require limited additional work for the EPA, since updated ozone modeling is being continually conducted and the EPA is already committing to a regular reevaluation of NO_X budgets.

Response:

The EPA does not agree that the adequacy of the rule must be continually re-assessed. We note that the dynamic budgets in the Group 3 trading program will be implemented through ministerial action and are not based on any policy reevaluation. 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).

2.2 Non-EGU Industry Screening Methodology

2.2.1 General Criticism of Non-EGU Screening Assessment Methodology

Comments:

Commenter (0518) avers that the EPA should reevaluate its non-EGU screening assessment at Step 3. According to the commenter, at Step 3, the EPA uses a multi-factor analytical framework for non-EGUs that relies on outdated and inaccurate information, applies approaches that are inconsistent with past agency policy, and fails to reasonably identify non-EGU significant contribution to downwind receptors or highly cost-effective controls to address such contribution. In addition, the commenter says that this multi-factor test utilizes several arbitrary, unjustified, and outcome-determinative elements that invalidate the EPA's basis for the screening assessment and Step 3 analysis for non-EGUs. The commenter urges the EPA to collect the necessary information, conduct the proper analysis, and reevaluate its non-EGU screening assessment for public input before proceeding with this rulemaking. According to the commenter, the EPA's non-EGU screening assessment (1) warrants additional information and analysis; (2) erred in relying on the Air Quality Assessment Tool; (3) inappropriately groups sources by NAICS code; (3) arbitrarily lowered the emissions threshold of sources screened; (4) utilizes an unjustifiably new level of emissions deemed significant; (5) applies an exorbitantly high cost threshold; and (6) fails to consider feasible controls to be installed in the time evaluated. The commenter urges the EPA to reconsider and modify its Step 3 screening assessment for non-EGUs.

Commenter (0308) states that the EPA did not provide an explanation for why select industries were singled out for proposed regulation. The commenter also states that the applicability criteria between industrial categories needs to be consistent and concise. The commenter notes that it is particularly confusing as to whether the NAICS Codes are used to determine applicability. Specifically, according to the commenter, it is unclear whether an otherwise applicable emissions unit located at a facility whose primary NAICS Code is not identified in the rule is subject to the FIP.

Commenter (0798) asserts that the analyses included in the record cannot support the source-specific and site-specific impact findings required by the CAA. According to the commenter, the EPA has not adequately demonstrated that the individual or category of sources it proposes to regulate under the proposed FIP cause or interfere with ozone attainment or maintenance in downwind states, but instead uses inaccurate assumptions in its analysis and modeling rendering the entire FIP fatally flawed. The commenter relates that the 4-step interstate transport framework as applied in the proposed rule identifies no sources or emissions activities in one state that significantly contribute to downwind air quality problems in another state, and even for states that are contributing to nonattainment or interfering with maintenance, the EPA has established no data to support which non-EGU emissions sources within the state are "potentially controllable," would "have the greatest ppb impact on downwind air quality" or could "make meaningful air quality improvements at the downwind receptors at a marginal cost threshold" as the EPA's own interpretation of the CAA dictates. The commenter asserts that without this information, the EPA's FIP is arbitrary and capricious, citing *State Farm*, 463 U.S. at 43. The commenter contends that there has been no attempt to gather or model the source-specific data needed to determine what sources, if any, should be subject to regulation to address interstate transport of NOx. For the proposed rule, the EPA has conducted a non-EGU "Screening Assessment" to identify costs and controls, but the EPA itself acknowledges that 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." While EPA points to the screening assessment it used in CSAPR, and which was affirmed by the Supreme Court in *EPA v. EME Homer City Generation, LP*, 572 U.S. 489 (2014), there the EPA was allocating state-level emissions budgets and was based on "complex modeling to establish the combined effect the upwind reductions projected at each cost threshold would have on air quality in downwind States." [*Id.* at 1596]. The commenter avers that the EPA's assessment, while starting with state-specific modeling to identify "linked" states, then proceeds to ignore any state-specific distinctions in evaluating the emissions sources that should be subject to regulation. The commenter asserts that the EPA cannot impose source and unit-specific emissions requirements without first confirming that its screening assumptions hold up when applied to the actual states, sources, and emissions units that will be subject to regulation. Otherwise, the commenter declares that the EPA has "entirely failed to consider an important aspect of the problem" and "offered an explanation for its decision that runs counter to the evidence before the agency." [see *State Farm*, 463 U.S. at 43.]

Commenter (0764) states that the EPA did not determine or document the necessity and relative significance of the proposed emissions reductions. The commenter claims that rather than completing an analysis of the emissions reductions that are necessary for each state to mitigate its contribution to any linked downwind receptor(s), the EPA arbitrarily equated contributing emissions with (ostensibly) cost-effective emissions reductions, regardless of the contribution by the emissions to a receptor. The commenter declares that to apply the same non-EGU emissions requirements across all affected states regardless of the relative significance to a receptor is nonsensical, inconsistent with the EPA's prior approach to interstate transport, fails to demonstrate that the EPA is avoiding overcontrol, and is arbitrary and capricious.

Commenter (0382) states that the proposed FIP arbitrarily regulates seven industries and imposes attainment requirements that many cannot achieve in a cost-effective manner. The commenter asserts that the EPA offers no justifiable reason for the extension of the Transport Rule to these seven industries. The commenter adds that an analysis conducted by the Midwest Ozone Group shows that, in at least two geographic areas, certain vehicles contribute around three times as many NOx emissions as all non-EGU and that NOx emissions from these vehicles could be reduced by 90 percent for less than 2 percent added cost. The commenter notes that the proposed FIP does not assess or even mention such vehicles.

The commenter (0514) reports that the proposed rule and its supporting documents do not include any analyses that would be required to subject SAFs or silicon metal producers to regulations under the good neighbor provision, including a demonstration of significant contribution to downwind maintenance or nonattainment by the industry or a facility, demonstration that a proposed emissions limit is technically feasible and cost effective, and demonstration that reductions could be required without resulting in overcontrol. The commenter also states that the screening assessment only compared relative contributions of different industries and never explained why the industries selected for regulation had impacts that were significant with respect to downwind receptors, as opposed to merely being relatively more significant than other clearly insignificant industrial activities. According to the commenter, if the EPA continues to propose regulation of any non-EGU sources in Mississippi, it should adhere to the statutory text by only regulating industries within a particular state which significantly contribute to that state's linked receptors. The commenter adds that if the EPA wishes to reach beyond industry level regulations to instead require source specific reductions, then it must demonstrate that the source it seeks to regulate poses a "significant contribution" to receptor's nonattainment or maintenance in downwind states.

Commenter (0362) believes the EPA has overstated the potential ozone season reductions available from the non-EGU sector. According to the commenter, if more reasonable assumptions about the potential NOx reductions available from non-EGU boilers had been considered, the EPA may have opted not to include non-EGU emissions in its analysis and emissions reduction requirements. The commenter states that the relative downwind change that can be attributed to non-EGU individual sources or sources in a state does not constitute a significant contribution. The commenter remarks that non-EGU sources typically have shorter stacks, fewer operating hours, and lower emissions, so their impact on nonattainment areas (receptors) that are located hundreds of miles downwind are negligible. The commenter claims that imposing additional reductions from non-EGU units creates a financial burden on the domestic manufacturing sector with little to no tangible environmental benefit to the nonattainment areas that the EPA seeks to assist through this proposed rule.

Commenters (0284, 0320, 0437, 0557) state the 2017 NEI data set is of questionable quality. The commenters provide examples: several units are not labeled with the correct NAICS or SCC, some units do not have a capacity associated with them, the air emissions control information is incomplete, some states report allowable and not actual emissions, etc. As a result, the commenters find it difficult to determine how many boilers are at a particular facility if a boiler fires multiple fuels and has one line per fuel or if multiple boilers exhaust to one stack. The EPA also did not verify that the NEI data were representative of the currently operating boiler types, sizes, and emissions. Even if the data set were accurate, it does not include each boiler's actual lb/MMBtu NOx emissions rate, so there is no way the EPA can accurately identify what boilers may or may not be able to comply with the proposed emissions limits. The Agency's analysis is inherently flawed because it did not ask states or facilities to verify existing control information, did not realistically predict impacts of applying emissions controls to meet the proposed limits, and did not verify whether potential reduction opportunities identified from the CoST would result in real reductions.

Commenters (0320, 0359) state that the EPA underestimates the cost of SCR and has not performed air dispersion modeling to determine if NOx controls on industrial boilers will actually have an impact on downwind monitors. Subject boilers that are not already controlled will likely need to apply SCR to achieve the required emissions rate.

The commenter (0359) states that while the proposed rule repeatedly re-directs the reader to the Non-EGU Screening Assessment memo, the Non-EGU Screening Assessment, and corresponding "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 Proposed Non-EGU Sectors TSD, it fails to make its case as to why non-EGUs are found to be impactful in Step 3. According to the commenter, if the EPA cannot adequately demonstrate that upwind emissions constitute "significant" contributions considering cost- and air quality-based factors under Step 3 of the 4-step interstate transport framework, it cannot proceed to proposing controls to implement emissions reductions through enforceable measures without dismissing its own methodology.

Commenter (0504) remarks that the EPA's screening analysis improperly concludes that steel sector facilities contribute significantly to downwind nonattainment or interfere with maintenance. According to the commenter, in its review of the EPA's modeling data, incorrect information was used. The commenter notes that it is not aware of one source identified as a boiler at the Nucor facility or of another source identified as a blast furnace, which would not be part of an EAF. The commenter also says that it could not find the source of any of the modeling parameters in the record and cannot confirm that the source characteristics are accurately depicted in the EPA's model.

Commenter (0760) relates that just one year ago, the EPA concluded that there was no reason to regulate non-EGUs under the CSAPR Update rule. The commenter states that while that assessment dealt with the 2008 ozone standard rather than the 2015 ozone NAAQS, the same conclusions cannot be completely reversed in the space of one year without further analysis.

Response:

The EPA disagrees with the commenters that the analytical approach used to identify potentially impactful non-EGU industries and emissions sources for further analysis of emissions-control opportunities is unreliable. The primary purpose of the EPA's *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (hereinafter "Screening Assessment") was to identify potentially impactful industries and emissions unit types for further evaluation. The Screening Assessment memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150. In the Screening Assessment memorandum we presented an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026. We did not propose emissions limits for non-EGU industry sources based only on the Screening Assessment, and the emissions limits that we are finalizing reflect further adjustments taking into account refinements in our understanding of what NOx emissions controls are reasonable and cost-effective for the identified industries and emissions unit types. See Sections V.B.2, V.C.2, and VI.C of the preamble.

Note that the Screening Assessment memorandum included the following language at the beginning of Section V:

> *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.*

The memorandum titled *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" describes the proposed non-EGU applicability criteria and the relationship between those criteria and the Screening Assessment. This memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0191. Note that this memorandum included the following language:

> *The Screening Assessment was not intended to identify the specific emissions units subject to the proposed emissions standards under the proposed applicability criteria described above. Rather, the Screening Assessment 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.*

As stated, the primary purpose of the Screening Assessment was to identify potentially impactful industries and emissions unit types for further evaluation. While the EPA has confidence in its identification of impactful industries (identified in Step 1 of the analytical framework presented in the Screening Assessment), 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 or in the final rule. Further, while the EPA noted that its analysis was not intended to take the place of detailed engineering analyses for emissions controls on individual emissions units identified through the impactful industries assessment, that was not intended as a statement that the Screening Assessment did not serve as reliable method at the first step of our evaluation of non-EGU sources to identify impactful industries, emissions unit types, and potential emissions control opportunities for further analysis.

Thus, to further evaluate the potentially impactful industries and emissions unit types and establish the proposed emissions limits, the EPA reviewed a wide variety of information to further refine its understanding, once the Screening Assessment had been used to identify the most likely sources of potentially impactful, cost-effective emissions reductions for the nine industries identified. In conducting this refined analysis, the EPA reviewed Reasonably Available Control Technology (RACT) rules, NSPS rules, National Emissions Standards for Hazardous Air Pollutants (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. This analysis was explained in the Proposed Non-EGU Sectors TSD, available in the docket for this rule here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145. For the final rule, this review has been updated and incorporates new information, including comments received on the proposal, as detailed in 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, also available in the docket for this action.

Once the EPA, in consideration of comments on proposal and additional updated information, had developed its final applicability criteria, emissions limits, and associated compliance requirements, we updated the analysis of the emissions reductions that could result, both during the ozone season and annually (though annual control operation is not required by the rule), and associated compliance costs. We estimated representative cost-per-ton values for each industry/emissions-control type, similar to the representative cost-per-ton values used for EGUs. The updated emissions reductions estimates informed our final assessment of the air quality effects of these emissions limits, as discussed in Section V.D of the preamble. This updated analysis is presented in the technical 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* (hereinafter "Final Rule Technical Memorandum"), also available in the docket. That memorandum contains citations to the underlying workbooks and other data files, which are also available in the docket.

Commenters have not established why there is anything unreasonable or unlawful in the way in which the EPA proceeded through this analysis to arrive at its final emissions-control requirements for non-EGUs, nor have they established why the Screening Assessment was not an appropriate analytical method, at the early stage of that process, to identify potentially impactful industries and emissions control opportunities for further evaluation. There is nothing inconsistent in this approach with how we have approached assessing emissions control opportunities in prior ozone transport rulemakings, and in particular, the analysis of emissions control opportunities on an industry-wide basis. For example, in CSAPR, we focused on a single industry, the power sector (or EGUs), because we found that in general, across this industry, there were highly cost-effective emissions control opportunities compared to other industries (based on our assessment at that time). *See* 76 FR at 48249. Similarly, in the NO_X SIP Call, we also focused on assessing emissions-control opportunities by industry (using NAICS-code industry classifications as we do in this action), while recognizing that boilers are a unit type that could have cost-effective emissions reductions across multiple industries (as we again recognize in this action). *See* 63 FR at 57399. The EPA explained in the NO_X SIP Call that this approach "assure[d] equity among the various source categories and the industries they represent," *id*. Similarly, here the Screening Assessment focused on identifying potentially cost-effective emissions control technologies or measures at the industry level. *See* Screening Assessment at 2.

One commenter asserts that the Screening Assessment for non-EGUs was nothing like the "screening assessment" performed in CSAPR using complex air quality modeling that ultimately resulted in CSAPR's final EGU emissions budgets. It is unclear what the commenter is referring to, and this statement appears to confuse a number of different steps in the EPA's analytical process both here and in CSAPR. In CSAPR, as in all EPA regional ozone transport rules, the EPA established emissions control requirements of a uniform nature across the entire identified industry (*e.g.*, EGUs) and across all upwind states. The Agency showed how that approach would result in meaningful improvement in air quality at downwind receptors, *e.g.,* 76 FR at 48258, but the Agency did not purport (nor was it necessary) to make a demonstration as to how the precise emissions reductions from each specific source covered by the trading program had a specific ppb-related effect at a particular receptor that thus constituted that source's "significant contribution." The Supreme Court upheld the Agency's approach in *EME Homer City* as an efficient and equitable approach to the allocation of upwind emissions reduction responsibility without demanding the level of analysis the commenter here claims were required or conducted. Similarly, the Screening Assessment here was one step of a process toward identifying reasonable, feasible, cost-effective emissions reduction opportunities for ozone season NOx from non-EGU sources in linked upwind states. This process ultimately resulted in the emissions limits and associated requirements being finalized in this action. As with CSAPR's approach to allocation of emissions-reduction obligations for EGUs, we demonstrate in this action that the approach of establishing uniform, cost-effective, emissions control requirements, by industry (or, in the case of boilers, by impactful unit-type) is an approach to defining significant contribution that results in meaningful air quality improvement at downwind ozone nonattainment and maintenance receptors. *See* Section V.D.2 and V.D.3 of the preamble (showing AQAT-derived, estimated non-EGU associated air quality improvements and combined EGU and non-EGU associated air quality improvements). *See also* Section VIII of the preamble (discussing and summarizing CAMx-derived air quality projections reflecting the "final rule" emissions control requirements).

Regarding the claim that the EPA is reversing course from the position it took regarding non-EGU emissions in the Revised CSAPR Update, the Agency disagrees that there is anything unexplained or inconsistent in our evaluation here compared to that rule. In the Revised CSAPR Update, the EPA evaluated non-EGU emissions reduction opportunities for the less protective 2008 ozone NAAQS. To summarize the conclusions from the Revised CSAPR Update analysis, we found that the earliest non-EGU emissions reduction opportunities could be available was in 2023. We analyzed emissions control opportunities at non-EGUs that were of a commensurate cost per ton with the EGU emissions control strategy in 2023 in that rule, which was $1,800/ton. At this level of stringency, in that year, we found that non-EGU emissions reductions would result in roughly a 0.03 ppb improvement at the single Connecticut receptor projected to remain. We noted this was an order of magnitude less air quality improvement than what was projected to be achieved through the EGU emissions control strategy, which would achieve a 0.28 ppb improvement at that receptor. We concluded that it was not necessary to require these emissions reductions to eliminate significant contribution for the 2008 ozone NAAQS. *See* 86 FR 23054, 23110 (April 30, 2021).

By contrast, in this rule for the more protective 2015 ozone NAAQS, we find numerous downwind receptors that will persist through 2026, the year by which we find non-EGU emissions controls could generally be implemented. In our analysis, we find that emissions control opportunities from the identified non-EGU industries would result in emissions reductions of approximately 44,616 tons of ozone season NOx. *See* Table V.C.2-1 in the preamble. By comparison, the EGU emissions control strategy would, by 2026, achieve a 74,973-ton reduction in ozone season NOx. *See* Table V.C.1-2. The non-EGU strategy would achieve, on average, a 0.19 ppb improvement in air quality at the identified receptors in 2026, and a 2.82 ppb improvement in air quality in total across all receptors. This represents roughly one-third of the air quality improvement that would be achieved in 2026 in the final rule (*i.e.*, roughly one half of the improvement achieved from EGUs). While still less than the emissions reductions and air quality improvements achieved through the EGU emissions control strategy, these emissions reductions are impactful and meaningful in the context of assisting downwind states in resolving nonattainment and maintenance problems for the 2015 ozone NAAQS. Further, we note that the weighted average cost of non-EGU emissions reductions in this rule is estimated to be $5,339/ton, roughly half the representative average cost/ton stringency for EGUs, which is $11,000/ton. *See* Section V.D.2 of the preamble.

Thus, in terms of estimated total emissions reductions, cost/ton, and air quality impacts, the emissions limits established for non-EGUs through this action are meaningful and compare favorably with the emissions control strategy for EGUs. The same factors and considerations that the EPA applied in concluding that non-EGU emissions controls were not necessary to eliminate significant contribution in the Revised CSAPR Update all tend to support the basis for the EPA's conclusion to require such controls to eliminate significant contribution in this action.

The EPA further responds to specific comments regarding the EPA's Screening Assessment and the basis for regulation of non-EGU sources in the remainder of this section.

2.2.2 Air Quality Thresholds for Identifying Impactful Industries

Comment:

Commenter (0798) avers that the EPA has identified no legal basis for imposing emissions unit specific limits on any of the individual non-EGU emissions units the proposed rule purports to regulate. First, the EPA does not define any threshold to evaluate whether a given source's contribution constitutes a significant contribution to downwind linked receptors for purposes of the good neighbor provision. Instead, the EPA sweeps in states based on a statewide significance threshold of 0.7 ppb, identifies industries that on a nationwide basis contribute to downwind nonattainment or maintenance receptors using a 0.01 ppb significance threshold, then skips to applying the proposed rule's limits to all facilities in all such industries in all covered states without any evaluation of the statutory mandate to consider whether the specific covered "source or other type of emissions activity" will "contribute significantly to nonattainment." Failure to even set a threshold to evaluate source-level contribution significance constitutes a failure to attempt the evaluation required under the statute if the EPA wishes to set source-specific emissions limits.

Commenter (0798) says, specifically, after the EPA identified "linkages" from a state to a downwind receptor based on as little as a 1 percent modeled impact on the DV, the Screening Assessment identifies industries that, without regard to those same state linkages, had over an arbitrarily set threshold of either 0.1 ppb impact on a single receptor or as low as a 0.01 ppb impact on at least 10 receptors. The commenter relates that the proposed rule then assumes that, for those industries, every source within the same industry code has a significant contribution or interferes with maintenance and thus is subject to regulation. The commenter further relates that the proposed rule then assumes that the same controls and the same efficiency, can be achieved at all of these sources, using the same technology, and at the same cost, with no consideration of the size, age, past performance, or any other individual data from any single facility or emissions unit. According to the commenter, while the EPA could support industry-wide modeling of EGUs as a sufficient basis to impose state NOx budgets in

EME Homer, the proposed rule's attempt to impose source- and emissions unit-specific emissions limits based on nothing more than generalized assumptions of what various industries that happen to be located in at least one "linked" state is untethered from any attempt to reduce significant contribution to nonattainment or interference with maintenance of the NAAQS and is patently insufficient.

Commenter (0798) states that the EPA did not comply with its 4-step interstate transport framework approach to determine whether a significant contribution to nonattainment or maintenance exists from the iron and steel industry. The commenter claims that it is therefore arbitrary and capricious to regulate the steel industry nationally rather than regulating the appropriate sources (or at least appropriate industrial sectors) in each state actually contributing to the amount of emissions that need to be reduced from that state to fulfill its good neighbor obligations. The commenter adds that the EPA also has improperly conflated its own screening threshold for whether a state as a whole has a significant enough contribution to require reductions pursuant to the FIP, with the statutory requirement to evaluate significant contributions of a "source or type of emissions activity within the State." For Arkansas, the commenter asserts that the EPA failed to show that specific sources in Arkansas are contributing significantly to the Harris County monitor or interfering with maintenance of the NAAQS at other receptors, thus the EPA is effectively contending that a 1 percent linkage is the same as a significant contribution, which is not consistent with their guidance or Clean Air Act 110(a)(2)(D)(i). The commenter notes that the determination of linkages and significant contributions occurs at separate steps in the 4-step interstate transport framework analysis and does not agree that a 1 percent linkage to an entire state is the same as a significant contribution from a source or emissions activity. Further, the commenter claims that it appears the EPA performed an evaluation of whether each industry contributed to nonattainment or maintenance issues at each states linked receptors, and then went on to propose regulation for each industry sector in each screened-in state despite finding that many industries did not contribute to that state's linked receptors above the industry significance thresholds set by the EPA. For instance, according to the commenter, the EPA's modeling found that the iron and steel industry only contributed to a nonattainment or maintenance receptor above the significance threshold in one state, and thus it would be arbitrary and unlawful for the EPA to subject the steel industry in other states to the proposed rule.

Commenter (0436) states that in parallel with the modeling limitations used to justify the inclusion of Utah in the proposed FIP, there appears to be a fundamental disconnect between the modeled emissions and the resulting prescribed controls. The commenter notes that the EPA summed all emissions from the upwind state to generate a total contribution and then the EPA determined the contributions of either the EGU or non-EGU sources to downwind areas. However, the commenter claims that these sources' total contributions to downwind states are often below the 0.70 ppb threshold used as the identifying threshold for inclusion in the FIP. For instance, the commenter relates that the state of Utah's highest contribution to the state of Colorado was found to be 1.3 ppb in Douglas County, while the combined EGU and non-EGU contributions to the same county are only 0.35 ppb. According to the commenter, this disconnect implies that the sources chosen for emissions reductions were selected based on criteria other than that solely tied to interstate transport of ozone and its precursor emissions.

Commenter (0237) states that the proposed FIP limits in California are not justified, as the EPA FIP criteria is not met for California non-EGUs. According to the commenter, the EPA states in the TSD that the Southern California (SoCal) non-EGU sources have no projected impacts on any monitors other than Yuma, AZ. Therefore, the commenter states that the SoCal non-EGU sources do not meet the FIP applicability criteria as set forward by the EPA (namely impacts on more than one monitor). The commenter claims that this is an inconsistency between the EPA's listed findings for California non-EGU and the EPA's stated methodology.

Commenter (0421) says that it appears the EPA has relied on a threshold of 1 percent of the 70 ppbv ozone standard (or 0.7 ppb) as a contribution threshold for regulating EGU sources but is relying on an even lower threshold (0.01 to 0.1 ppb ozone transport) as a basis for regulating the non-EGU industrial sources. The commenter questions whether the ambient air monitors for ozone are even accurate down to + 0.01 ppbv. In addition to these concerns, the commenter also supports the comments provided by the American Chemistry Council and the Air Stewardship Coalition which raise multiple issues and questions around the transport modeling and technical evaluations conducted by the EPA.

Commenter (0798) states that the EPA's request for comments on whether to only regulate Tier 1 industries and exempt Tier 2 industries misses the statutory mark. The commenter asserts that the EPA only has regulatory authority to prohibit amounts of emissions from a "source or other emissions activity" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State." According to the commenter, it is therefore arbitrary and unlawful for the EPA to consider regulating an industry on some other basis (such as whether the EPA considers an industry to be "Tier 1" or "Tier 2"). Accordingly, the commenter asserts that the EPA should avoid overcontrol and adhere to the statutory text by only regulating industries within a particular state which significantly contribute to that state's linked receptors, rather than by whether the EPA happens to classify the industry as "Tier 1" or "Tier 2" on a nationwide basis.

Commenter (0760) opposes the proposed FIP and claims that the EPA's identification of Tier 2 boilers as being "impactful" is not supportable. According to the commenter, the EPA counted as "impactful" any industrial boiler that had a projected contribution of > 0.01 ppb to any monitor. The commenter states that the EPA's break point of 0.01 ppb is arbitrary and capricious as it was not justified by any reasoned analysis. Commenter contends that there is an inadequate basis for imposing controls on "impactful" large industrial boilers. The commenter believes the EPA should not regulate any Tier 2 sources in Louisiana as no Louisiana Tier 2 source had a projected contribution to either of the Houston monitors greater than 0.01 ppb, noting that there was only one Louisiana Tier 2 unit that was projected to impact the Houston-Brazoria monitor at just 0.016 ppb. The commenter states that regulation of units with less than a 0.01 ppb potential contribution must be considered to be non-impactful even if NOx controls are determined to be marginally cost-effective (which is denied). The commenter asserts that the regulation of these Tier 2 Non-EGUs will make no discernable difference to the two monitors in Houston, considering the significant uncertainties in the EPA ozone projections. The commenter goes on to say that the EPA must establish a break point at which no regulation makes sense. The commenter submits that a conservative break point would be if any projected contribution is less than one, one hundredth of a part per billion. The commenter declares that the EPA's multi-factor analysis should justify any regulation of greater than that value. According to the commenter, in any rationale weight-of-evidence approach, a requirement to impose controls costing > $1 million annually for a unit that contributes less than 0.01 ppb to a monitor cannot be justified.

Commenter (0504) objects to the inclusion of non-EGU sources because the EPA did not explain or support the breakpoints it used to identify the "Tier 1" and "Tier 2" sectors and lost sight of the standard under which it is proposing to include non-EGUs in the proposed FIP. The EPA can only conclude that reducing NOx from certain upwind non-EGUs may lead to meaningful air quality improvements at downwind receptors. The EPA cannot include non-EGUs in a FIP based on this agency-constructed and entirely unexplained standard.

Response:

The EPA reasonably explained in the Screening Assessment how it identified potentially impactful industries and emissions units, and the methodology is not arbitrary. The EPA identified five air quality metrics by which to evaluate 41 industries. "These metrics were selected to provide air quality information to inform an evaluation of the magnitude and geographic scope of contributions from individual industries." Screening Assessment, Appendix A, at 22. Focusing on maximum downwind contribution (in ppb) at any receptor, the EPA rank-ordered the industries in Figure A-1. The distribution indicated a reasonable "break point" at 0.01 ppb, and we determined that industries below a 0.01 ppb impact at any receptor could be eliminated from further analysis. In further assessing the remaining industries, we ultimately found four industries that had both widespread impacts (*i.e.*, impacting more than 10 receptors at greater than 0.01 ppb) and at least one greater impact at a single receptor (*i.e.*, greater than 0.1 ppb). *Id.* at 3. These four industries ended up comprising the "Tier 1" industries. We also found that the data suggested a second tier of industries should also be evaluated. The data indicated that these industries either were capable of a particularly substantial impact to at least one receptor (*i.e.*, greater than 0.1 ppb), or had widespread impacts (*i.e.*, greater than 0.01 ppb to at least 10 receptors). For this second tier, recognizing the lesser degree of impact compared to Tier 1, we reasonably focused on the most common emissions unit type that the data indicated would be available in these industries - boilers. "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 . . ., we targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers." *Id.* at 5.

This analysis is more fully described in the Screening Assessment. However, several points bear emphasis in response to these comments. First, the Screening Assessment methodology served as a reasonable and reliable method for distinguishing potentially impactful industries from non-impactful industries, identifying only 9 out of 41 industries (as defined by 4-digit NAICS) for further evaluation.

Second, that these were estimated to be the nine potentially most impactful industries should not come as a surprise, as each of these industries typically involve large-scale fossil-fuel combustion as part of their manufacturing processes, have historically had high NO_X emissions as a result, and are projected to continue to have relatively high NO_X emissions into the future.

The large emissions profile of these industries compared to others can readily be seen in Table A-3 of the Screening Assessment.

Third, as explained in response to comments in Section 2.2.1 above, it was entirely reasonable, and consistent with prior transport rulemakings to focus the analysis at the industry-level rather than attempt to identify air quality impact thresholds at the unit- or source-specific level. To build on the response above, it is important to keep in mind that regional interstate ozone transport is a "collective contribution" problem, in which the ozone-precursor emissions of many sources combine to create ozone nonattainment and maintenance problems at potentially great distances from individual source emissions points. *See*, *e.g.*, 63 FR at 57386. Attribution of responsibility for this problem is complicated by varying meteorological conditions from year to year and even from day to day. The EPA's Step 1 and Step 2 analysis within the 4-step interstate transport framework is designed to robustly identify where ozone problems are located and which states' anthropogenic emissions contribute to those problems. At Step 3, the analysis shifts to an evaluation of which emissions reductions from those contributing states would be most cost-effective to achieve to eliminate that portion of the states' emissions that are deemed "significant" and thus must be eliminated. Focusing on entire industries (as the EPA has done in prior rules with its focus on EGUs (*e.g.*, CAIR and CSAPR)) and other industry categories in addition to EGUs (as we did in the NO_X SIP Call) presents an efficient and equitable methodology for identifying where the most cost-effective emissions reductions can be identified at the regional scale. (One aspect of the "equity" we refer to here is in assuring that direct competitors within particular industries within the geography of linked upwind states are held to the same level of emissions performance, to avoid the potential for emissions shifting or competitive disadvantages brought on by assigning transport obligations to individual sources that are not borne by their competitors.)

It was precisely this analytical framework that the Supreme Court upheld in *EME Homer City*, noting the "thorny causation problem" of interstate pollution transport, 572 U.S. at 514, the need to account for "the vagaries of the wind," *id.* at 497, and the complexity of allocating responsibility among potentially large groups of states who may each contribute to one another's air quality problems as well as to multiple other states in varying degrees, *id.* 514-16. Commenters on the Screening Assessment seem to believe that the EPA must define a precise level of emissions from each particular non-EGU source that constitutes significant contribution or interference with maintenance, in relation to the impacts of those particular emissions at each particular receptor. As the Supreme Court put it when considering such an argument in the context of the allocation of EGU emissions-reduction obligations in CSAPR, "Nothing in the text of the Good Neighbor Provision propels EPA down this path. Understandably so, for as EPA notes, the . . . proportionality approach could scarcely be satisfied in practice." *Id.* at 515.

Commenters suggest that without a more granular analysis, the EPA has not sufficiently established a connection between emissions reductions from a particular source or industry in a given state and air quality improvement at a particular receptor. This simply restates the same misapprehension addressed above. Furthermore, the analysis in both the proposal and in the final rule demonstrates that when these non-EGU emissions reductions are considered in the aggregate and coupled with EGU emissions reductions (as they should be when assessing how to solve a "collective contribution" problem), the effect on downwind air quality across the entire set of receptors is substantial and would make a meaningful step towards reaching and maintaining attainment of the NAAQS at many receptors. (See the Air Quality Modeling Final Rule TSD and the Ozone Transport Policy Analysis Final Rule TSD for further discussion and analysis.) Analyzing the effect of the actual set of proposed non-EGU emissions limits and related reductions, at proposal we estimated that on average these reductions could produce a 0.22 ppb improvement at the receptors (for a total of 0.64 ppb in average improvement when coupled with the EGU emissions control strategy). *See* 87 FR at 20096-97. (See Section V.D of the preamble and response to comments in Section 2.2.1 above for comparable estimates for the final rule.)

Commenters misstate or confuse the relationship between the Screening Assessment air quality thresholds used for non-EGUs and the use of 1 percent of NAAQS contribution threshold at Step 2 of the 4-step interstate transport framework. Once a state is found linked at Step 2, the EPA proceeds to an evaluation of emissions reduction opportunities at Step 3. The EPA is not replacing the 1 percent of NAAQS threshold used at Step 2 with a different threshold at Step 3, nor are we using a different Step 2 threshold for states with EGU reductions versus non-EGU reductions. There is no conflict or contradiction between the Step 2 threshold and the air quality thresholds used in the Screening Assessment when considered in relation to the respective roles they play within the larger analytical framework.

Commenters make unfounded and incorrect statements that the EPA lept from the results of the Screening Assessment to mandating all of the emissions reductions precisely as they had been identified that were below the $7500/ton threshold for each covered industry, without further analysis. This is not true, either at proposal or in the final rule. At both proposal and final, we developed regulatory requirements that reflected a more detailed assessment of appropriate emissions-control technologies for the relevant industries, as described in response to comment 2.2.1 above. We have been clear throughout the rulemaking record that the results of the Screening Assessment should not be confused with regulatory requirements, applicability determinations, or emissions limits. We fully acknowledge that the final rule's emissions control obligations for the non-EGU industries may be different from the controls and emissions reductions estimated in the Screening Assessment; this reflects an improved understanding of emissions control opportunities, particularly in consideration of comments from the potentially regulated entities. These adjustments do not undermine our antecedent findings, via the Screening Assessment, that these industries and emissions units warranted evaluation for appropriate, cost-effective emissions control opportunities.

Regarding the comments that the approach of identifying tiers of industry sources does not adequately comport with the statutory obligation to eliminate significant contribution from each upwind state, the Agency again disagrees for the reasons already stated. The analysis focused on industries and emissions unit types that measurably impact one or more identified nonattainment or maintenance receptors. The distinction between Tier 1 and Tier 2 industries in the Screening Assessment is also reasonable and well-explained. As explained in the Screening Assessment and in response to comments above in Section 2.2.1, the EPA in this rule continues to recognize (as it had in the NO_X SIP Call) that ICI boilers are a uniquely impactful unit-type with well-understood and cost-effective NO_X emissions control technologies. Thus, focusing on these units within the second tier of industries was a reasonable decision and consistent with our prior transport rules.

Comments:

Commenter (0504) states that the EPA's aggregation of dissimilar industries to assess "significant contributions" is unreasonable, unsupported, and unexplained. According to the commenter, the EPA's screening assessment approach involving aggregating industries defined by 4-digit NAICS is impermissible, as SIPs and FIPs can only limit emissions to address significant contributions from either individual sources or types of emissions activity. The commenter claims that the NAICS does not categorize businesses on the type of emissions activity, which should be construed as referring to sources that operate the same emissions units, exhibit similar emissions profiles, and share similar emissions control opportunities. The commenter asserts that the EPA's decision to define industries by 4-digit NAICS codes rather than "type of emissions activity" without first establishing why the 4-digit NAICS codes are relevant to distinguish and discern between the "type of emission activity" therefore directly contradicts the express text of the CAA. The commenter notes that this grouping results in industry sectors falling into the same 4-digit NAICS that do not have the same type of emissions activity, which is plainly unreasonable and disregards the express text of the CAA and.

Commenter (0360) states that electric arc furnaces (EAFs) should not be included in the proposed FIP. The commenter claims that relative to other sources, EAF emissions do not significantly contribute to downwind nonattainment. On this note, the commenter specifically endorsed certain comments made by other commenters, including: for NAICS 3311, nearly all the linked contributions identified in the EPA's screening assessment were from Integrated Iron and Steel facilities—not EAF mills, yet because the EPA grouped facilities by NAICS, EAF mills within NAICS 3311 are subject to the proposed controls; the EPA's own modeling confirms that steel industry sources and EAF sources simply do not contribute significantly to any downwind nonattainment in any state; and EAF steelmakers in 23 states may be suddenly thrust into an unprecedented and infeasible new regulatory scheme deemed unnecessary and unworkable by 19 states and, quite recently, the EPA itself. These comments were made by ASC and the Steel Manufacturers Association and the Specialty Steel Industry of North American on this rulemaking.

Commenter (0798) says that the EPA properly excluded the Taconite Industry from the proposed rule. The commenter noted that the metal ore mining Industry was originally included as a Tier 2 industry group, but in a later step in the analysis, the EPA refined the Tier 2 grouping by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers. The commenter notes that this eliminated the metal ore mining industry group from the assessment, as the EPA found that it had no "potentially impactful" boilers. The commenter remarks that according to the EPA's assessment, boilers in the metal ore mining industry, which would include the taconite industry, do not provide opportunities for NOx emissions reductions that result in meaningful impacts on air quality at downwind receptors.

Response:

The EPA disagrees with the commenter that grouping industries by NAICS code is inherently unreasonable or that the EPA's framework for assessing whether industries have "potentially controllable" NOx emissions is irrational and inconsistent. The EPA used 2019 emissions inventory data reported by state/local/tribal authorities to assess a large and varied number of industries and emissions unit types that could potentially impact downwind receptors. Given the large number of states, receptors, industries, and emissions unit types, the EPA prepared a reasonable analytical approach. See responses to comments in Sections 2.2.1 and 2.2.2 above. The EPA notes that the commenter did not offer an alternative method for assessing potentially impactful industries and emissions units.

We note that commenters (0504) and (0360) are particularly concerned about the inclusion of EAF units in the proposed rule. For reasons explained in Section VI.C.3 of the preamble and Section 4 of the Final Non-EGU Sectors TSD, we are not finalizing control requirements for these units.

Regarding commenter (0798)'s claims that boilers in the taconite industry (NAICS 212210, which is part of the Metal Ore Mining industry, NAICS 2122) do not present meaningful and cost-effective emissions reduction opportunities, we disagree, and these unit types are included in the final rule. At proposal, our analysis suggested that there were not any boilers in this industry, or in the Lime and Gypsum Product Manufacturing industry, but we explained that if such units meeting applicability criteria were found, then we would cover them in the final rule. 87 FR at 20148. The final rule analysis has identified boilers in the Metal Ore Mining industry, and so these units are included to the extent they meet the final rule's applicability criteria. The Screening Assessment reasonably identified Metal Ore Mining as an impactful industry in consideration of the degree of impact that its potentially controllable emissions have on receptors. Then, as a Tier 2 industry, the Screening Assessment focused on potential emissions control opportunities at boilers. See response to comments in 2.2.1 and 2.2.2 above. Thus, while Metal Ore Mining may have relatively few boiler units, this industry as a whole was nonetheless found to be impactful, and this rule focuses on boilers as the most impactful emissions-unit types with cost-effective emissions reduction potential within the Tier 2 industries as a whole. In addition, to the extent such boiler units are used at facilities within any of the other impactful industries covered by the rule (this is the case for Iron and Steel Mills and Ferroalloys Manufacturing), because these boilers have a similar profile in terms of having well-understood, cost-effective emissions reduction potential, they too are covered in this final rule. We note that the commenter does not advocate nor supply information regarding more cost-effective opportunities to limit ozone season NO_X emissions within the Metal Ore Mining industry.

Comments:

Commenter (0382) says the EPA's approach might make sense if it actually defined "well-controlled sources" and supported its definition with evidence. But the EPA does neither. The Non-EGU Memorandum mentions the term "well-controlled sources" just once and offers no support for the suggestion that the EPA cannot meaningfully regulate "well-controlled" sources at a reasonable cost. In fact, the only time the memorandum assesses emissions from sources other than the seven targeted industries is in Figure 1, a chart that shows around 20,000 tons of NOx emissions attributable to sources other than the seven targeted industries. The twenty thousand tons of NOx emissions produced by these other industries constitute more than 20 percent of the emissions generated by the seven targeted industries. Yet, other than stating that these non-targeted businesses are already "well-controlled," the EPA offers no analysis as to why they avoided regulation when other industries did not. The EPA's approach is tantamount to saying "trust us," which, absent explanation, federal courts have found arbitrary and capricious. [citing *Ergon-W. Va., Inc.,* 980 F.3d at 422 (citing *Roe*, 947 F.3d at 220); *Vigil*, 381 F.3d at 845 (referencing *Sierra Club*, 294 F.3d at 163); *Ergon-W. Va., Inc*., 980 F.3d at 421 (finding the EPA's decision arbitrary and capricious, in part, because the EPA scored similarly situated companies differently and offered no applicable explanation).

Commenter (0266) requests additional details and clarity on the screening process the EPA used to assess non-EGUs, specifically regarding the criteria used to determine if a source was well controlled and the emissions threshold triggering the applicability of this rule for the iron and steel industry.

Commenter (0382) and commenter (0798) note that the EPA's explanation for including non-EGU industries is that they emit over 100 tons per year (tpy) of NOx and that "well controlled sources" were excluded because uncontrolled sources can be better controlled at a reasonable cost. The commenters claim that the EPA did not define "well controlled sources" or support a definition with evidence, nor does it support the suggestion that "well controlled sources" cannot be regulated at a reasonable cost. Commenters (0382, 0798) state that without explanation, the EPA's approach is tantamount to saying, "trust us," which federal courts have found arbitrary and capricious.

Commenter (0421) declares that the EPA should reconsider its proposal to impose controls on the industrial boilers covered by this proposed rule. The commenter notes that boilers in the chemical manufacturing industry are highly regulated under federal and state law and state air permits to control NOx emissions and have already taken measures to reduce emissions under CAA regulations and SIPs.

Response:

The commenters are incorrect that the EPA did not identify what it meant by "well-controlled" sources in the Screening Assessment. We used data from the Control Strategy Tool (CoST), the Control Measures Database (CMDB), and the 2023 emissions inventory to understand the degree of existing emissions control on sources in the Tier 1 and 2 industries, and what additional emissions controls could be available to these sources. *See* Screening Assessment at 4. All of this information is available in the docket or publicly available online. We used representative cost-per-ton estimates for potentially available additional control technologies to plot a "knee in the curve" graph, which showed that, in general, a $7500/ton marginal cost-effectiveness value represented a point below which cost-effective emissions reductions could be achieved, and beyond which cost-effectiveness quickly tapered off. *See id.* Figure 1. Commenter claims that the EPA improperly did not further evaluate an additional 20,000 tons of emissions reduction available from non-Tier 1/Tier 2 industries, but this is mistaken. Those industries had already been identified as not having "impactful" emissions at the step in our analysis when industries were evaluated for impacts on downwind receptors (maximum contribution to any one receptor of >0.10 ppb and/or contribute >= 0.01 ppb to a certain number of receptors). *See id.* at 2-3. In Appendix A ("Analysis of Industry Contribution

Data”), the EPA provided more information related to its analysis of other non-EGU industries. That analysis explained why the other non-EGU industries were not evaluated further. Table A-3 showed ozone season emissions that could potentially be reduced from all industries analyzed, and it can be seen there how the additional potential emissions reductions commenter mentions are distributed across other industries. These other industries generally had fewer sources with emissions greater than 100 tons per year, and/or impacted identified receptors to a much lesser degree than the Tier 1 and 2 industries. The EPA reasonably determined that it would not make sense to pursue these emissions-reduction opportunities further.

Comments:

Commenter (0798) says given that the standard deviation for any CAMx prediction at the Brazoria receptor was up to 8 ppb, it is not reasonable or rational for the EPA to rely on CAMx to make fine-tuned distinctions between industries modeled to have impacts at 0.01 ppb (the screening level selected by the EPA for industry significance), since EPA’s own analysis shows that the model is simply not precise enough to statistically differentiate between 0.01 ppb, 0.1 ppb, and 1 ppb. Commenter (0798) continues, the EPA’s communications discussed in the attached Woodard report demonstrate that the EPA was aware of model “noise” due to model outputs being copied and handled over multiple operating systems and that numerical noise in model outputs could be present and could contribute to variations in modeled concentrations. If that noise was on the order of 0.01 ppb, that would be yet another reason that the modeling could not be relied on to differentiate between impacts at that level of granularity, and thus that such a level below background “noise” cannot be considered significant. Accordingly, the EPA should base any determinations of modeled significance at a precision no smaller than 1 p[p]b, so as to at least be within the same order of magnitude as the model’s standard deviation.

Commenter (0437) struggled to understand how the EPA determined pulp and paper boilers should be included in this rule, especially considering that the contribution threshold of 0.01 part per billion (ppb) at a downwind receptor is not even measurable. According to the commenter, the EPA’s background documents, and screening analysis do not support the expansive coverage proposed in the regulatory language.

Commenter (0504) notes that regarding the impacts of NOx emissions on downwind ozone receptors/monitors, the combined NOx emissions reduction estimated from the EAF sources is just 3 percent of the Iron and Steel sector sources and would be far smaller if compared to the total Tier 1 reductions, or the combined reductions from all sources in the proposed FIP. The commenter goes on to say that the EPA’s modeling data show that including all iron and steel sector sources would only result in changes at monitors in the East, where the maximum ozone impact is 0.175 ppb from the iron and steel industry. The commenter remarks that 0.175 ppb of ozone is not measurable with any reliability at any monitor. The commenter also remarks that the specific ozone impacts the EPA modeled at individual downwind state monitors from all sources in the iron and steel sector, the one monitor with an ozone level greater than 0.1 ppb is the Sheboygan, WI monitor, with a total steel industry contribution of 0.1292 ppb. At the four monitors where the EPA has indicated impacts from the two EAF mills, the combined contribution from all of the iron and steel sector sources does not exceed 0.035 ppb, which the commenter reiterates is not a level of ozone that is discernable by any measurement at these monitors. The commenter also notes that in the EPA's estimated ozone contribution from specific plants or mills, the range of ozone levels from NOx emissions at the two modeled EAF mini-mills range from 0.0001 ppb to 0.0012 ppb. The commenter states that it that these predicted levels of ozone are not capable of being measured with any level of accuracy and are insignificant by any measure.

Commenter (0320) states that even if the reductions the EPA predicts for Tier 2 boilers are feasible, the air quality improvements the EPA anticipates at individual receptors are immeasurable by current ambient air quality monitoring systems. The commenter notes that the EPA has chosen to regulate non-EGU boilers in the chemical industry because it has calculated (not modeled) that these boilers either have a maximum contribution to any one downwind receptor that is greater than or equal to 0.10 ppb or they contribute greater than or equal to 0.01 ppb to at least 10 downwind receptors. The commenter provides that in Table 2 of the EPA's non-EGU screening assessment, the maximum improvement at any receptor from controls on all Tier 2 boilers (in all proposed source categories) is 0.169 ppb. The commenter notes that in Table 5 on page 16 of the same memo, the maximum estimated improvement for any receptor from controls on Tier 2 boilers is listed as 0.0258 ppb. Additionally, the commenter notes that a further review of the spreadsheet "Transport Proposal - Tier 2 Boiler Analysis - 03-16- 2022.xlsx indicates that the average improvement is 0.016 ppb considering the impact of reductions from all Tier 2 boilers at a single receptor. The commenter states that current ambient air quality monitoring systems have a detection limit of approximately 0.3 ppb which is an order of magnitude greater than the EPA's maximum calculated improvement from controlling Tier 2 boilers. According to the commenter, if the EPA were to finalize the rule as proposed, Tier 2 industries would be required to spend $54.2 million per year (according to the screening assessment memo) for results that are too insignificant to even measure, meaning there is no quantifiable downwind benefit to controlling Tier 2 boilers.

Response:

Commenters essentially argue that the 0.01 ppb threshold used to remove industries from further evaluation in the Screening Assessment is beyond the limits of modeling and monitoring capability. First, these arguments misunderstand the purpose of the Screening Assessment analysis. The purpose is not a precise replication of exactly which sources contributed exactly how much to any particular receptor during a particular high-ozone event. The purpose is to identify those industries with relatively large emissions sufficient to have interstate effects on ozone levels, and to analyze emissions units within those industries further for cost-effective emissions reduction opportunities. The EPA used AQAT in the Screening Assessment to make reasonable projections of air quality impacts to allow for comparison among the different industries that were analyzed.

Second, the EPA's modeling techniques for conducting this analysis are within parameters for acceptable model performance. Response to comments regarding the reliability and usefulness of AQAT are addressed in Section C.4 and C.5 of the Ozone Transport Policy Analysis Final Rule TSD and Section 10.3 (Comments about AQAT), and comments regarding the reliability and usefulness of the CAMx modeling are generally addressed in Chapter 3 of this document.

We note that in *Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000), the court held that the EPA needed to establish a "measurable contribution" before identifying the amount of "significant contribution." *Michigan*, 231 F.3d at 684. The court there was reviewing a record in which the modeling on which the EPA was relying for the identification of "significant contribution" did not extend to the entirety of two particular states (Missouri and Georgia). The court found there was nothing in the record to support a conclusion that emissions from those regions of those states were significantly contributing. Here, by contrast, the EPA's Screening Assessment encompassed an evaluation of 41 non-EGU industries within the borders of each linked upwind state. The record establishes that the impactful non-EGU industries and emissions unit types covered in this final rule have measurable contributions to out of state nonattainment and maintenance receptors. Commenters' arguments that any particular source could be shown not to have an impact above a certain threshold such as 0.01 ppb miss the mark. The court in *Michigan* in fact recognized the fallacy in this line of reasoning and made clear it was not holding the EPA to proving each individual increment of emissions activity must itself constitute significant contribution. *See* 213 F.3d at 684 ("[U]nlike bologna, which remains bologna no matter how thin you slice it, significant contribution may disappear if emissions activity is sliced too thinly.").

Other commenters argue that the projected improvements in air quality are beyond the capabilities of air quality monitoring equipment. The analysis in the Screening Assessment does not depend on air quality monitoring instruments' precision of measurement. We address other comments on whether monitoring technology capability is relevant in Section IV.F of the preamble. It bears repeating in the context of the Screening Assessment that the impacts of emissions at very small ppb increments can be calculated through our modeling techniques for the purpose of assessing the relative impacts of various emissions sources and to apportion responsibility for "significant contribution." In upholding the EPA's approach to evaluating interstate transport in CSAPR using modeling, 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 II*, 795 F.3d at 135. "[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 the 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)).

Finally, while we find the modeling techniques used to inform this rule sufficiently reliable even when used to project changes in air quality in an absolute sense (as explained elsewhere in the record), we note that in the context of the Screening Assessment, these techniques were applied for purposes of conducting a comparative analysis among different industries. Thus, whatever "noise," or "margin of error" or other imperfections are alleged to exist within the modeling, because these would apply consistently and equally to each industry the EPA evaluated, they don't affect the reliability of the results in relation to the purpose of this analytical exercise.

Comments:

Commenter (0758) states the EPA identified five additional industries that either contribute >= 0.1 ppb to any one receptor or >=0.01 ppb to at least ten receptors, including: chemical manufacturing; petroleum and coal products manufacturing; metal ore mining; lime and gypsum product manufacturing; and pulp, paper, and paperboard mills. While these industries contain a variety of emitting units, such as boilers, internal combustion engines, or other industrial process units, the EPA, however, proposes to require NO_X reductions only from boilers within these industries "because boilers represent the majority emissions unit in the Tier 2 industries for which there were controls that cost up to $7,500." And, because the metal ore mining and lime/gypsum product manufacturing sectors do not have boilers of a relevant size, the EPA excludes reductions from these industries entirely.

Commenter (0758) continues, reductions from emissions units other than boilers in these industries are cost effective. The EPA's analysis shows that there are a significant number of industrial processes (77, including 48 in petroleum and coal products manufacturing alone) and internal combustion engines (14) in Tier 2 industries with controls that cost up to $7,500 per ton (compared to 132 boilers).

The commenter (0758) also declares that the EPA should further explain the rationale behind its approach to "Tier 2" of its regulatory structure for non-EGUs and consider whether it should apply emissions limitations to a broader range of sources in this tier. The commenter reports that after running its Control Strategy Tool analysis, the EPA concluded that most non-EGU units that it had not already selected as "Tier 1" sources were boilers and thus decided to limit its Tier 2 coverage to boilers. The commenter states that the fact that boilers comprise the majority of relevant emissions units does not preclude the EPA from regulating other source types as well. As reported by the commenter, the remaining 41 percent of potential Tier 2 emissions units cover 14 internal combustion engines and 77 industrial processes and could be responsible for significant collective emissions. Therefore, the commenter recommends that the EPA either further explain its decision not to regulate non-boiler Tier 2 emissions units or consider regulating such units in its final rule or future rulemakings.

Commenter (0758) argues the EPA must not arbitrarily exclude reductions from emissions units other than boilers, or exclude reductions from the metal ore mining and lime/gypsum product manufacturing industries. Large industrial units in the metal ore mining and lime/gypsum product manufacturing, which the EPA claims exclude boilers, emit more ozone season NO_X than chemical manufacturing; petroleum and coal products manufacturing; and pulp, paper, and paperboard mills combined. The EPA finds that the metal ore mining and lime/gypsum product manufacturing industries, like the basic chemical manufacturing; petroleum and coal products manufacturing; and pulp, paper, and paperboard mills industries, contribute >= 0.1 ppb to any one receptor or >=0.01 ppb to at least ten receptors, and may not arbitrarily exclude reductions from these two industries.

Commenter (0538) supports the EPA's inclusion of non-EGU sources in the rule, but states that more explanation for its selection of non-EGU sources is needed. According to the commenter, the proposed FIP's extension of good neighbor obligations to non-EGU sources is consistent with statutory text, regulatory precedent, and caselaw. The commenter says that the broad statutory text of the good neighbor provision, the EPA's long history of interpreting the provision to include non-EGUs, and judicial statements on review of good neighbor rules all support the EPA's authority to regulate non-EGU emissions sources. However, the commenter believes the EPA should further explain how it decided which non-EGUs to include in the proposed FIP. The commenter declares that the EPA should further explain the rationale behind its approach to "Tier 2" of its regulatory structure for non-EGUs and consider whether it should apply emissions limitations to a broader range of sources in this tier. The commenter reports that after running its Control Strategy Tool analysis, the EPA concluded that most non-EGU units that it had not already selected as "Tier 1" sources were boilers and thus decided to limit its Tier 2 coverage to boilers. The commenter states that the fact that boilers comprise the majority of relevant emissions units does not preclude EPA from regulating other source types as well. As reported by the commenter, the remaining 41 percent of potential Tier 2 emissions units cover 14 internal combustion engines and 77 industrial processes and could be responsible for significant collective emissions. Therefore, the commenter recommends that the EPA either further explain its decision not to regulate non-boiler Tier 2 emissions units or consider regulating such units in its final rule or future rulemakings.

Response:

The EPA has explained in response to comments earlier in this section how its Screening Assessment methodology reasonably guided the Agency to identify impactful industries and unit-types for further evaluation of emissions control opportunities, and in particular the decision to focus on boilers in the Tier 2 industries. These comments observe that within the Tier 2 industries in the Screening Assessment, there may have been cost-effective emissions control opportunities from non-boiler unit types, but the EPA only focused on boilers in these industries, thus potentially overlooking other cost-effective emissions control opportunities. The Agency agrees that such additional, cost-effective emissions reduction opportunities may exist within these industries. And we note that states interested in replacing the FIP with a SIP may choose to explore whether to require emissions reductions of an equivalent or greater degree at such unit types. (See Section VI.D of the preamble.) However, the data available to the Agency for the Screening Assessment did not indicate sufficient emissions-control potential that could be applied, and the commenters here have not supplied information with sufficient "reasonable specificity" to call into question the Agency's reasonable choice to focus on boiler units in the Tier 2 industries. It was also reasonable for the EPA to limit emissions control requirements in Tier 2 industries to boilers, given the relatively lesser level of impact estimated compared to Tier 1 industries.

2.2.3 Screening Assessment -- 100 TPY Threshold

Comment:

Commenter (0758) asserts that the EPA should also consider reductions from non-EGU units that emit less than 100 tons of NOx per year. According to the commenter, the EPA has considered non-EGU point sources with NOx emissions greater than 25 tpy, and the Agency identified 438 gas turbines and 350 gas boilers across 37 eastern states with NOx emissions between 25 to 100 tpy. The commenter reports that the EPA found that those units had potential NOx reductions of 7,193 tons and 6,814 tons respectively (14,007 tons combined). The commenter states that the EPA has statutory authority to consider these sources, as the good neighbor provision extends to "any source or other type of emission activity" that significantly contributes to downwind nonattainment or interferes with downwind maintenance. The commenter also points out that the agency has recognized that the problem of interstate ozone pollution is driven by "collective impacts of relatively small contributions." For that reason, the commenter suggests that the Agency consider reductions available from units with NOx emissions greater than 25 or 50 tpy.

Commenter (0538) supports the EPA's inclusion of non-EGU sources in the rule, but states that more explanation for its selection of non-EGU sources is needed. According to the commenter, the proposed FIP's extension of good neighbor obligations to non-EGU sources is consistent with statutory text, regulatory precedent, and caselaw. The commenter says that the broad statutory text of the good neighbor provision, the EPA's long history of interpreting the provision to include non-EGUs, and judicial statements on review of good neighbor rules all support the EPA's authority to regulate non-EGU emissions sources. However, the commenter believes the EPA should further explain how it decided which non-EGUs to include in the proposed FIP. Specifically, the commenter states that the EPA should provide more detail on its decision to consider regulation of non-EGU sources only if they emitted more than 100 tpy of NOx and its decision to eliminate any sources of emissions that it considered to already be well-controlled.

Commenter (0353) remarks that the proposed rule includes significant changes in the EPA's prior approach to the regulation of stationary engines when compared to prior CSAPR regulations and does not provide a sufficient explanation as to why the EPA is significantly deviating from its prior practices. The commenter notes that this includes changes to both the annual NOx emissions threshold for evaluating non-EGU sources and the marginal cost threshold for assessing pollution controls. The commenter says that the EPA does not explain why it reduced the threshold to 100 tpy of NOx compared to the previous value of 150 tpy.

Commenter (0504) asserts that the EPA's framework for assessing whether industries have "potentially controllable" NOx emissions is irrational and inconsistent. According to the commenter, simply assuming that sources with over 100 tpy of NOx are uncontrolled and could be controlled at a reasonable cost is an unexplained, unreasonable, and arbitrary assumption. The commenter also states that the EPA failed to explain why it did not use another threshold, such as the 150 tpy it used just one year ago for the CSAPR Rule Update. The commenter noted that the EPA estimated this threshold would be equivalent to an EGU with over 25 MW electric generating capacity, which is the EGU capacity size that the trading program would be restricted to. The commenter declares that the EPA has not supported that NOx emissions sources below 100 tpy are well-controlled and does not justify this threshold for program inclusion.

Commenter (0508) believes that the EPA did not provide sufficient evidence/support for the use of the >100 tpy screening assessment threshold and recommends that the EPA justify the limit in the final FIP.

Commenter (0344) is concerned about the applicability thresholds in the rule, noting that the applicability thresholds are not uniform within the rule and that some smaller sources that do not significantly contribute to NOx emissions at various receptors are brought into the rule. According to the commenter, in the steel mill category, each combustion unit at a BOF Shop would be applicable to this rule, even if a unit emits less than 100 tons per year NOx; however, in other source categories, the applicability threshold is based on whether the source as a whole emits or has the potential to emit 100 tons per year.

Commenter (0554) states that the EPA does not explain why 100 tpy is an appropriate threshold for identifying units warranting regulation or why it is using a lower threshold than the 150 tpy relied upon in the recent Revised CSAPR Update. The commenter further states that unlike the 100 tpy threshold that the EPA used in the proposed rule, the 150-tpy threshold in the Revised CSAPR Update had a logical and well-explained basis, noting that the EPA explained that units with pre-control NO_X emissions greater than 150 tpy is an emissions threshold comparable to the emissions of 25 MW EGUs used in prior interstate transport rulemakings. The commenter asks that the EPA return to its 150 tpy threshold so that RICE are regulated on an equal footing with EGUs.

Response:

The use of the 100 tpy emissions unit size threshold in the Screening Assessment was a reasonable way to identify industries with emissions units that would be "more likely" to have cost-effective emissions reduction potential. We explained in the Screening Assessment:

> We focused on assessing emissions units that emit >100 tpy of NOx. 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.

Screening Assessment at 3. We note that the purpose of this emissions unit size threshold was not definitively to exclude all emissions units with less than 100 tpy emissions from being subject to emissions control requirements in this rule, nor was this step in the analytical exercise intended to function as a definitive applicability criterion. The purpose was to allow the Agency to focus on those emissions units "more likely" to have cost-effective emissions control opportunities, before proceeding to conduct further analysis on appropriate proposed emissions controls.

We acknowledged this was a lower threshold than we had used in conducting a non-EGU assessment for the 2008 ozone NAAQS, where we had used a 150 tpy threshold. As commenter observes, we previously viewed a 150 tpy threshold as comparable to the applicability criteria used for EGUs in prior transport rules. *See* 86 FR at 23098. However, the 2015 ozone NAAQS is a more protective air quality standard and so it is reasonable to look at a potentially wider universe of emissions units for potential control opportunities.

Further, using an emissions unit size threshold of 100 tpy roughly corresponds to the definition of "major source" used in the CAA (although our analysis focused on actual emissions rather "potential to emit" emissions). *See, e.g.,* CAA section 302(j) & (x). Nonetheless, the EPA is not constrained under the good neighbor provision to look only at major sources, because the provision extends to other “emissions activity” with no size limitation specified. *See* CAA section 110(a)(2)(D)(i). Nor was it necessarily more well-reasoned or justified to use 150 tpy rather than 100 tpy, simply because a 150 tpy level of emissions could be viewed as comparable to the emissions potential of a 25 MW EGU; further, the 150 tpy reflects a “potential to emit” emissions level associated with 25 MW EGUs and is not directly comparable to the 100 tpy actual emissions level for non-EGUs used in the Screening Assessment. This can be seen in considering commenter’s claim that a 150 tpy threshold is needed to put RICE units on an equal footing with EGUs. RICE used in pipeline transportation of natural gas comprise many of the non-EGU units that are covered by this rule and are estimated to deliver substantial emissions reductions, due to the large number that are in service and the quantity of emissions reductions that are achievable through cost-effective technologies applied to this group of sources. The EPA is well within its legal authority to evaluate these sources for emissions reductions to eliminate significant contribution, even if they have an operating profile different from EGUs.

The EPA notes that the Screening Assessment was intended to identify potentially impactful industries and emissions unit types for further evaluation. In the Screening Assessment we presented an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026. This provides a reliable method to identify impactful industries (identified in Step 1 of the analytical framework presented in the Screening Assessment). The proxy estimates for emissions unit types, emissions reductions, and costs from the Screening Assessment are distinct from the applicability criteria in the final rule. As explained in the Final Non-EGU Sectors TSD, the regulatory applicability criteria are intended to roughly correspond with the 100 tpy threshold used in the Screening Assessment, but also reflect other considerations such as typical applicability criteria already in use in other regulatory programs or which are familiar to the regulated sources, and/or otherwise easy to implement or understand.

2.2.4 Screening Assessment -- $7,500/ton Threshold

Comments:

Commenter (0280) states SCR is not cost-effective for reheat and annealing furnaces, ladle preheaters and tundish preheaters, grossly exceeding the $7,500/ton threshold.

Commenter (0221) states the EPA has used a cost/ton threshold for economic reasonableness of $7,500. However, as an example, the costs to install a single discharge point for a ridge vent baghouse, ducting costs, and maintenance costs would be far higher than $7,500/ton.

Commenters (0298, 0504, 0518, 0782) state the $7,500 threshold is unsupported. Commenter (0504) advocates instead for performing the analysis separately for each “type of emissions activities.”

Commenter (0298) states that the EPA’s decision to set a $7,500/ton marginal cost threshold for all non-EGUs, despite acknowledging the heterogeneity of industry, emissions unit types and control options, fails to consider the actual costs associated with achieving the proposed reductions at discrete subclasses like the ferroalloy industry and comingles unrelated industries to artificially inflate the marginal cost threshold to justify otherwise cost-prohibitive NO_X control technologies. Commenter (0518) asserts that the EPA has provided no explanation for why the Tier 1 and 2 industries were subject to different contribution thresholds yet were combined when developing the cost-effective control threshold. Commenter (0782) suggests that the variability in unit type, size, use, etc. requires the EPA to conduct unit specific analyses for the non-EGU cost threshold.

Commenters (0299, 0513) conduct their own research and conclude that SCR was not a cost-effective control technology and would only result in a further reduction of 921 tons of NO_X at a cost greater than $16,143 per ton. At least one commenter states that the rule is based on outdated and incomplete information regarding cement kilns that impacts the EPA's assumptions regarding costs.

Commenters (0301, 0549) state the EPA uses representative cost estimation methodologies to forecast control costs. These cost estimates consistently underestimate the true cost of installing control equipment at affected facilities. This is especially true today as the economic assumptions (*i.e.*, inflation, discount rate, fuel prices, commodity prices) are very different in June 2022 than in 2021. In addition, the EPA relies on a non-EGU NO_X control cost threshold of $7,500/ton but the commenter provides an example of MWC SNCR cost-effectiveness of $12,100/ton.

Commenter (0314) states the EPA averaged the estimated cost of controls across all industries and determined that a cost of $7,500 to capture one ton of ozone is reasonable. However, the EPA also conducted analyses specifically for pipelines and refineries and found any cost above $1,500 to be unreasonable.

Commenter (0318) conducted review and the results support the $7,500 threshold. The commenter is drafting a memo to pursue additional NO_X reductions from MWCs.

Commenter (0320) performed a screening type analysis of the cost of SCR on their coal-fired boilers using the EPA's OAQPS Control Cost Manual methodologies. These screening analyses show that NO_X controls come at significant cost for industrial boilers and do not agree with the EPA's estimate of $2,245 for application of SCR to an industrial coal-fired boiler.

Commenters (0340, 0314) state CoST was not created to be used for unit-specific/engineering analysis, but for "illustrative control strategy analyses." However, the EPA used CoST to develop estimates for annual control costs for non-EGUs and provides those estimates in the screening assessment. There is variance in costs, and it may hurt certain industries.

Commenter (0350) states the EPA's cost data is outdated, and the EPA does not account for inflation. The commenter also provides examples to demonstrate that the $7,500 threshold is not economically feasible in almost all instances for engines. The commenter estimates the fleetwide cost to be an average of $4.3 million per engine.

Commenter (0405) states their belief that the EPA has incorrectly applied its own data to determine the cost threshold (for categorizing Tier 1 industries) to evaluate emissions reductions related to the iron and steel sector. According to the commenter Tier 1 industries, including the iron and steel sector, have a much lower marginal cost threshold than the $7,500 per ton value and there is no technical basis to treat cost effectiveness threshold for Tier 1 and 2 industries similarly especially when data indicates or supports the opposite conclusion. Additionally, the commenter believes that the EPA's basis for imposing controls on Tier 1 sources does not satisfy the mandate of the good neighbor provisions or demonstrate that the control requirements being proposed are cost effective and consistent with the judicial mandates of the U.S. Supreme Court.

Commenter (0405) states that they performed an internal economic evaluation to determine whether the cost-effectiveness of the EPA's suggested controls in the proposed FIP align with the EPA's stated cost-effectiveness basis, specifically $7,500/ton. The commenter briefly describes the approach used and states its findings – that the cost-effectiveness for affected units is significantly above the EPA's suggested cost-effectiveness threshold in the proposed FIP (*i.e.,* $7,500/ton), making installation on these units economically unreasonable.

Commenter (0416) states NO_X control technology of the extent necessary to achieve the emissions limits is not economically reasonable for most of the iron and steel emissions units. The commenter provides examples of infeasibility. The commenter also assessed the data and claims that the "knee in the curve" for Tier 1 sources occurs at a cost of approximately $1,000 per ton at which point the ozone season NO_X reduction potential is in excess of 50,000 tons. Increasing the cost threshold to $7,500 per ton (approximately a 700 percent increase in cost) does nothing more than increase the NO_X reduction potential by approximately 15 percent more than would be achieved at the $1,000 per ton threshold.

Commenter (0437) provides example calculations to demonstrate that $7,500 is too low for boilers in the pulp and paper industry to achieve the proposed required emissions limits. Their estimated ozone season control costs for pulp and paper sector boilers averaged about $70,000/ton and generally ranged from about $11,000/ton to over $200,000/ton with a sector wide total capital cost for controls of over $700 million and an annual ozone season cost over $90 million and a total annual ozone season cost of about $38,000/ton.

Commenters (0516, 0504, 0518) request justification on the $7,500 threshold for non-EGUs.

Commenters (0308, 0798) state the $7,500 threshold does not include retrofit costs.

Commenter (0353) says that the EPA does not explain why it used a marginal cost threshold of $7,500 per ton of NOx reduced rather than the previous value of $2,000. The commenter also states that the proposed rule relies on a cost threshold for non-EGU pollution controls justified by an assessment that does not appear to be in the docket, or at least cannot be identified after a reasonable effort. The commenter remarks that the proposed rule frequently fails to clearly present key information, opting instead to generally refer the reader to the 200 or so supporting documents in the rulemaking docket. The commenter declares that requiring the reader to roam through a docket full of technical papers and spreadsheets significantly hinders the public's ability to comment on the proposed rulemaking. According to the commenter, the EPA has either failed to provide the public with access to necessary information to support the proposed rule, or it lacks that information necessary to support the proposed rule.

Commenter (0320) believes based on recent reviews of available controls for their boilers, no add-on NO_X controls are available at $7,500/ton or less, and if the EPA used its own recently updated OAQPS Control Cost Manual methodologies for SCR, its analysis would show this as well. The EPA's over-control analysis is therefore inaccurate because it does not consider all impacts of the proposed rule and likely underestimates the cost of the rule. The EPA should re-evaluate both the impacts of the proposed rule and whether or not the Agency's proposal constitutes over-control by considering the impacts, cost, and emissions reductions for all non-EGU boilers potentially subject to the proposed emissions limits.

Response:

The EPA prepared the Screening Assessment to identify potentially impactful industries and emissions unit types for further evaluation. Note that the Screening Assessment memorandum included the following language at the beginning of Section V:

> *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.*

In addition, the memorandum titled *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"* describes the proposed non-EGU applicability criteria and the relationship between those criteria and the Screening Assessment. This memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0191. Note that this memorandum included the following language:

> *The Screening Assessment was not intended to identify the specific emissions units subject to the proposed emissions standards under the proposed applicability criteria described above. Rather, the Screening Assessment 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.*

As stated, the primary purpose of the Screening Assessment was to identify potentially impactful industries and emissions unit types for further evaluation. While the EPA has confidence in its identification of impactful industries (identified in Step 1 of the analytical framework presented in the Screening Assessment), the proxy estimates for emissions unit types, emissions reductions, and costs from the 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 Reasonably Available Control Technology (RACT) rules,[14] NSPS, National Emissions Standards for Hazardous Air Pollutants (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. This review is detailed in the Proposed Non-EGU Sectors TSD available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145. (The updated version of this TSD to inform the final rule is also available in the docket.)

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 data used to inform the Screening Assessment using information from CoST and the CMDB indicated a "knee in the curve" at $7,500/ton. Substantial additional emissions reduction became available approaching that cost/ton, and leveled off after that value. This was an entirely reasonable basis on which to further investigate the emissions control technologies and strategies available up to that dollar per ton value, and it is entirely consistent with how the EPA has evaluated cost-effectiveness in prior transport actions. *See*, *e.g.*, 81 FR at 74550; 70 FR at 25204. Thus, the $7,500 marginal cost/ton threshold reflected in the 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. Further, the EPA proposed, and is finalizing, an emissions control stringency for EGUs that extends up to a representative average cost-per-ton level of $11,000. Thus, proposing non-EGU emissions control strategies up to $7,500 was generally commensurate with the requirements being considered for EGUs.

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 non-EGU industries covered in the final rule. 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* (hereinafter "Final Rule Technical Memorandum"), available in the docket. As explained in Section V.D.2 of the preamble, the updated analysis indicates that costs on a per-ton basis remain commensurate with the emissions control strategy for EGUs, and on a weighted-average basis are $5,339/ton. We explain further in that section of the preamble how this value encompasses a varying range of average costs for particular industries, but even for those non-EGU sources that may face

[14] Examples of state RACT rules and permitted emissions limits are includes in the *NO_X Permit Limits and RACT Tool* Excel workbook available in the docket here: EPA-HQ-OAR-2021-0668-DRAFT-30760.

the highest costs on a per-ton basis, those costs still remain commensurate with the highest-end costs-per-ton faced by EGU sources. As further explained in Section V of the preamble, the EPA's determination of an appropriate level of emissions-control stringency at Step 3 is informed by a multifactor analysis and is not strictly based on a determination of a single cost-effectiveness value.

To commenters who state that the EPA has not explained why we used a higher cost per ton threshold in the Screening Assessment than was used in the Revised CSAPR Update, we disagree. The $7,500 marginal cost/ton threshold was used because that is where the data evaluated in the Screening Assessment indicated a "knee in the curve" exists. Further, the Revised Cross-State Air Pollution Rule Update assessed significant contribution for the less protective 2008 ozone NAAQS, and it is not unreasonable in assessing significant contribution associated with the more protective 2015 ozone NAAQS, that a larger and potentially more costly universe of emissions controls and related potential reductions should be included in the Screening Assessment.

The cost figures used to inform the final Step 3 analysis did not include costs associated with monitoring, reporting, and recordkeeping. This is consistent with the cost presentation for EGUs at Step 3. And it is not necessary for purposes of Step 3 analysis that all such costs such as these should be included. Again, the purpose is not to precisely determine exactly how much regulated sources will need to spend on compliance, but to present representative cost figures associated with particular emissions control technologies and strategies to compare and evaluate what level of emissions reduction should be deemed necessary to eliminate "significant contribution."

2.2.5 Comments that Facilities are Already Well-Controlled

Comment:

Commenter (0295) remarks that the Mohave Desert AQMD has facilities within its jurisdiction in the Pipeline Transportation of Natural Gas and the Cement and Cement Product Manufacturing sectors which are considered for additional regulation under the proposed FIP. The commenter notes that all of these facilities are currently regulated by the MDAQMD and have, at the minimum, RACT, BACT, or BARCT already installed. Historically, the commenter has found that controls/requirements added to facilities already equipped with RACT, BACT or BARCT does not gain the emissions reductions estimated by the EPA. The commenter is concerned that without a robust analysis of the situation unique to each potentially affected facility, the estimated emissions reductions as expressed in the proposed FIP would not be realized.

Commenter (0278) states that it has identified multiple cement kilns that are subject to consent decrees that were not excluded from the non-EGU screening assessment. According to the commenter, the screening assessment takes credit for emissions reductions from several kilns that should not be a part of the good neighbor FIP evaluation. The commenter adds that there are only two cement plants in California that do not currently have SNCR installed and are not subject to consent decrees already requiring the installation of SNCR. However, the commenter states that the non-EGU screening assessment incorrectly accounts for emissions reductions from kilns that have installed SNCR for reasons outside of the proposed good neighbor FIP. Further, the commenter relates that as a result of the EPA's failure to exclude all kilns subject to consent decrees and incorrectly identifying existing NOx controls in place, NOx reductions in California alone were overestimated by 1,168 tons per year when removing the assumed reductions from CalPortland's Oro Grande facility and the Redding, CA facility, which are either under a consent decree or already have SNCR.

Commenter (0516) says that there are many more cement plants under a consent decree that the EPA did not eliminate from its analysis, which is evidence that the EPA did not conduct sufficient due diligence in determining the estimated amount of NOx emissions reductions that could be achieved through this proposed rule. The commenter adds that with cement kilns having over 50 years of regulation by the EPA, a review of the Title V permits could have easily identified the NOx emissions limits and control technologies in place. The commenter states that the EPA also incorrectly assumed that none of the kilns screened had already installed SNCR NOx emissions controls and that it could impose feasible NOx emissions standards via kiln-type and source cap limits. The commenter relays that three-quarters of the screened kilns already operate SNCR. The commenter also remarks that the EPA assumed kilns would get 50 percent NOx reductions from SNCR, whereas the EPA Cost of Control Manual reports a median reduction of 40 percent compared to no control. The commenter adds that extensive analysis will be needed to determine an accurate estimate of the amount of the NOx emissions reductions that would be expected from kilns currently without SNCR due to the technical factors unique to each kiln. The commenter asserts that the EPA must perform the industry screening exercise using corrected data to determine if the cement industry should be considered a Tier 1 or Tier 2 industry. Then, according to the commenter, the EPA should work with the PCA and its members to develop a menu of technically and economically feasible options for the industry to implement to reduce NOx emissions and address ozone transport.

Commenter (0545) states the EPA estimates that the proposal will necessitate NOX emissions reductions at eight Wisconsin sources, including six pulp/paper mills and two glass product manufacturing facilities. However, because the EPA is relying on 2019 data, its estimates are woefully out of date. The operator of three other “Tier 2” paper mills identified by the EPA has indicated to Wisconsin Manufacturers & Commerce (WMC) that the model fails to consider key programs being implemented at its facilities that will greatly reduce NOX emissions compared to 2019 levels. Another impacted manufacturer operates two “Tier 1” flat glass plants in Wisconsin. The company reported to WMC that since 2019 it has equipped these facilities with Selective Catalytic Reduction (SCR) control systems, and thus these estimates do not reflect current NOX emissions at these facilities.

Response:

As indicated in the Screening Assessment, the EPA included all emissions units with greater than 100 tpy emissions in the impactful industry identification (Screening Assessment at 3). Using the best information available to the EPA, Table A-3 in the Screening Assessment memorandum indicated the Cement and Concrete Product Manufacturing industry had 84 units with >100 tpy NOx emissions and those units were all included in the impactful industry part of the assessment. The next steps in the Screening Assessment were to establish a cost threshold and prepare the proxy results for 2026. The proxy results indicate that the EPA further analyzed 47 kilns at 38 cement manufacturing facilities in the 23 affected states at proposal.

The commenter claims that "there are many more cement plants under a consent decree that the EPA did not eliminate from its analysis, which is evidence that the EPA did not conduct sufficient due diligence in determining the estimated amount of NOx emissions reductions that could be achieved through this proposed rule." Commenter (0516) also attached their Exhibit A, which it stated showed that 36 of the 47 kilns already have SNCR installed.

The EPA used 2019 emissions inventory data provided by state/local/tribal authorities to prepare the Screening Assessment. In conducting the Screening Assessment, the EPA removed some sources from the analysis where we had information establishing that there was no additional emissions control opportunity at a source (either because controls exceeded the cost/ton threshold or because we had specific information about controls installed), before summarizing the Screening Assessment proxy results. *See* Screening Assessment Appendix B. Commenter (0516)'s Exhibit A did not identify the enforceable requirements by which the 36 kilns it states already have SNCR are required to operate that control, nor did it identify any associated emissions limits or other control requirements. The commenter likewise did not identify the source of information by which it concludes these kilns already have SNCR installed. We also note that commenter separately stated that the EPA's Screening Assessment had failed to identify or analyze 16 kilns at 13 facilities. (See Section 2.2.6 below (Comments About the Undercount of Facilities).)

We acknowledge that some of the data used for the Screening Assessment may be imperfect, but the purpose of the exercise was to focus attention on potential cost-effective emissions control opportunities at impactful industries with the ultimate objective of requiring sources to maintain a reasonable level of emissions performance. The commenter misunderstands the nature of this analysis as suggesting that the EPA would require some additional amount of emissions reduction from sources that are already equipped with the control technology identified in this final rule. But this is not correct; if a cement kiln is already equipped with SNCR and meeting the applicable emissions limit finalized in this rule, the rule does not require greater emissions reductions than are already being achieved.

Commenter (0516) also states that the EPA assumed emissions growth from this sector despite its claim that emissions have trended downward since 2016. This appears to be in reference to the EPA's emissions inventory methodology at Step 2 of the 4-step interstate transport framework, which reflects a different methodology and purpose than the Screening Assessment. In the Screening Assessment, the EPA explained that it did not forecast emissions growth but rather used actual data from 2019. *See* Screening Assessment at 6, n. 21.

We maintain that the Cement and Concrete Product Manufacturing Industry should be treated as an impactful industry, even acknowledging imperfections in the data available for the Screening Assessment. The analysis in Table A-3 indicated that there were potentially controllable emissions of up to 36,244 ozone season tons. These emissions, if not already controlled or reduced through enforceable and permanent emissions control requirements, are shown to have widespread air quality impacts, *see id.* The fact that certain cement kilns (or any other non-EGU sources that are subject to this rule) may already be well controlled is not justification to not bring other sources in this industry up to a similar level of emissions-control performance to eliminate their own significant contribution. As we explained in Section VI.C.2 of the preamble,

> [W]e 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.

Using information provided in the public comments, the EPA has updated information on existing controls at cement kilns for the final rule and re-estimated the number of cement kilns that may need to install controls, along with updated estimates for emissions reductions and costs. In the Final Rule Technical Memorandum, we estimate 2,573 tons of ozone season NOX emissions reductions are available from cement kilns at an average cost-effectiveness value of $1,632/ton, *see* Tables 6 & 7. These are highly cost-effective emissions reductions compared to other cost-per-ton estimates for EGUs and other non-EGU industries. Further, with respect to commenters' statements that kilns in California are not worth controlling, we note that 1,135 tons of ozone season NOx reductions are estimated from several cement kilns located in California, *see* Table 9. These have a cost-effectiveness value of $1,279/ton – *i.e.*, again, relatively highly cost-effective emissions reductions. We note that reductions from California's cement kilns represent a little less than half of the total ozone season NOx reductions available from this industry, *see id.* Table 8, and so it would not be reasonable to discount these potential emissions reduction opportunities from these sources in California.

With respect to the comment regarding Wisconsin non-EGU sources, in the air quality analysis for the final rule, we conclude that Wisconsin is not linked to receptors in 2026, and is therefore not subject to non-EGU emissions control requirements in this action. However, we disagree that these 2019 emissions inventory data are "woefully out of date"; the use of data from this year was a reasonable and adequate method for identifying cost-effective emissions-reduction opportunities at non-EGU industry sources.

Comment:

Commenter (0343) states that the pulp and paper sector was identified in the proposed rule as a Tier 2 industry due to contributions greater than or equal to 0.01 ppb at 11 receptors. The commenter remarks that it performed an updated AQAT analysis that incorporates information on closed and misidentified units and current fuel use, and the results show that the pulp, paper and paperboard sector emissions would impact only 8 receptors at or above the 0.01 ppb threshold. The commenter asserts that this sector therefore does not meet the EPA's criteria for inclusion as a Tier 2 Industry.

Commenter (0437) understands, based on the EPA's documentation of its analysis, that any units with NO_X emissions less than 100 tpy (*e.g.,* lime kilns, engines, and certain boilers) and any units without identified controls in the EPA's CoST model (*e.g.,* recovery furnaces) should have been removed from the AQAT analysis. The commenter highlights, the under the AQAT used to estimate sector-level impacts the pulp and paper sector was identified as a Tier 2 industry – having either (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, because EPA calculated contributions greater than or equal to 0.01 ppb at 11 downwind receptors.

Commenters (0343, 0437) claim that the AQAT analysis conducted by NCASI, with an updated unit list that incorporates information on closed and misidentified units and current fuel use, suggests that the pulp, paper and paperboard sector does not meet the EPA's criteria for inclusion as a Tier 2. The commenters clarify that by correcting the baseline inventory by removing non-operational boilers and those units inadvertently included in the analysis, results in a significant change in the number of critical receptors with impacts above the 0.01 ppb threshold and on the receptor with the maximum impact. This indicates that the pulp, paper, and paperboard sector no longer triggers the criteria identified for inclusion as a "Tier 2" industry. One commenter (0437) notes that the pulp and paper sector is only predicted to impact 8 receptors and the maximum impact is 0.0322 ppb at Galveston, TX. The commenters (0343, 0437) identify the following problems with the baseline unit inventory:

- Several of the units are at facilities that have been closed.
- Several of the units have been shut down.
- Unit ID 135113 has been identified as burning only biomass/wood waste.
- Unit ID 47545613 has been identified as burning only biomass/wood waste.
- Unit ID 16713213 (a lime kiln) is no longer operational.
- Unit ID 2791613 is a duplicate entry.
- Unit ID 47092413, Unit ID 47546113, Unit ID 17957213, Unit ID 33858313 and Unit ID 20389113 are five Kraft Recovery Furnaces that should have been removed when the unit list was developed.
- A number of units have ozone season emissions less than 41.7 tons per year.

Commenter (0343) adds that for those units identified as being outside the scope of the screening analysis, ozone season emissions were set to zero and the receptor ozone impacts were not calculated.

Response:

The EPA continues to find that the Screening Assessment reasonably and reliably identified Pulp, Paper, and Paperboard Mills as an impactful "Tier 2" industry. The EPA was unable to replicate the alternative screening assessment conducted by commenter or verify that this industry would have been removed under the Screening Assessment methodology using the commenter's information. Further, as explained in response to the comments above regarding cement kilns, these comments misunderstand the nature and purpose of the Screening Assessment. Even if some amount of the emissions identified as potentially controllable in the Screening Assessment are already being achieved, or such potentially controllable emissions cannot be feasibly controlled and are not being required in this final rule, that does not undermine the Agency's conclusions in the Screening Assessment regarding the potential impact of a given industry.

That said, the EPA evaluated these comments carefully. In their comments, the American Forest and Paper Association (AF&PA) provided several emissions unit IDs for emissions units (a) at facilities that they stated had closed, (b) that were duplicate entries, (c) that only burned biomass, or (d) that were recovery furnaces for which SCR application was not technically feasible. AF&PA removed these facilities/emissions units from the impactful industry assessment (Step 1 of the analytical framework in the Screening Assessment), re-estimated the emissions reductions and air quality impacts, and concluded that boilers from this industry should not be included in the final FIP.

The EPA did not receive documentation of federally enforceable terms requiring sources to shut down or evidence of surrendered permits during the public comment period or during stakeholder meetings following the comment period. The EPA attempted to verify facility and/or unit shutdowns by conducting online research or reviewing online permits. One example of a facility that potentially shutdown was Domtar Paper Co, LLC in Johnsburg, Pennsylvania, identified in appendices to Commenter's (0343) letter. The EPA found an active permit online for the facility.[15] Another example of a facility that Commenter (0437) indicated was shutdown is the Wisconsin Rapids Mill (Verso Corporation), in Wisconsin Rapids, Wisconsin. The EPA located a Title V Operating Permit renewal application dated February 10, 2021, that included the following content: *Verso Corporation (Verso) owns and operates a pulp and paper manufacturing facility in Wisconsin Rapids, Wood County, Wisconsin (Mill). The Mill currently operates under the Wisconsin Department of Natural Resources (WDNR) Title V Operating Permit (TVOP) No. 772010030—P12, which is due to expire on September 13, 2021. In accordance with s. NR 407.04(2), an application for renewal of the TVOP shall be submitted at least six months, and not more than 18 months, prior to its [sic] expiration date (i.e., by March 13, 2021). Note that the Mill shutdown operations in July 2020 for business reasons and it remains idled with no immediate plans to restart. Although the Mill is currently idled, Verso is submitting this TVOP renewal application in the event of a Mill restart.*[16] Commenter (0437) also indicated the following facilities were shutdown: PaperWorks Industries, Inc. in Wabash, Indiana,[17] Essity Operations Wausau, LLC, Middletown, Ohio,[18]

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[15]https://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/PermitDocuments/1306043[24-00009]_Issued_v3.pdf.

[16] https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html.

[17] https://permits.air.idem.in.gov/41556f.pdf.

[18] http://wwwapp.epa.ohio.gov/dapc/permits_issued/2002891.pdf.

and Georgia-Pacific Crossett, LLC in Crossett, Arkansas.[19] The EPA was not able to locate information to confirm that any of these facilities were shut down. The Final Rule Technical Memorandum indicates that boilers in this industry are estimated to account for an 1,836 ton reduction in ozone season NO_X emissions. This is the highest level of emissions reductions from boilers in any non-EGU industry covered by the rule. *See* Table 7.

Comment:

Commenter (0760) states that the EPA failed to consider that Facility-Wide Averaging is a NOx control measure allowed under LAC 33:III.2201. The commenter relates that the EPA indicated in its non-EGU Screening Assessment that many non-EGUs in Louisiana were not subject to NOx controls, and therefore imposed the requirement to add additional controls. The commenter conveys that this ignores the fact that LAC 33:III.2201, the NOx control requirement for the Baton Rouge Area and surrounding Region of Influence, allows for such averaging to more cost-effectively implement NOx reductions. The commenter adds that this rule is part of the Louisiana approved SIP, and the EPA must consider sources subject to a Facility-Wide Averaging Plan to be controlled for NOx during the ozone season and not subject to further control under the proposed FIP. Thus, the commenter requests that the EPA specifically provide in any final FIP that the provisions of the FIP do not apply to a unit subject to a Facility-Wide averaging plan approved pursuant to LAC 33:III.2201.E.

Response:

The commenter apparently is arguing that even if certain sources in Louisiana do not currently have emissions controls, they should nonetheless be treated as having controls and therefore removed from the Screening Assessment because they are subject to a state-level emissions control strategy that allows for averaging. The EPA disagrees that this would be appropriate in light of the purpose and methodology of the Screening Assessment. The EPA used the 2019 emissions inventory with information reported by state/local/tribal authorities, and commenter does not allege that this information is inaccurate with respect to these sources. Further, even if a source may be in compliance with state law through its inclusion in an emissions averaging plan, if that source meets the criteria for having available additional emissions reduction potential as estimated in the Screening Assessment, its compliance with that other program is not relevant to addressing interstate transport for the 2015 ozone NAAQS.

2.2.6 Comments about Undercounting of Facilities

Comments:

Commenter (0266) states that because the EPA did not provide a list of specific non-EGU sources that would be subject to the FIP in the proposal, the commenter finds it difficult to determine the subject sources in the commenter's state based upon the applicability criteria

[19] https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0597-AOP-R25.pdf.

provided in the proposed rule. The commenter notes that the EPA appears to have relied on a list of sources in a screening analysis to conduct the regulatory impact assessment, but the list does not appear to include all of the sources that would be subject based on the proposed rule's applicability criteria. The commenter states that this could lead to under-predicting the marginal costs associated with compliance and therefore over-regulating sources under this FIP.

Commenter (0516) states that the EPA is using incorrect and flawed data to justify further regulation of cement facilities. The commenter claims that in its screening assessment, the EPA did not screen all cement manufacturing facilities in the 23 affected states that the proposed rule would impact. The EPA included 47 kilns at 38 cement manufacturing facilities in the 23 affected states but did not include 16 kilns at 13 facilities (not including the 5 kilns removed from the screening assessment due to a consent decree or imminent replacement). The commenter asserts that the EPA should have evaluated every cement manufacturing facility in the 23 affected states to determine whether the cement industry should be designated as a Tier 1 Industry and thus subject to regulation under CSAPR. The commenter asserts that the EPA must perform the industry screening exercise using corrected data to determine if the cement industry should be considered a Tier 1 or Tier 2 industry. Then, according to the commenter, the EPA should work with the PCA and its members to develop a menu of technically and economically feasible options for the industry to implement to reduce NOx emissions and address ozone transport.

Commenter (0324) states there are several industrial coal boilers in Wisconsin over 100 MMBtu/hr design capacity and emitting over 100 tons/year NOx in 2019 that the EPA did not include on its list of 489 units for which the EPA estimated NOx reductions to be needed starting in 2026:

- Ahlstrom-Munksjo Kaukauna mill (Facility ID 445031180) – Boiler B09
- Ahlstrom-Munksjo Mosinee mill (Facility ID 737009570) – Boiler B24
- Georgia-Pacific – Green Bay Broadway Mill (Facility ID 405032870) – Boiler B26
- Global Equipment International, LLC (Facility ID 851009390) – Boiler B24

Commenter (0324) continues, based on these units' operation in 2019, it is unclear why the EPA did not include them in its list of units likely needing emissions reductions by 2026. The EPA should account for the emissions reductions and associated costs for these units in its analyses for the final rule unless the EPA can demonstrate further why they were not included in the proposal. The commenter argues otherwise, if the EPA's modeling assessment determined that the impact of these boilers on ozone transport is of a de minimis amount, then the EPA should state that is why these boilers are not included and assure they are not impacted by the rule.

Commenter (0344) contends that, because the data used in the EPA's modeling is incomplete and erroneous, the impacts from the proposed rule as written won't be as significant or as cost-effective as the EPA projects. The commenter states that this is problematic because Indiana must rely on the federal rule to fulfill its good neighbor obligations.

Commenter (0380) says that the 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). The commenter states that they alone operate over 260 RICE that would be subject to the proposed rule.

Commenter (0397) states that the proposed FIP underestimates Oklahoma facilities that would be subject to it, underestimates the NOx emissions reductions, and would result in overcontrol of NOx emissions if finalized as proposed. The commenter relates that the EPA identified non-EGU point sources and the expected ozone-season NOx emissions reductions that may be expected if the units installed the controls required in the proposed FIP. According to the commenter, the EPA's selection of industry categories appears circular because EPA narrowed the analyzed non-EGU industries in its proposed FIP and related screening memorandum in part by assuming what sources "could be better controlled at a reasonable cost." The commenter asserts that this apparent exclusion of certain industries from the analysis biases the results because it fails to consider all non-EGU sources in the same analysis. The commenter performed a screening analysis and found different numbers of units in the three source categories the EPA identified for Oklahoma, for example 73 engines compared to the EPA's estimate of 32 engines. Further, the commenter identifies some units in the other industry categories that would likely be subject to the proposed FIP if finalized in its current form. The commenter is particularly concerned about the proposed limits and new control requirements for compressor engines in natural gas service. Based on the description of the screening approach and the reference to the NAICS code for engines in transmissions service (NAICS 4862, Pipeline Transportation of Natural Gas), the commenter's staff initially focused only on compressor engines downstream from natural gas liquids extraction facilities or, where there was no natural gas plant between the well field and the transmission pipeline, those pipelines regulated by the FERC. However, after reviewing the applicability criteria and the proposed definition of "pipeline transportation of natural gas," the commenter's staff concluded that any compressor engine over 1,000 hp would likely be subject to the requirements of the proposed FIP. Based on this interpretation of the applicability criteria, the commenter identifies a significantly larger number of compressor engines that would be potentially subject to the proposed FIP and higher emissions reductions than were identified by the EPA. The commenter's staff are confident that the proposed FIP would substantially and unnecessarily over-control emissions from Oklahoma sources beyond the requirement to address downwind nonattainment or maintenance concerns. The commenter encourages the EPA to engage with the commenter to discuss the approvability of the Oklahoma ozone transport SIP or to adjust the proposed FIP requirements that would be applicable to Oklahoma to ensure there is no over-control.

Response:

The EPA recognizes that the Screening Assessment may not have captured all sources that could be subject to regulation under the applicability criteria of the final rule; however, this does not alter the identification of impactful industries. In fact, to the extent emissions units were missed in the Screening Assessment, this reinforces that emissions reductions from these industries would improve downwind ozone levels. The basis for the final rule's applicability criteria and emissions-control requirements are addressed in Section VI.C of the preamble and the Final Non-EGU Sectors TSD, and comments on these topics are addressed in Section 2.3, and Chapters 4 and 5 of this document.

Commenters state that if there are more units that would be subject to the final rule than are identified in the Screening Assessment, this would mean the cost of the rule would be higher and therefore potentially not justified. However, the EPA's Step 3 analysis focuses on cost-effectiveness in terms of average cost per ton of emissions reduced, as part of a multifactor analysis to identify an appropriate level of stringency. Thus, for example, in the Final Rule Technical Memorandum, we have updated the estimate of the number of units that could be affected in the Pipeline Transportation of Natural Gas industry, and we estimate there may be around 905 units, *see* Table 5. The estimated total costs for this industry are $385,463,197 annually in 2026, and the resulting estimated ozone season emissions reductions are 32,247 tons—the largest amount of estimated emissions reductions of any non-EGU industry in this rule. The representative average cost/ton value for this industry is $4,981/ton—relatively highly cost effective in comparison to the full range of cost-effectiveness estimates for the final rule. *See* Table 6.

Commenters state that without a more complete analysis of the universe of sources covered by the rule, we may not have an accurate depiction of representative cost estimates in the Screening Assessment. But these comments lack reasonable specificity that this would be the case, *i.e.*, to the extent there are additional units not covered by the Screening Assessment's methodology, commenters have not offered evidence that the effect was unidirectionally towards an under-prediction of costs on a per-ton basis. Some units may have higher or lower costs than the representative values used in the Screening Assessment, an observation the Screening Assessment readily acknowledged. Nonetheless, the final rule's applicability criteria and other requirements reflect adjustments for the rule to be cost-reasonable and reflect potentially larger sets of covered units. For example, Section VI.C.1 of the preamble discusses the Facility-Wide Averaging Plan option that we are making available for the Pipeline Transportation of Natural Gas industry, in recognition of the relatively large number of individual emissions units that are covered in that industry and to focus efforts on obtaining the most cost-effective emissions reductions.

Commenters also state that without a more accurate understanding of the number of sources that would be covered, the rule risks overcontrolling in relation to the interstate transport problems being addressed. The final record demonstrates that this is not the case. The Final Rule Technical Memorandum reflects updates in non-EGU data, including total estimated emissions reductions by industry and by state. We then applied this information in conducting our air quality analysis and overcontrol assessment. As explained in Section V.D.4 of the preamble, even accounting for this updated estimate of the number of sources and emissions reductions that would be achieved from the covered non-EGU industries, the rule does not result in prohibited overcontrol.

2.2.7 Comments Regarding Infeasibility of Emissions Reductions

Comments:

Commenters (0320, 0359) state that the EPA did not perform a quality analysis of control feasibility and potential NOx emissions reductions.

Commenter (0516) notes that for some kilns, SNCR is not feasible to install due to the kiln type and design, and the EPA should work with the Portland Cement Association's (PCA's) members to identify potential alternative controls for these cases. The commenter suggests that another method for potential additional NOx reductions is injecting additional ammonia in an SNCR system, and the commenter suggests that the EPA work with PCA and its members to explore the feasibility of increasing ammonia injection without resulting in ammonia slip.

Commenter (0437) states that the EPA has overestimated the control efficiency and underestimated the cost of controls as they apply to pulp and paper mill boilers, and as a result, the EPA is overly optimistic about the cost-effectiveness of NOx controls for these units. For support, the commenter performed an analysis that shows that application of NOx controls to a majority of the pulp and paper boilers 1) will be difficult to implement, 2) will not achieve the emissions reductions the EPA has predicted, and/or 3) is not cost-effective based on the EPA's presumptive value of $7,500/ton.

Commenter (0300) states that the EPA should not include non-EGU emissions units in the FIP given the lack of a thorough evaluation of the feasibility of meeting any of the proposed emissions limitations for non-EGUs. According to the commenter, the EPA points out at least three times in the proposed rule that setting emissions limitations on non-EGUs is more complicated than for EGUs, yet the proposed FIP applies very arbitrary emissions limits to entire industrial sectors. The commenter also remarks that the EPA also applies a screening assessment on a few large emissions sources of NOx and assumes that add-on controls are technically feasible for both those sources and the entire realm of sources in that industrial sector with no detailed technical analysis. The commenter further remarks that the EPA uses methods that oversimplify the economics and fail to address the feasibility of installing control technologies to justify the proposed FIP for non-EGU sources. The commenter states that the EPA should reconsider including non-EGU emissions units entirely or narrow the scope of such regulation to the facility-specific emissions units actually evaluated. The commenter recommends that if the EPA narrows the scope to facility-specific emissions units, it should determine an appropriate level of NOx reduction for each unit, including a realistic evaluation of the technical and economic feasibility for NOx control for each. Otherwise, the commenter suggests that some form of cap-and-trade program should be contemplated to allow for flexibility and practical options for reducing NOx emissions.

Commenter (0764) states that site-specific applicability and emissions reduction assessments actually must be site-specific. According to the commenter, the EPA admits that the proposed rule did not include any unit-specific feasibility analyses, yet nonetheless imposes limits that expressly presuppose such feasibility. According to the commenter, the EPA admits the non-EGU screening assessment "is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs," yet, the EPA proposes to blanketly regulate all emissions units across entire industry sectors.

Response:

In general, the requirements that the EPA is finalizing for non-EGU industry sources in this rule are cost-effective and feasible, as explained in Section V of the preamble. Section VI of the preamble explains adjustments the EPA has made in the final rule to ensure implementation of these requirements is feasible. Additional time to comply is available on a case-by-case basis, as is the availability of an alternative emissions limit in the case of extreme economic hardship.

The $7,500 marginal cost/ton threshold reflected in the analytical framework in the Screening Assessment was a relative cost/ton level to identify potential emissions-control opportunities for further evaluation. 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. As discussed in Section V.D.2 of the preamble, we acknowledge that there are a range of representative cost-per-ton estimates for the various non-EGU industries, as summarized in the Final Rule Technical Memorandum.

The Agency disagrees that site-specific engineering analysis is necessary before finalizing this rule. The emissions control requirements in this rule are based on widely adopted, well-understood NOx pollution-control techniques and technologies. While the Agency acknowledged that its Screening Assessment was not intended to function as a site-specific engineering analysis, this was not intended to suggest that the Screening Assessment was not reliable for its purpose in identifying where the Agency should focus its attention on obtaining cost-effective NO_X emissions reduction opportunities. See response to comments in Section 2.2.1 (General Criticism of Non-EGU Screening Assessment Methodology) for an overall review of the process by which the EPA ultimately derived the final rule non-EGU requirements.

Comment:

Commenter (0359) is concerned about the inclusion of the iron and steel mills and ferroalloy manufacturing industry and with the controls proposed for this industry. The commenter notes that the EPA does not currently regulate NOx emissions from this source category and has not provided a justification for including this source category in the proposed rule, nor has it provided adequate justification for the proposed emissions standards. The commenter states that the lack of proven technologies and data to establish proposed emissions limits for this source category is especially troubling considering that the EPA proposed emissions standards for 15 separate emissions units and assumed control reduction efficiencies. According to the commenter, the screening assessment did not consider that facilities within this industry have multiple combinations of emissions units to manufacture steel or ferroalloys when it estimated emissions reduction opportunities and related costs. The commenter adds that the cost per ozone season ton of NOx reductions averages $9,500 per ton and as high as $16,910 per ton for each emissions unit (not for the facility) according to the screening assessment. The commenter says that considering facilities in this industry have over 25 emissions units per facility, the cost of these non-technically demonstrated proposed emissions limits are exorbitant for one emissions unit, let alone for the entire facility to attempt to comply. The commenter asserts that the EPA did not address the costs on a per facility basis when it proposed 15 possible types of emissions units within each facility.

Commenter (0504) asserts that the EPA's assessment of NOx emissions reduction potential from "known controls" at EAF steel producers is erroneous and unsupported. The commenter states that although the EPA used CoST data to identify NOx emissions reductions available through "known controls," this parameter does not consider whether the controls are known to be used in any particular industry sector or for any specific emissions unit. According to the commenter, the non-EGU screening assessment does not explain how the EPA identified the five control strategies it believed could be used in the iron and steel sector, but the EPA nonetheless concluded that these five control strategies could reduce ozone season NOx emissions from 39 emissions units at "iron and steel" facilities in the upwind states for up to $7,500 CPT. The commenter relates that of the 39 greater than 100 tpy emissions units in the "iron and steel" sector that the EPA linked to downwind receptors, the EPA identified only three units at EAF steel producers for which there were NOx controls at or below the $7,500 CPT threshold. One of these is a 19 tpy emissions unit at Nucor's facility in Blytheville, Arkansas (identified as "Industrial Processes – Other Not Classified."). According to the commenter, given this vague description, the commenter has no way of identifying this emissions unit or knowing how the EPA determined that the use of "Low NOx Burners and Flue Gas Recirculation" would allow this source to reduce its ozone season emissions by 6 tpy. The commenter stated that the Title V permit for Nucor Blytheville does not identify any 19 tpy NOx sources, and if that unit is any of the various furnaces identified in the permit, the NOx emissions reduction potential is misstated because each furnace already utilizes low NOx burners. The commenter claims that the other two emissions units also appear to be misidentified. The commenter related that the non-EGU screening assessment identifies both of these emissions units as operated by Chaparral Virginia Incorporated in Dinwiddie, Virginia, with one of these emissions units as "Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation," despite the facility operating an EAF, and not a blast furnace. According to the commenter, the EPA identifies the other unit only as "Boilers - > 100 Million BTU/hr," but the EPA concludes NO_X from both of these emissions units can be reduced by 90 percent using SCR. The commenter noted that SCR has never been used on an EAF and cannot be feasibly used to control NO_X emissions from an EAF. The commenter adds that even if SCR were technologically feasible for either of these units, it is unrealistic to conclude that SCR could reduce NOx emissions from these sources by 90 percent for less than $7,500 per ton. The commenter adds that the modeling input files place two of these units at the Nucor Blytheville facility and only one at the Chaparral facility, which is the opposite of what is in the non-EGU screening assessment. In short, the EPA misconstrued every single emissions unit attributed to an EAF steel producer. The commenter asserts that the data set the EPA utilized in determining that EAF steel producers in 23 states should be subject to unprecedented NOx limits is shockingly small (3 units at 2 facilities) and 100 percent incorrect. According to the commenter, the EPA cannot, and should not, base any findings or regulatory requirements on such scant, erroneous, and inconsistent data.

Response:

The EPA is not finalizing emissions limits related to blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and EAFs as proposed. The only emissions units within Iron and Steel Mills and Ferroalloy Manufacturing that the EPA is finalizing requirements for are reheat furnaces and boilers. These comments are further responded to in Section VI.C.3 of the preamble and in the Final Non-EGU Sectors TSD. Note that these comments regarding the alleged infeasibility of certain types of emissions controls on certain types of units in the Iron and Steel Mills and Ferroalloy Manufacturing industry do not undermine the Agency's conclusions in the Screening Assessment that this is an impactful industry nor that those emissions reductions that the Agency concludes are feasible and cost-effective (*i.e.*, at reheat furnaces and boilers in this industry) are not appropriate to require as part of the rule's overall strategy to eliminate significant contribution for the 2015 ozone NAAQS.

2.2.8 Analysis of Municipal Waste Combustion (MWC) Facilities

Comments:

Commenter (0757) asserts that the EPA's rule must not arbitrarily fail to regulate MWCs. The commenter contends that the EPA's failure to include limits for MWCs in its proposed rule is the result of the arbitrary exclusion of MWCs from its screening analysis of non-EGUs, and the final rule must assess and regulate incinerator emissions. The commenter explains that the EPA's threshold criteria for considering a non-EGU industry sector in its Screening Assessment is that the sector includes emissions units that emit over 100 tpy of NOx and that these are uncontrolled sources or sources that could be better controlled at a reasonable cost. According to the commenter, incinerators meet both these criteria, noting that over 90 percent of the incinerators in transport states emit over 100 tpy of NOx, with a per-facility average of 473 tpy of emissions. The commenter also relates that the proposed rule cites findings by the OTC that incinerators could be better controlled at costs well within the proposed rule's cost effectiveness threshold. The commenter states that the EPA excludes this from the assessment and provides no explanation of why. According to the commenter, to the extent that the footnote suggests that the EPA does not consider incinerators to be "non-EGUs" because many of them do produce electricity, that is no rationale, given that the EPA expressly excludes incinerators from its regulation of EGUs. The commenter remarks that the EPA's exclusion of incinerators from the Screening Assessment and from proposed regulation is particularly arbitrary given that incinerators emit more NOx than nearly all of the 41 other non-EGU industries that the EPA did screen and consider. The commenter concludes that it is arbitrary for the EPA to fail to propose MWC emissions limits when it did propose limits on industries with much less NOx impact, and the EPA must rectify this by including incinerator limits in the final rule.

The commenter (0318) encourages the EPA to include municipal waste combustors in the final FIP, which a recent analysis by the commenter indicates can achieve large reductions in NOx emissions below the $7,500/ton cost threshold used with the other non-EGU source sectors.

Commenters (0757, 0758) consider it imperative that the EPA require NOx reduction from MWCs, including small MWCs where they can feasibly meet the emissions limits. Commenter (0758) states that these facilities emit high amounts of NOx, even more than coal plants per unit of energy generated, and can achieve far lower NOx limits than those most facilities are currently subject to. The commenter adds that MWCs are often located in EJ communities and that large MWCs already have continuous emissions monitors, which reduces one aspect of the cost of compliance with new standards. The commenter also remarks that the EPA should have included MWCs in its screening assessment, since it meets both assessment criteria of having over 100 tpy of NOx emissions and could be better controlled at a reasonable cost.

Commenters (0757, 0758) assert that the EPA should establish a MWC NOx limit measured on an averaging period of 24 hours or shorter, which will help to reduce the likelihood that MWC NOx emissions will contribute to a spike in ozone. The commenters also assert that the EPA should set a 24-hour NOx emissions limit of 50 parts per million dry volume @ seven percent O2 ("ppm") for MWCs based on SCR technology, which is the technology needed to ensure this high-emitting sector stops contributing to downwind ozone pollution. According to the commenters, SCR is a widely available technology that, as the proposed rule notes, already is in use in 60 percent of the coal fleet and has been considered Best Available Control Technology (BACT) for decades. The commenters adds that the Ozone Transport Commission's (OTC's) revised Municipal Waste Combustor Workgroup Report notes one facility uses SCR and has a permitted emissions limit of 50 ppm, and analyses of installing SCR at three other existing MWCs also assumed emissions rates of 50 ppm. The commenters further note that this report presents results from third-party studies of SCR installation and use costs of $10,296/ton to $12,779/ton (Wheelabrator Baltimore), $15,898/ton (Covanta Fairfax), and $31,445/ton (Covanta Alexandria/Arlington), and also mentions that the lowest estimate is most analogous the $11,000/ton weighted-average cost for new SCRs for coal units that the EPA finds acceptable in the proposed rule. The commenters request that the EPA ask for information to verify this lowest estimate, as it appears to depend on the cost of operating the current control system on the incinerator. The commenters claim that SCR emissions controls are necessary to prevent interstate ozone transport. The commenters report that the EPA predicts that New Jersey will continue to significantly contribute to downwind receptors in 2026, yet the EPA requires no reductions from New Jersey's non-EGU sector and no reductions in the state's EGU emissions budget after 2023. The commenters recommend that the EPA look to reduce emissions from incinerators to eliminate New Jersey's significant contributions to interstate ozone. The commenters add that since all four of New Jersey's currently operating incinerators are already equipped with SNCR systems, and the two largest incinerators have additional low NOx systems, the EPA must go beyond the technology already in place and require SCR technology and a 50 ppm (24-hour) limit. The commenters assert that the EPA cannot discount SCR technology for incinerators based on the cost-effectiveness threshold for non-EGUs, since the threshold so did not consider cost estimates specific to the incinerator industry. The commenters note that the EPA has cautioned that being above this threshold is not on its own a justification for not requiring reductions beyond that point, the EPA has previously required controls that exceeded this threshold, and states subject to this Rule have their own cost-effectiveness thresholds of up to $18,983/ton NOx, which exceeds the SCR costs for incinerators. Alternatively, the commenters state 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. The commenters note that recent studies have shown that there are a variety of technologies that can help a wide range of MWC boiler types achieve this limit at costs that are significantly below the $7,500/ton cost effectiveness threshold in the EPA's proposed rule. The commenters note that there are at least nine facilities in Virginia and Maryland that can meet the 110-ppm limit using a patented Low NOx system, and while this technology will not work on some facilities, such as those using Aireal grate technology, those operating RFD units, and those with rotary combustor units, it may be possible to reach this limit with SNCR or other cost-efficient NOx controls.

Commenter (0798) asserts that it would be arbitrary for the EPA to not include waste incinerators in the rule if other non-EGUs are included. The commenter notes that the EPA's analysis shows that waste incinerator emissions can be an order of magnitude larger than the applicability limits the EPA is using for the other industries. The commenter claims that the lack of analysis of technical feasibility or cost effectiveness for this industry is not a reason to exclude it when other industries, such as the iron and steel industry also lack this analysis but are included. The commenter adds that if the EPA does include waste incinerators in the rule, it will need to perform a reanalysis of overcontrol, since including these units will require adjusting the limits at other facilities to reduce the overcontrol resulting from the proposed rule.

Commenter (0526) asserts that MSW facilities should not be included in the rule. The commenter agrees with the proposed rule that there is not a compelling reason to change the past practice of not including units smaller than 25 MW and not including MWCs and supports the continued exclusion of these facilities. The commenter adds that the benefits are quite small compared to the costs, and MWCs are tightly and more appropriately regulated elsewhere. Further, the commenter remarks that many of the MSW facilities potentially regulated under this proposed rule are well below the applicability threshold and may not have the systems in place to participate in trading programs, which would cause them to incur further costs. The commenter additionally notes that the benefits of MWCs should also be adequately accounted for in the analysis, which include offsets in fossil fuel electricity production emissions from the energy produced by MWCs, reductions in transportation emissions from the elimination of long-hauls to remote landfills, avoided landfill methane emissions, and the provision of critical solid waste management services, jobs, and other benefits for the communities where they operate.

Response:

In response to comments received, for the final rule the EPA evaluated whether as a non-EGU industry or emissions unit type MWCs would be considered an impactful industry/emissions unit. In a memorandum to the docket for the final rule titled *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* ("MWC Supplemental Memorandum") the EPA concluded that MWCs should be included in the final rule because the emissions reduction potential and cost effectiveness values for MWCs compare favorably with the non-EGU industries that were identified through the Screening Assessment methodology, and the EPA is finalizing emissions limits for certain MWC units in the rule.

Commenter’s assertion that MWCs should not be included on the basis that they do not typically have electricity generation capacity greater than 25 MW does not follow. While that size threshold has traditionally been used with respect to EGUs in transport rules (see Section V.B.3.b of the preamble), MWCs serve functions (, waste reduction/management) and have operating profiles that are different than EGUs; their purpose is not primarily the generation of electricity. The MWC Supplemental Memorandum demonstrates that, using the same methodology and data used in the Screening Assessment for other non-EGU industries, MWCs would qualify as a “Tier 1” industry. The Final Rule Technical Memorandum likewise demonstrates that the costs and emissions-reductions associated with the final rule requirements for MWCs compare favorably with other non-EGU industries covered in the rule.

2.3 Application of the Final Rule to EGU and Non-EGU Sources

2.3.1 EGU Applicability

Comment:

Commenter (0357) asserts that the EPA should exempt low-utilization gas turbines from the rule. According to the commenter, natural gas-fired combustion turbines are used to supply electricity primarily during periods of peak demand to reduce the electrical load and provide backup services during system outages. The commenter notes that these units typically operate less than 100 hours per year, and in most cases far less frequently. The commenter also notes that the operating permits for these turbines include federally enforceable restrictions on PTE. The commenter further notes that these turbines are subject to the Acid Rain Program and associated monitoring provisions in 40 Code of Federal Regulations (CFR) part 75 and are qualified as low-mass emissions (LME) units as provided in 40 CFR 75.19 and each turbine is equipped with NOx emissions controls (either water injection or SCR). The commenter states that while LME units have several options to demonstrate ongoing compliance, the commenter uses the default emissions factors in 40 CFR 75.19 for reporting purposes, but the proposed rule does not appear to take LME units into account when allocating allowances based on a presumptive level of NOx control. For example, according to the commenter, at the 2026 presumptive control level of 0.03 lb. NOx / MMBtu, turbines would be allocated 5 times fewer allowances as a result of using the default emissions factor in 75.19 Table LM-2. The commenter states that it would have to purchase additional allowances, perform emissions testing to develop a fuel-and-unit-specific emissions factor, or install a continuous emissions monitoring system. According to the commenter, none of these expenses are justified for low utilization LME units. The commenter also remarks that the “generation shifting” in the IPM modeling for future years 2023 and 2026 fail to account for low-utilization natural gas-fired peaking units. As an example, the commenter says the 2026 model projections “shift” additional operations to two of its facilities, which results in these units generating 3-15 times more electricity relative to the 2021 baseline year. The commenter claims that this is not possible due to regulatory constraints, as both are LME units and operating at the EPA’s projected levels would result in the loss of LME status and potential permit violations. The commenter declares that the possible impacts resulting from the proposed shift are not only unreasonable, but also fail to demonstrate that the EPA considered the existing regulatory framework and operation of such units in its proposed rule. The commenter adds that the EPA already receives emissions and operational data from low utilization LME units, which demonstrate that these units have a de minimis impact on state-wide emissions on an ozone season basis. The commenter also states that these units are already controlled, and further emissions reductions are cost prohibitive. For instance, according to the commenter, equipping a 32 MW gas turbine that emits 11 tons NOx per year with an SCR system with an 80 percent reduction efficiency would result in a $607,272 cost per ton of NOx removed (assuming a $167/kW retrofit cost for SCR based on the EPA's Control Cost Manual).

Commenter (0357) asserts that EGUs under 25 MW should continue to be excluded from the rule. According to the commenter, the EPA rationale for the exclusion is sound, concluding that regulating such sources is not warranted due to the low potential reductions, relatively high cost per ton of reduction and high monitoring and other compliance burdens that would ensue. The commenter notes that small units are generally limited in operation and have a low contribution to heat input during the ozone season as well as low total NOx emissions. The commenter notes that many of these small units have permit terms restricting operation to no more than 10 percent of a unit's annual heat input capacity and actual operating hours fall well below this limitation. In addition, according to the commenter, it is not technically feasible to retrofit boilers that operate intermittently with end of pipe controls like SCR that require steady-state conditions and operating temperatures. The commenter states that adding SCR NOx controls to intermittently operated boilers with low utilization would also be overly burdensome for minimal emissions reductions. The commenter adds that many small units are already adequately equipped with emissions controls and adding additional or different emissions controls would not be cost effective. The commenter provides an example of a diesel peaking fleet with annual emissions of approximately 1 ton of NOx per year. The commenter notes that at a control cost of $180,000 for installation of a SCR (from the EPA Control Cost Manual for a new unit), installing controls on a single unit would cost $225,000 per ton of NOx at an 80 percent control level.

Response:

In regard to comments on LME EGUs that are covered by the proposal, the EPA notes any such units included in this rule are consistent with coverage under prior CSAPR programs. The EPA does not identify any additional mitigation strategy from these sources but recognizes that within this EGU segment there may be reductions available at cost levels lower than the price at which allowances may be trading, and so the trading program would therefore tend to incentivize such reductions. The EPA does not use a presumptive rate for allocating allowances to these units, but rather uses their reported historical operating data, heat input, and emissions levels.

Consistent with the comment, the EPA is not changing its applicability criteria to include EGUs less than 25 MW, see Section V.B.3.b of the preamble. As discussed in preamble Section V.B.1.f of the preamble, the EPA is not estimating emissions reductions commensurate with generation shifting in the final rule, rendering the above comments on the topic moot.

Comment:

Commenter (0322) recommends that units be exempt from the rule or that there be unit-specific allocations that support operation of units that agree to retirement.

Response:

This comment appears to be in relation to the EGU emissions control strategy of the rule. See preamble Section VI.B.1.c and VI.B.4. In this final rule, any EGU retiring prior to 2030 would not face a daily backstop rate unless a SCR was already in place.

2.3.2 Non-EGU Applicability

Comment:

Commenter (0308) states that the applicability criteria between industrial categories needs to be consistent and concise. The commenter notes that it is particularly confusing as to whether the NAICS Codes are used to determine applicability. Specifically, according to the commenter, it is unclear whether an otherwise applicable emissions unit located at a facility whose primary NAICS Code is not identified in the rule is subject to the FIP.

Response:

If the commenter has an emissions unit type (*e.g.*, boiler) that is not in one of the industries identified in Table II.A-1 of the final rule preamble, the boiler is not subject to the final emissions limits. The basis for the final rule applicability criteria for non-EGUs is set forth in Section VI.C of the preamble and is further discussed in the Final Non-EGU Sectors TSD. These criteria generally are derived from existing requirements such as RACT or NSPS provisions, and allow for a clear, objective, and efficient determination of which units are subject to the requirements of the rule.

Comment:

Commenter (0437) suggests that when issuing its re-proposal (assuming that pulp and paper boilers are not excluded given that they do not meet the criteria laid out in the proposal), the EPA should clarify that the proposed standards are not intended to apply to pulp and paper recovery furnaces (sometimes referred to as recovery boilers). According to the commenter, a recovery furnace produces thermal energy in the form of steam, and the primary purpose of the furnace is to recover spent chemicals from the pulping process. The commenter relates that as documented by NCASI in the Technical Bulletin No. 1051, NOx control options are not readily available for recovery furnaces. According to the commenter, NCASI identified staged combustion using quaternary air ports at certain large furnaces as technically feasible, but noted that the industry has only limited, short-term experience with this technology and the impact on other pollutants such as sulfur dioxide, carbon monoxide, and reduced sulfur compounds is unknown. In addition, the commenter notes that some shorter furnaces cannot accommodate quaternary air ports because they do not have room to add a fourth level of air between the tertiary ports and the bull nose baffle arch of the furnace. The commenter also notes that a recovery furnace would not typically be considered a "coal-fired, residual oil-fired, distillate oil-fired," or a "natural gas-fired industrial boiler," these furnaces produce steam and commonly use either distillate oil, residual oil, or natural gas as auxiliary fuel for startup, shutdown, transient flame and operational stability, and occasionally to produce supplemental steam. Therefore, the commenter requests that if the EPA determines it is necessary to regulate non-EGU boilers, it should clearly state in the regulatory language that recovery furnaces are not subject to the standards proposed at 40 CFR 52.45.The commenter also states that the EPA should clarify that the proposed standards do not apply to biomass boilers, which commonly use either distillate oil, residual oil, or natural gas as supplemental or auxiliary fuel for startup, shutdown, and to ensure consistent and stable operations (*e.g.*, when biomass fuel moisture is high, or to safely combust process gases).

The commenter notes that NOx control technologies are not identified for biomass boilers in the EPA's CoST model and are not widely applied to biomass boilers in the pulp and paper manufacturing industry. The commenter believes it was the EPA's intent to exclude biomass boilers from this rule and asks that the EPA make that intent clear if pulp and paper boiler requirements are finalized. According to the commenter, the EPA should exclude limited-use and temporary boilers. The commenter states that these units operate a limited amount of time each year, generally limited by permit restrictions, their contribution to total NOx emissions is small, and the installation of controls would not be cost effective. The commenter notes that they spend more of their time in startup, shutdown, or other low-load operating conditions, which potentially affects the suitability and effectiveness of NOx controls on these units and makes emissions testing difficult. The commenter adds that temporary boilers are exempt from major federal regulatory requirements such as the Boiler MACT and the industrial boiler rules in 40 CFR part 60 and limited-use boilers are subject to only limited requirements under these rules.

Commenter (0549) recommends that the EPA expressly exempt some mixed fuel sources from the proposed FIP requirements (*e.g.*, by providing an express exclusion or excluding them from the definition of the source category) due to the technical infeasibility of emissions controls. The commenter relates that some boilers burn a mixture of natural gas and hydrogen/methane off-gas fuel from the plant fuel gas system or an on-site production process. According to the commenter, due to the presence of hydrogen in the off-gas and its naturally hotter temperature than natural gas, the combustion temperatures and NOx emissions are subsequently higher than those associated with natural gas combustion alone. The commenter asserts that the combustion of these off-gas streams is critically important to allow highly integrated chemical production facilities to continue to recover the heating value and create energy recovery through steam generation. The commenter also states that given their makeup, it can also be technically infeasible to run these types of units with a SCR control system since there is a high potential for some of the existing boilers' combustion products to interfere with the SCR catalysts. The commenter also provides examples of facilities which operate boilers that burns landfill gas and that burn hazardous waste. The commenter notes that these types of units already operate under other regulatory permit requirements that call for separate good maintenance and combustion practices as well as monitoring, testing, and reporting. The commenter also strongly recommends that the EPA include a definition for "natural gas" in section 52.45 or reference the earlier "natural gas" definition included in proposed 40 CFR 52.41 for the oil and gas natural gas transportation sector.

Commenter (0764) states that the EPA should at least include an exemption allowance for site-specific technical or economic issues (such as the exemption allowances commonly found in the EPA's New Source Performance Standards). The commenter states that the EPA gave no consideration in the proposed FIP to boilers that burn non-fossil fuels nor to boilers that experience varying loads, both of which apply to boilers in the pulp and paper industry and which the EPA has acknowledged it is infeasible to control. According to the commenter, another difference between EGU and industrial, commercial, and institutional (ICI) boilers is fuel diversity, where EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), and ICI boilers tend to be designed for and use a more diverse mix of fuels (*e.g.*, fuel by- products, waste, wood) in addition to the three conventional fuels above. The commenter contends that these differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of an air pollution control device applicability. Further, the commenter agrees with American Forest and Paper Association's (AF&PA) comments about the feasibility of controls, including low-NOx burners (LNBs), SCR, and SNCR for pulp & paper industry boilers and adopts AF&PA's comments about the EPA's short-sided review of RACT standards considered when establishing the proposed limits. The commenter states that the EPA does not recognize the various options based on boiler configurations, firing methods, and fuels provided by the referenced standards.

Response:

In the final rule, the EPA is including single-use fuel limits for non-EGU boilers using coal, residual oil, distillate oil, and natural gas. Specifically, boilers that burn 10 percent or more of fuels other than coal, residual or distillate oil, natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements contained within the final action. The EPA has clarified that the final rule will not cover recovery furnaces. Lastly, the final rule allows a facility owner to submit a request for a low use exemption that restricts the boiler from operating more than 10 percent of the year. If the EPA grants the request, the boiler will be excluded from the final FIP's requirements. For more details, see Section VI.C.5 of the final rule preamble. To the extent there are any remaining concerns about any boiler units' inability to comply with the final emissions limits, the final rule allows sources to apply for alternative limits based on a showing of extreme economic hardship, as more fully explained in Section VI.C. of the preamble.

Comments:

Commenter (0280) states that clarification of the applicability of emissions limitations and requirements is necessary. According to the commenter, the applicability and requirements for EAF operations is confusing and infers that each emissions unit that directly emits, or has the potential to emit, 100 tons per year or more of NOx is subject to the requirements. If that is the case, then the commenter agrees that only emissions units with the potential to emit more than 100 tons per year individually should be considered for potential air pollution controls. In contrast, if the EPA considers the 100 ton per year threshold to be for the entire EAF operation, then the commenter finds the EPA's interpretation inappropriate. The commenter notes that several of the emissions units listed in 40 CFR 52.43(c) emit or have the potential to emit less than 10 tons per year. The commenter states that controlling those emissions is not a cost-effective air pollution control measure.

Commenter (0287) states that the EPA's proposed emissions limit for EAFs is inconsistent with the stated control approach of RACT. The commenter relates that in this rule and all prior rulemakings for ozone transport, the EPA has emphasized that the levels of emissions controls being required for EGUs was consistent with RACT. According to the commenter, the approach the EPA actually used in the proposed rule when developing the emissions limit for EAFs is more analogous to a lowest achievable emissions rate (LAER) analysis. The commenter contends that the EPA started with the lowest emissions rates identified for EAFs and then applied an additional reduction based on an infeasible control device, which results in a proposed emissions limit that is beyond BACT.

Commenter (0514) states that the proposed rule does not cover SAFs or silicon production. The commenter remarks that the proposed regulatory text clarifies that the proposed rule only applies on a unit specific basis, not on the basis of NAICS code. The commenter further remarks that affected units (under NAICS code 3311) are expressly defined in terms of steel and iron manufacturing, which does not include facilities that do not produce steel. Specifically, according to the commenter, an EAF is limited to furnaces "used to produce carbon steels and alloy steels," a Ladle Metallurgy Furnace (LMF)is limited to furnaces "used to refine molten steel," Ladle/Tundish Preheaters are limited to equipment used "in iron or molten steel refinement," and Reheat Furnaces are limited to furnaces "used to heat steel product." Furthermore, the commenter notes that the limits specified in "Table 1 to Paragraph (c)" are set for EAFs and ladle metallurgy furnaces in terms of the unit "lb/ton steel," demonstrating that the limits on such units are only designed to apply to steel production. The commenter adds that an SAF is not listed among the affected units subject to the proposed rule, SAFs are distinct from furnace types subject to the proposed rule (*e.g.*, EAFs), and the EPA has consistently and expressly recognized these as different in its prior rulemaking efforts. Therefore, the commenter concludes that the proposed rule does not cover SAFs, or silicon metal production, and thus does not apply to the commenter's facility (MS Silicon). The commenter states that the proposed rule does not provide a basis for regulating its facility, SAFs, or Silicon Production.

The commenter declares that from a technical perspective, multiple factors contribute to SCR not being an appropriate choice for use on an EAF and outlines the following three factors:

(1) EAFs operate primarily using a batch process (rather than a continuous process). Emissions are generated during a cycle of charging, melting, and tapping. When being charged, the furnace roof is open, and emissions are not directly evacuated to the exhaust stack. Therefore, the emissions (and the characteristics of the exhaust stream) captured and evacuated to the primary control device (EAF Baghouse) through the direct shell evacuation control system (DEC), the system used on most new EAFs pursuant to 40 CFR part 60, subpart AAa, are intermittent and change during this operational cycle. An SCR is not a preferred control technology in these types of applications where the pollutant load concentration, exhaust temperature, and flow rates change regularly with a batch type process.

(2) The emissions during charging or other times the furnace roof is open are controlled through the use of a canopy hood that also evacuates to the EAF Baghouses. This hood collects air from not just from the open EAF but also from other emissions sources

within the melt shop building. This canopy hood then also evacuates to the EAF Baghouses. This exhaust stream will also, based on the nature of the operations within the Melt Shop at the time, have a varying pollutant load concentration, exhaust temperature, and flow rates which is unsuitable for an SCR. Based on the intermittent usage characteristics of the smaller heaters within the melt shop (ladle/tundish preheaters) and the fact that the emissions of these units are vented within the melt shop itself, any use of an SCR would have to be based on collection of NOx emissions from the canopy hood, which is not practical. This is similar to the annealing furnaces located outside the melt shop. These smaller units, often multiple sources less than 10 MMBtu, also vent individually within a building, precluding the practical use of SCR.

(3) The primary pollutant of concern (see 40 CFR 60, subpart AAa and 40 CFR 63, subpart YYYYY) from an EAF is particulate matter, and the use of the EAF Baghouses require the temperature of the exhaust stream to be around 300°F. An SCR would have to be located downstream of this baghouse to properly control NOx and prevent damage from particulate fouling. Therefore, use of an SCR would require the exhaust stream to be reheated after passing through the baghouse. Heating a high-volume exhaust stream like one from an EAF to proper temperature for SCR control would result in collateral emissions of NOx from the additional fuel that would have to be combusted to provide the heat.

The commenter also adds that there were no examples of SCR being used on EAFs in the RBLC in the previous five years of BACT determinations, and there is no evidence that the EPA provided any objection while reviewing these BACT determinations based on SCR being appropriate as BACT. According to the commenter, it is hard to conclude that the EPA conducted a detailed engineering analysis for the proposed controls in this industry sector. Further, the commenter asserts that proposing add-on controls to BACT emissions limit is purely political and is not remotely based on a scientific approach.

Commenters (0280, 0380, 0405, 0504, 0798) have significant concerns with the Agency's proposed FIP, especially as it relates to EAF steelmakers in the iron and steel sector. The commenters claim that the EPA treats all steel industry furnace types the same, proposing SCR as the means to reduce NOx emissions for each. However, according to the commenters, these furnaces are not the same, noting that electric arc furnaces (EAFs) emit around 0.5 – 0.6 lb. of NOx/ton of steel produced, whereas some basic oxygen furnaces emit up to 1 lb. of NOx/ton of steel produced. However, the commenters point out that the EPA proposes SCR for both furnace types and assumes that SCR will result in similar NOx reductions for both, which is not likely. The commenters add that SCRs are not technically feasible for EAFs because they require consistent temperature and flow rates that do not exist in EAFs. The commenters remark that the EPA itself admits that there is no information that NOx emissions controls have been installed on EAF's or that suitable controls are available. The commenters add that it is important to note that the EPA's proposal is not based upon a technical engineering evaluation and contradicts the EPA's previous technical assessments of potential air pollution controls for EAFs. Commenter (0280) notes that the EPA included in the docket for the proposed rule a European Union (EU) Commission Report, "Best Available Techniques (BAT) Reference Document for Iron and Steel Production" as a technical evaluation of potential controls for the Iron and Steel industry. However, the commenter points out that the BAT reference document does not include the proposed controls of SCR technologies for EAF. This commenter adds that the EPA also fails to consider other negative air quality impacts, such as the likely increase in PM2.5 and ammonia, CO, CO2, and VOC emissions that will result from implementation of the proposed FIP. Commenter (0405) requests that any future ozone transport rulemakings including the Iron and Steel sector be patterned after the time proven Reasonably Available Control Technology (RACT) methodology that evaluates units on a case-by-case basis.

Commenter (0298) states that the EPA's screening assessment and technical support documents fail to evaluate any ferroalloy facilities. While the commenter recognizes that the EPA could not assess every industrial source in the broad category of non-EGUs, the commenter asserts that the EPA cannot propose to regulate an entire category of industrial sources (*i.e.*, ferroalloy manufacturing facilities) without evaluating a single ferroalloy EAF, particularly where EPA itself admits to the heterogeneity that exists in the industrial groupings. The commenter notes that none of the 10 facilities screened by the EPA for the Iron and Steel Mills and Ferroalloy Manufacturing industry group under NAICS code 3311 is a ferroalloy manufacturing facility, and none of these facilities operates EAFs. The commenter adds that the EPA also failed to include a single ferroalloy facility or EAF in its evaluation of NOx control technologies, emissions reduction potential and cost for control. Therefore, according to the commenter, the EPA's proposal to regulate the ferroalloy manufacturing industry under the proposed rule is arbitrary and capricious as the screening assessment fails to justify or support the regulation of ferroalloy facilities to address ozone regional transport for the 2015 ozone NAAQS, and the proposed rule contains no factual or technical basis for setting a NOx emissions limit for EAFs or the ferroalloy industry.

Commenter (0504) states that the EPA's own data demonstrate that steel industry NOx emissions do not contribute significantly to downwind nonattainment or interfere with maintenance. The commenter adds that the screening analysis through which the Agency determined that the iron and steel sector should be included in the proposed FIP identified only a handful of steel manufacturing facilities, including just two EAF steel facilities, that the EPA assessed collectively emit modest levels of NOx which, based on the EPA's modeling, then collectively contribute only incredibly miniscule levels of additional ozone at a handful of downwind monitors. According to the commenter, the EPA's contribution assumptions about even these two facilities are deeply flawed, and in fact, completely indeterminable due to irreconcilably inconsistent data and analysis in the administrative record. Nearly all the iron and steel sector facilities that the EPA linked to downwind monitors are integrated steel facilities that produce steel from iron ore using blast and basic oxygen furnaces, and not EAF steelmaking facilities, which produce steel from scrap metal using electrical energy. The commenter also states that the proposed FIP misconstrues the nature of EAF steel producers' NOx emissions and overstates the extent to which these emissions might contribute to downwind ozone nonattainment through interstate transport. The commenter says that the EPA underestimates the extent to which EAF steel producers already control precursor NOx emissions; uses overestimates potential emissions reductions, and underestimates that the costs at which emissions reductions can be achieved. The commenter urges the EPA to reconsider the inclusion of the iron and steel sector in the proposed FIP, and particularly EAF steel producers.

Response:

The EPA is not finalizing emissions limits related to blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and EAFs as proposed at this time. The only emissions units within Iron and Steel Mills and Ferroalloy Manufacturing that the EPA is finalizing requirements for are reheat furnaces and boilers. These comments are further responded to in Section VI.C.3 of the preamble and in the Final Non-EGU Sectors TSD.

Comment:

Commenter (0782) recommends that the following types of engines be exempt from the proposed requirements for stationary SI engines, similar to the exemptions in Colorado's regulations on engines: nonroad engines; emergency power generators that operate less than 250 hours per year on a rolling 12-month basis; internal combustion engines subject to an emissions control requirement under a MACT standard, a BACT limit, or a NSPS limit. The commenter further recommends that the EPA exempt non-emergency engines that operate less than 1,000 hours per year on a rolling 12-month basis, as requiring installation of emissions controls on low operating engines would not be cost-effective. The commenter suggests that the EPA should also consider whether a fleetwide or company-wide alternative compliance plan, similar to what is used in Colorado, is appropriate to adopt. The commenter relates that a fleetwide or company-wide plan requires an overall emissions percentage reduction based on fleetwide or company-wide engine operations, and owners and operators using this alternative plan must demonstrate that total NOx emissions allowed under the plan are less than or equal to the total NOx emissions allowed through compliance with the emissions standards on an individual engine basis. The commenter states that this type of alternative compliance plan affords owners and operators with the flexibility to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emissions reductions than would be achieved through compliance with the emissions standards on an individual engine basis.

Response:

For engines in Pipeline Transportation of Natural Gas, the EPA is finalizing emissions averaging provisions and exemptions for emergency engines. See Section VI.C.1 of the preamble and Section 2 of the Final Non-EGU Sectors TSD.

Comment:

Commenter (0386) strongly agrees with the EPA's determination that lime industry emissions do not warrant inclusion in the Agency's rulemaking and would like to confirm that to the best of the commenter's knowledge, there are no boilers in the lime industry. The commenter also states that if the EPA determines that it wants to consider regulating emissions from lime manufacturing plants in the future, any such proposal would require a new proposed rulemaking to allow the lime industry a meaningful opportunity to comment.

Response:

The EPA did not include the Lime and Gypsum Product Manufacturing industry in the final rule. This was identified as a Tier 2 industry in the Screening Assessment. However, the EPA was unable to identify the existence of any boilers in this industry. *See* Screening Assessment at 5, Table 1.

2.4 Issues Related to the Timing or Sequence of the EPA's SIP and FIP Actions

2.4.1 Requests to Resubmit SIPs Before Finalizing FIP

Comments:

Commenters (0235, 0279, 0281, 0284, 0289, 0295, 0320, 0322, 0323, 0331, 0338, 0341, 0363, *e.g.*0364, 0383, 0397, 0400, 0404, 0405, 0408, 0409, 0411, 0424, 0437, 0500, 0505, 0512, 0513, 0516, 0517, 0521, 0531, 0536, 0539, 0540, 0541, 0542, 0545, 0547, 0554, 0798), at large, believe that the proposed FIP is premature and request that states (*e.g.*, Kentucky, Louisiana, Arkansas, Wisconsin, Oklahoma) be given the opportunity to revise and resubmit their SIPs to correct identified deficiencies prior to the finalization of a FIP, and adjust generation shifting assumptions for each perspective state. Many of the commenters (0279, 0281, 0289) point out that, at the time of this FIP proposal, the EPA had not yet proposed action on several interstate transport SIPs submitted by states, including California, and requests that the EPA withdraw the proposed FIP and wait to re-propose it until after it has finalized actions on the submitted SIPs from the affected states. Commenters (0279, 0545) imply that the opportunity to correct plan deficiencies prior to the promulgation of a FIP is specifically afforded to states in section 110(c)(1) of the CAA, and according to the commenter (as well as commenters 0338, 0341, 0397, 0409, 0411, 0554) disregarding this provision contradicts the spirit of cooperative federalism. Commenter (0554) concludes from the EPA's actions that the Agency predetermined that these states would be subject to this FIP as its chosen policy outcome without following the required administrative procedure or working in good faith with the states to develop their SIPs. Similarly, commenters (0341, 0409, 0542) add that not doing so is a violation of CAA at 42 USC Section 7410(k)(5) – calls for plan revisions. Commenter (0782) recommends that the EPA provide states with the maximum two-year timeframe to revise their SIPs to ensure that they have adequate time to adequately address identified deficiencies, prepare and submit a SIP revision, and have EPA approve of the SIP revision.

Commenter (0323) states that the EPA "must offer adequate justification for both the proposed SIP disapprovals and the proposed FIP prior to urging states to remedy alleged deficiencies in their SIPs.

Commenter (0521) objects to the fact that the state of Missouri has not been given adequate time to redress the EPA's disapproval concerns within their current state plan or a chance to either enhance or supplement the record. The current schedule (implementation beginning in 2023) will unduly burden states' ability (including Missouri) to implement rule changes outside the normal review and oversight process. The commenter worries that the state in which they preside in (*i.e.*, Missouri) will be forced to absorb the federal plan allocation methodology without appropriate consent, comment and justification.

Commenter (0531) states that that the public needs more time to evaluate the differences between the results of the modeling used for development of SIPs and the modeling used to deny those SIPs. The commenter explains in the process of denying state [SIPs] and proposing a FIP, the EPA has developed new air quality modeling using the same model assumptions and inputs, except for changes in the mobile source inventory inputs, as was used in modeling for state [SIP] planning. The EPA then used the new model as a basis for proposing to deny several state SIPs, despite significant differences in the results of the new model and the previous version used for state SIP development. States impacted by the new model results have not had ample opportunity to review the new modeling in light of the denial of the [SIPs] prior to proposal of the FIP. The EPA should allow time for states to review the new model and the associated changes and if needed, make changes to the state [SIP] before EPA proposes to include the state in a FIP. The CAA allows time (up to two years) for states to modify a SIP after the EPA finds a SIP to be inadequate; the EPA has afforded states only days after disapproving [SIPs] before they proposed including the states in FIPs despite the new information in the modeling results. In the case of the state of Missouri, the new model severs the link(s) between Missouri and each monitoring locations to which Missouri was previously linked and now links Missouri to new monitor locations. The latest model shows no link between Missouri and the receptors Missouri was linked to in the previous model. The new model supports Missouri's [SIP] analysis of the linkages from the old model and verifies, as Missouri had indicated in its [SIP], that Missouri is not a significant contributor to ozone nonattainment at those monitor locations. The new modeling also claims to provide a new basis for establishing links between Missouri emissions sources and nonattainment monitors. However, these are new links. The EPA did not identify these new linkages to Missouri or give Missouri the opportunity to update their [SIP] based on this new data. Instead, the EPA proposed to deny the SIP and include Missouri in a proposed FIP before allowing Missouri to update their SIP submittal. The EPA should allow Missouri time to update the [SIP] before finalizing a FIP that includes Missouri.

Commenter (0541) explains that Alabama submitted its SIP in August 2018, and the EPA proposed to approve it in 2019. In February 2022, the EPA proposed to disapprove the SIP based on new modeling data that was not available at the time of Alabama’s initial submission. Consequently, Alabama withdrew its initial 2018 submission and submitted a new SIP in April 2022. On June 15, 2022, the EPA notified Alabama of certain procedural deficiencies in its SIP and found it to be incomplete. The EPA provided that Alabama may correct those deficiencies and resubmit its SIP for the EPA’s review. Commenter writes that once Alabama resubmits its SIP, the EPA should perform a full review and finalize action on that SIP before finalizing a FIP that includes Alabama. The commenter (0340) states in view of the change in linked downwind receptors and the addition of states that are now linked as contributing, Kentucky recommends that the EPA formally publish the 2016v2 modeling using the NODA process and provide states with adequate time to review the inputs to the modeling and provide corrections prior to the EPA performing modeling. Additionally, in the spirit of cooperative federalism, Kentucky should be afforded the opportunity to submit a revised SIP based on a review of the 2016v2 platform, as well as the documents, data, and modeling associated with the new platform. The EPA should not finalize a proposed FIP until modeling has been corrected and updated, and states have had an opportunity to both review, and use the model to develop and submit a revised transport SIP.

Commenter (0340) states that at the time of Kentucky's SIP submittal, "there were several guidance documents from EPA, as well as modeling data, available to review and use for the interstate transport demonstration. Specifically, two memos from EPA's OAQPS, dated March 27, 2018, and August 31, 2018, were available. EPA provided updated modeling information with the March 27, 2018, memo for states to consider in developing their interstate transport SIPs. Kentucky used the information provided in EPA's March 27, 2018, memo, associated modeling, and the recommended 1 ppb contribution threshold from the August 31, 2018, memo to evaluate the impacts of Kentucky emissions on downwind monitors. The result, using Step 2 of EPA's framework, was that one maintenance monitor, located in Harford County, MD, was identified to be evaluated for potential impact downwind." The commenter continues, "In this proposed rule, the EPA is taking actions based on the 2016v2 modeled data that was not made available to states until well past the statutory deadline for both I-SIP submittals, and the EPA's deadline for acting on those submittals. Based on the 2016v2 model, some of the downwind monitors linked to Kentucky have changed. Kentucky was not afforded any opportunity to review or develop a SIP addressing the two new monitors allegedly impacted by Kentucky's emissions. In the spirit of cooperative federalism, Kentucky would appreciate and expect the opportunity to submit a revised SIP utilizing the 2016v2 platform and modeling, rather than having a FIP immediately imposed.

Commenter (0539) comments that the EPA should have evaluated and approved Minnesota's SIP based on data available to the MCPA at the SIP's time of preparation, not some future time. Commenter (0798) concurs that the EPA cannot issue a FIP or disapprove SIPs based on data not available at the time that SIP submissions were required. The commenter explains the EPA reevaluated the significance of contributions to downwind receptors based on data generated after the statutory deadline for the EPA to act on approving or disapproving the Arkansas Transport SIP submission. Had the EPA reviewed the SIP in the timeframe required by federal law, the information available at the time—the same information that states used to inform their decisions—would not have supported a decision to disapprove the SIP for Arkansas, and subsequently would remove any statutory basis for the EPA to promulgate a FIP for Arkansas. Although the D.C. Circuit has held that the EPA has legal authority to propose a FIP at the same time it disapproves a SIP submission without giving the state an opportunity to fix the deficiency in the SIP submission, we are aware of no decision or statutory basis that would allow the EPA to do so based on data that was unavailable to the state at the time that it made its SIP submission. On the contrary, "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 or else be held liable when the agency announces its interpretations for the first time . . . and demands deference." Accordingly, it was unreasonable and unlawful for the EPA to disapprove the Arkansas submission based on data that the agency did not generate until after its statutory deadline to act on the Arkansas Transport SIP. Because the EPA erred in denying the Arkansas Transport SIP, it was also not lawful for the EPA to propose the proposed rule FIP to cover Arkansas, since the EPA only has the authority to issue a FIP if a state failed to submit an approvable SIP or the EPA properly disapproved it.

Commenter (0341) explains that Kentucky submitted its SIP on January 11, 2019, and the EPA based its proposed disapproval of the SIP on information and modeling that was not available to the state when it was originally submitted.

Commenter (0346) notes that "in its disapproval of the Texas SIP submission, the EPA argues that Texas failed to include recommendations in EPA guidance regarding contribution thresholds and identifying receptors. However, the guidance cited by the EPA was not issued in a timely manner such that states could rely on it in developing their SIP revisions. The EPA issued the "Analysis of Contribution Thresholds Memo" on August 31, 2018 – just 31 days before the SIP revisions were due. The EPA issued another guidance document "Considerations for Identifying Maintenance Receptors Memo" (Maintenance Receptor Guidance) on October 18, 2018 – 18 days after the SIP deadline. Because Texas submitted its SIP revision on August 17, 2018, both guidance documents were issued after Texas had submitted its revisions." Commenter writes that it is unreasonable for the EPA to require Texas' SIP revisions to include recommendations from memoranda and/or guidance issued after Texas submitted those revisions. Commenter adds that several positions taken by the EPA in the SIP disapprovals and proposed rule directly contradict the 2018 guidance that the proposed SIPs relied on. Commenter continues by explaining that the EPA cites the Texas Commission on Environmental Quality's (TCEQ's) failure to use the EPA's modeling platform and monitoring data in its SIP revision, which were not available at the time TCEQ developed its SIP revision. The TCEQ submitted its 2015 Ozone NAAQS Transport SIP Revision to the EPA on August 17, 2018. The EPA did not issue the modeling platform used in its disapproval until September 2021, nearly three years after the deadline to submit the SIP revision. Commenter states that TCEQ did use the latest modeling data available at time of its submission (EPA's 2011-base modeling.) Commenter writes that it is unreasonable for the EPA to evaluate the TCEQ's submission based on data that was unavailable during the development and submittal of its SIP revision.

Commenter (0505) writes that the proposed rule as well as the proposed disapproval of Texas's SIP are inconsistent with the EPA's guidance and based on flawed methods for assessing significant contributions and related control requirements. Commenter explains the EPA specifically allowed states to use any of several different methods to demonstrate compliance with transport obligations. The EPA's proposed disapproval grossly mischaracterizes the demonstration that Texas submitted when it states that Texas did not appropriately consider whether any emissions from Texas contributed to nonattainment or interference with maintenance at potentially linked monitors.

The commenter notes the EPA purports to allow states flexibility in approaches to demonstrating that they meet transport obligations, including in its discussion of the proposed Texas disapproval (See 87 FR 9798, at 9831-32). However, the EPA then evaluates submitted transport SIPs on its preferred method, even though that is not required for approval. The EPA continues to insist that it if a state has emissions that can mitigate the 0.7 ppb ozone concentration used to link it to downwind monitors, and if so, that is enough, without following the logical next step to determine if those emissions actually contribute in a significant manner to actual nonattainment or maintenance issues at those monitors. More specifically, the EPA continues to refuse to acknowledge the need to first make a determination as to whether linked upwind states emissions actually contribute significantly to ozone concentrations at the downwind monitors taking into consideration the relationship of all emissions (transported and local) with meteorology and other local specific factors.

Commenter (0912L) writes that the proposed FIP should be withdrawn until the SIP revisions can be meaningfully reviewed.

Response:

As an initial matter, comments regarding the EPA's basis for disapproving SIPs are beyond the scope of this action. Comments regarding the 2018 memoranda and the use of new modeling are addressed in Section 1.1 (Sequencing of SIP and FIP actions). In response to arguments that the EPA must or should delay this action so that states can reexamine the most recent information and resubmit SIP submissions, the EPA notes that there is no support in the CAA for such a delay. CAA section 110(a)(1) requires states to adopt and submit SIP submissions meeting certain requirements including the requirements of CAA section 110(a)(2)(D)(i)(I), "within 3 years (or such shorter period as the Administrator prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof)." CAA section 110(a)(1). The submission deadline runs from the date of promulgation of the NAAQS, which for the 2015 ozone NAAQS was October 1, 2015. 80 FR 65291 (Oct. 26, 2015). In addition, while the Administrator is given authority to prescribe a period shorter than three years for the states to adopt and submit such SIP submissions, the Act does not give the Administrator authority to lengthen the time allowed for CAA section 110(a)(2) submissions. Once EPA has taken action to disapprove SIP submittals, the EPA must promulgate a FIP within two years. CAA section 110(c)(1).

Further, comments asserting that the EPA must give more time to states to correct deficiencies and re-submit are in conflict with the controlling caselaw in that such an opportunity is not required within the procedural framework of CAA section 110 and would further conflict with the attainment schedule of CAA section 181 that the D.C. Circuit has now held multiple times should be the animating focus of good neighbor obligations. 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),[20] and the EPA may not delay implementation of measures necessary to address good neighbor requirements beyond the next applicable attainment date without a showing of impossibility or necessity.[21] Further, the court pointed out that the CAA section 110 schedule of SIP and FIP deadlines is procedural, and while the EPA has complied with the mandatory sequence of actions required under section 110 here, we are mindful of the court's observation that, as compared with the fundamental substantive

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[20] *Wisconsin v. EPA*, 938 F.3d 303, 313-14 (D.C. Cir. 2019) (citing *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). On May 19, 2020, the D.C. Circuit in *Maryland v. EPA*, applying the *Wisconsin* decision, held that the EPA must assess air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b). *Maryland v. EPA,* 958 F.3d 1185, 1203-04 (D.C. Cir. 2020).

[21] *See* 938 F.3d at 320.

obligations of title I of the CAA to attain and maintain the NAAQS, the maximum timeframes allotted under section 110 are less “central to the regulatory scheme[.]”[22]

Other commenters take the position that states are owed a second opportunity to submit SIP submissions before the EPA takes final action for various reasons, including claims that the EPA failed to issue adequate guidance or is otherwise walking back previously issued guidance. They allege that a state cannot choose controls to eliminate significant contribution until the EPA quantifies the contribution. The EPA disagrees, because as noted in *EPA v. EME Homer City Generation, L.P.*, the Supreme Court clearly 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.”[23] (Comments specific to the memoranda and modeling the EPA issued in 2018 are addressed in Section 1.1 (Sequencing of SIP and FIP Actions).

2.4.2 Timing of SIP Submissions, SIP Denials, and FIP Proposal

Comments:

Commenters (0235, 0289, 0306, 0340, 0363, 0364, 0365, 0367, 0383, 0396, 0398, 0404, 0408, 0499, 0505, 0509, 0512, 0519, 0536, 0540, 0547, 0554, 0782) write that the EPA failed to take timely action in response to SIPs submitted, for example, by California, Nevada, Texas, Arkansas, Missouri, Kentucky, Nevada, Wyoming, Utah, Louisiana, Michigan, Ohio, West Virginia, and Oklahoma. Commenter (0365) states that by proposing a FIP that covers states whose SIPs were not approved or disapproved in a timely manner (within one year after submittal), the EPA violates the CAA, 42 U.S.C. § 7410(k)(2) and 42 U.S.C. § 7410(c)(1) – failure to promulgate a FIP within two years after finding that a state failed to submit an appropriate SIP or disapproval of a SIP (partially or at large). Additionally, commenter (0367) provides a brief description of recent litigation efforts by states.

Commenters (0235, 0295) express concern that the timing for the proposed FIP occurs within the middle of the planning cycle for the 2015 ozone (O_3) NAAQS. Commenters observe that it appears that the EPA is prejudging planning activities which have not yet been completed or submitted as inadequate and/or ineffective. Commenters state that if the EPA considers a planning effort and resultant control measures to be inadequate, the proper response is to disapprove or partially disapprove the plan, and only when failure to address properly identified deficiencies has occurred, issue a FIP.

Commenters (0359, 0365, 0372, 0513, 0513, 0519) argue that the EPA is finalizing states’

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[22] *Wisconsin v. EPA*, 938 F.3d at 322 (“Delaware’s argument leans too heavily on the SIP submission deadline. SIP submission deadlines, unlike attainment deadlines, are "procedural" and therefore not "central to the regulatory scheme.") (citing *Sierra Club*, 294 F.3d at 161 (D.C. Cir. 2002)).

[23] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 510 (2014).

proposed SIP disapprovals in a manner that circumvents its responsibility to respond to public comments, as specificized in the APA's notice-and-comment procedures. In the cases of West Virginia, commenter (0359) claims that the EPA blatantly denied West Virginia the opportunity to act on any proposed deficiencies, as the comment period for the proposed disapproval was still open when the EPA proposed its FIP. Commenters (0365, 0372) add that, in the case of Kentucky and Louisiana, the EPA chose to propose the rule before the end of the SIP disapproval comment period (April 25, 2022). Commenter (0513) recalls a similar outcome for Nevada and Wyoming; claiming that the EPA is effectively depriving members of the public from meaningfully engaging with its proposed disapprovals by issuing these proposals after its proposed FIP. The commenter highlights that the comment period for Nevada and Wyoming did not open until over a month after the EPA published its proposed FIP, meaning that the comment period for the proposed FIP will close before many commenters have a chance to submit comments on the proposed SIP disapprovals. The commenter concluded that this puts commenters in the untenable position of having to provide feedback on the EPA's comprehensive and complex "Good Neighbor" plan without first understanding their state's obligations under the CAA. Commenters (0513, 0519) suggest that the EPA cannot effectively consider its proposed disapproval where the validity of its FIP depends on the disapproval being finalized.

Commenters (0359, 0365, 0372, 0395, 0500, 0519) insist that states submitted appropriate SIPs, which contained all "necessary provisions" that were required at the time by the EPA to constitute an approvable SIP. The commenters express frustration that the state disapproval SIP (for Alabama, Kentucky, Louisiana, Oklahoma, Mississippi, Texas, West Virginia) was not published until nearly three years past the 18-month deadline, on February 22, 2022.

Commenter (0547) notes that the proposed rule states that the EPA will not finalize a FIP for Wyoming unless and until the agency formally finalizes disapproval or Wyoming withdraws its SIP submissions.

Commenter (0281) writes that conducting the public process for the FIP before any SIP disapprovals are finalized breaks with the EPA's past practices and may be counterproductive to California's efforts to reduce transport impacts.

Commenters (0400, 0405, 0509, 0512, 0513, 0518, 0519, 0541, 0550, 0760) object to the EPA's choice to propose a FIP before the end of the public comment period for the proposed SIP disapprovals and before some SIP disapprovals were proposed at all. Commenters (0400, 0512, 0513) add that this deprives the public, states, and affected entities the opportunity to submit meaningful public comment. Commenter (0323) further states that the EPA has not provided "legally sufficient" public notice and comment and requests "adequate time for state response and public comment and review."

Commenter (0400) writes, "EPA's review of each state's SIP submissions should have been an opportunity for consultation in which the EPA could outline differences of opinion regarding technical issues and the states could then harmonize their submissions. Instead, the EPA did not afford the opportunity for revision that could result from a SIP call before proposing the FIP. As a result, the FIP lacks any meaningful evaluation of grid reliability concerns and any evidence of consultation with those on the front lines of grid stability—the states, Regional

Transmission Organizations (RTOs), FERC or NERC. In doing so, the EPA has unlawfully commandeered state discretion to address good neighbor obligations and has given States no choice in the implementation of its rule."

Commenter (0428) writes that the proposed rule is premature because EPA did not sufficiently consult with states in the Western States Air Resources Council (WESTAR) region regarding their participation in past EPA-mandated regional NO_X control programs. Commenter adds that the proposed rule was proposed with no prior consultations with respect to the programmatic approach and additional implementation effort it would require of states.

Commenter (0396) states that "EPA's failure to take timely action on Louisiana's SIP or propose a FIP sooner is no excuse for leaving states with insufficient time to evaluate EPA's decision, which essentially amounts to replacing state policy choices with its own."

Commenter (0306) states that the proposed rule was issued before the end of the comment period for the proposed Texas SIP disapproval and argues that this deprived Texas of a meaningful opportunity to correct deficiencies in its SIP. Commenter (0365) makes the same observation regarding Louisiana's SIP. Commenters (0512, 0513) makes the same point regarding Wyoming's SIP. Commenter (0513) makes the same comment regarding Nevada's FIP.

Commenter (0323) comments that "EPA's inaction relative to its relationship with air program managers demonstrates its failure to foster meaningful stakeholder involvement."

Commenters (0346, 0505) note that the EPA published the proposed FIP on April 6, 2022, before the deadline for comments regarding the proposed disapproval of the Texas SIP, on April 26, 2022. Commenters add that unlike in EME Homer, Texas has not had an opportunity to challenge the EPA's disapproval of the SIP. Commenter (0346) explains that although the EPA conducted extensive work to include Texas in a proposed FIP during the three years after the state submitted its SIP, it "never communicated to TCEQ that the Texas SIP submission failed to address its concerns." Commenter writes that this did not allow the TCEQ to address any issues outlined in EPA's proposed disapproval in a SIP revision. Commenter (0505) concurs that "EPA never indicated that Texas' SIP was inadequate during the years of work that went into the development of this FIP, nor was Texas afforded any opportunity to correct the deficiencies that the EPA determines are present in the SIP. Had the EPA reviewed the 2015 Ozone NAAQS Transport SIP Revision before developing a proposed FIP, the purpose of which is to correct deficiencies in such a SIP, Texas would have had the opportunity contemplated by the FCAA to correct any problems with its SIP in a timely fashion and avoid the imposition of the FIP."

Commenters (0365, 0405, 0509, 0512, 0513, 0518, 0519, 0541, 0550) write that by taking action before considering comments on the proposed disapprovals, the EPA is presupposing the outcome of its proposed rulemakings on the SIPs. Commenters (0512, 0513, 0519) add, "EPA cannot remain flexible and open-minded in its consideration of its proposed disapproval where the validity of its proposed FIP depends on this disapproval being finalized." Commenter (0365) claims that D.C. Circuit's holding in Wisconsin v. EPA does not give the EPA authority to begin promulgation of the FIP prior to taking action on the states' SIP submissions.

Commenters (0300, 0365, 0411, 0424, 0509) write that the EPA violates congressional intent and cooperative federalism by denying previously submitted SIPs after considerable delay, then proposing a FIP before the states are able to respond or provide thorough input.

Commenter (0300) explains that Mississippi submitted its SIP in September 2019, then two and a half years later, the EPA proposed to disapprove the plan based on its modeling results, "which were not complete, much less available when Mississippi submitted its plan for approval." Commenter notes that the proposed FIP was signed within one week, which "disenfranchises meaningful participation by all stakeholders." Commenter requests that states be given the opportunity to submit a supplemental demonstration and/or a SIP revision before a FIP is proposed.

Commenter (0365) states that the EPA proposed the FIP before issuing the final SIP disapproval for Louisiana and should have afforded the state the opportunity to address the SIP first.

Commenter (0436) requests that the EPA consider ways to align its agency more efficiently so that the policy priorities of the current administration better align with the implementation and timing of CAA requirements at the regional and state level. The commenter is committed to developing and enforcing SIPs that meet all of the statutory requirements of the CAA and doing so in the spirit of cooperative federalism and collaboration with our EPA partners. However, they express concerns that uncertainties of SIP approval make it difficult for to coordinate and co-develop plans with respective regional office.

According to the commenter (0506) the attainment deadline for ozone nonattainment areas currently designated as Moderate nonattainment for the 2015 ozone NAAQS is August 2024. Because August 2024 falls during the 2024 ozone season (which runs May 1 through September 30), the 2023 ozone season will be the last full ozone season from which data can be used to determine attainment of the NAAQS by the August 2024 attainment date. 87 Fed. Reg. at 20,060. The D.C. Circuit's decisions in North Carolina and Wisconsin compel the EPA to impose FIPs that require upwind states to eliminate their significant contributions to downwind air quality problems, to the extent possible, by the 2023 ozone season. The commenter agrees with the EPA that there is considerable NO_X reduction potential from electric generating units (EGUs) that can be achieved for the 2023 ozone season at reasonable cost. In light of the failure of states to submit SIPs that adequately address their good neighbor provision obligations for the 2015 ozone NAAQS, the EPA should promptly impose FIPs so that much needed and meaningful emissions reductions can be achieved as soon as possible."

Commenter (0528) states that the EPA failed to align the parallel deadlines of upwind and downwind states to address nonattainment of the ozone NAAQS.

Commenter (0506) notes that the U.S. Court of Appeals for the District of Columbia Circuit held that the EPA must align interstate transport compliance deadlines under the good neighbor provision with deadlines for downwind states to achieve attainment with the NAAQS. Commenter explains the EPA has long interpreted the CAA to require upwind states to satisfy their good neighbor provision obligations "as soon as practicable." The EPA reasoned that that interpretation is "consistent with Congress' intent that attainment occur in . . . downwind nonattainment areas 'as expeditiously as practicable' (sections 181(a), 172(a)).

Response:

Several commenters argued that because the EPA proposed FIPs prior to finalizing disapproval of the state SIP submission, the EPA allegedly exceeded its statutory authority and overstepped the states' primary role in addressing the good neighbor provision under CAA section 110. Some commenters suggest that the EPA never gave the state SIP submissions the appropriate review or suggest that the EPA's review of the SIP was prejudiced by the FIP it had proposed. While comments regarding the SIP disapprovals are beyond the scope of this action, to the extent these comments allege some deficiency in the promulgation of this action, the EPA disagrees with commenters. The EPA has followed the CAA provisions which prescribe an amount of time in which a state is to make SIP submissions and requires the EPA to take action on those SIP submissions. The Supreme Court confirmed in *EPA v. EME Homer City Generation*, "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." 572 U.S. 489 at 509. The procedural timeframes under CAA section 110 do not function to establish a norm or expectation that the EPA must or should use the full amount of time allotted, particularly when doing so would place the Agency in conflict with the more "central" statutory objective of meeting the NAAQS attainment deadlines in the Act. *EPA v. EME Homer City*, 572 U.S. 489, 509 (2014). *See also Wisconsin v. EPA*, 938 F.3d 303, 318, 322 (D.C. Cir. 2019); *Sierra Club v. EPA*, 294 F.3d 155, 161 (D.C. Cir. 2002). Further, the Agency has been clear, including at the time it proposed this action, that it would not finalize a FIP for any state until predicate authority is established for doing so under CAA section 110(c)(1). 87 FR 20036, 20057 (April 6, 2022) ("The EPA is proposing this FIP action now to address twenty-six states' good neighbor obligations for the 2015 ozone NAAQS, but the EPA will not finalize this FIP action for any state unless and until it has issued a final finding of failure to submit or a final disapproval of that state's SIP submission."). The EPA strongly disagrees that *proposing* a FIP prior to proposing or finalizing disapproval of a SIP submission oversteps the Agency's authority. Indeed, the ability to propose a FIP before finalizing a SIP disapproval follows ineluctably from the structure of the statute, which, as the Supreme Court recognized in *EME Homer City*, does not oblige EPA "to wait two years or postpone its [FIP] action even a single day." 572 U.S. 489, 509. If the EPA can finalize a FIP immediately upon disapproving a SIP, then the EPA must have the authority to propose that FIP before taking final action on the SIP. *Accord Oklahoma v. U.S. EPA*, 723 F.3d 1201, 1223 (10th Cir. 2013).

Further, the sequencing of our actions here is consistent with the EPA's past practice in our efforts to timely address good neighbor obligations. For example, at the time the EPA proposed the CSAPR Update FIPs in December of 2015, we had not yet proposed action on several states' SIP submissions, but finalized those SIP disapproval actions prior to finalization of the FIP.[24]

[24] The proposed CSAPR Update was published on December 3, 2015, and included proposed FIPs for Indiana, Louisiana, New York, Ohio, Texas, and Wisconsin. 80 FR 75705. At that

Some commenters argue that the sequence of the EPA's actions is improper, unreasonable or bad policy, but the EPA disagrees. 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),[25] and states and the EPA may not delay implementation of measures necessary to address good neighbor requirements beyond the next applicable attainment date without a showing of impossibility or necessity.[26] It is important for the states and the EPA to assure that necessary emissions reductions are achieved, to the extent feasible, by the 2023 ozone season to assist downwind areas with meeting the August 2024 attainment deadline for Moderate nonattainment areas. Further, the D.C. Circuit in *Wisconsin* emphasized that the EPA has the authority under CAA section 110 to structure its actions so as to ensure necessary reductions are achieved by the downwind attainment dates,[27] the next of which for the 2015 ozone NAAQS is now the Moderate area attainment date of August 3, 2024.[28] Thus, the sequence and timing of the EPA's action in disapproving the SIP submissions was informed by the need to ensure that any necessary good neighbor obligations identified in this FIP rulemaking could be implemented as expeditiously as practicable and no later than the next attainment date to the extent possible. We note that states' and the EPA's analysis would have been more appropriately aligned with 2020, rather than 2023 (as had been presented in the

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time, EPA had not yet proposed action on good neighbor SIP submissions for the 2008 ozone NAAQS from Indiana, Louisiana, New York, Ohio, Texas, and Wisconsin; however, EPA subsequently proposed and finalized these disapprovals before finalizing the CSAPR Update FIPs, published on Oct. 26, 2016 (81 FR 74504). *See* 81 FR 38957 (June 15, 2016) (Indiana); 81 FR 53308 (Aug. 12, 2016) (Louisiana); 81 FR 58849 (Aug. 26, 2016) (New York); 81 FR 38957 (June 15, 2016) (Ohio); 81 FR 53284 (Aug. 12, 2016) (Texas); 81 FR 53309 (Aug. 12, 2016) (Wisconsin).

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

[26] *See* 938 F.3d at 320.

[27] *Wisconsin v. EPA*, 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)).

[28] *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 Aug. 3, 2018). *See also Wisconsin v. EPA*, 938 F.3d at 322 ("Delaware's argument leans too heavily on the SIP submission deadline. SIP submission deadlines, unlike attainment deadlines, are "procedural" and therefore not "central to the regulatory scheme.") (citing *Sierra Club*, 294 F.3d at 161 (D.C. Cir. 2002)).

EPA's March 2018 memorandum[29]), corresponding with the 2021 Marginal area attainment date. However, that clarification in obligations was not established by case law until 2020. *See Maryland v. EPA*, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020).

Nothing in the language of CAA section 110(c) prohibits the EPA from proposing a FIP as a backstop, to be finalized and implemented only in the event that a SIP submission is first found to be deficient and final disapproval action on the SIP submission is taken. Such an approach is a reasonable and prudent means of assuring that the statutory obligation to reduce air pollution affecting the health and welfare of people in downwind states is implemented without delay, either via a SIP, or where such plan is deficient, via a FIP. The sequencing of the EPA's actions here is therefore reasonably informed by its legal obligations under the CAA, including in recognition of the fact that the implementation of necessary emissions reductions to eliminate significant contribution and thereby protect human health and welfare is already several years delayed.

Nor is the EPA depriving States of the opportunity to target specific emissions reductions opportunities, or the opportunity to revise their submissions at any point in the future. See Section VI.D of the preamble and Section 1.11.3.1 of this document.

The EPA disagrees with assertions in comments that the EPA is pursuing an alleged objective of establishing federal standards throughout the whole country via these FIPs. To date, the EPA has approved 24 good neighbor SIPs for the 2015 ozone NAAQS. 83 Fed. Reg. 47,568 (September 20, 2018) (Washington); 84 Fed. Reg. 69,331 (December 18, 2019) (Alaska); 84 Fed. Reg. 22,376 (May 17, 2019) (Oregon); 85 Fed. Reg. 5,570 (January 31, 2020) (Washington, D.C.); 85 Fed. Reg. 5,572 (January 31, 2020) (Massachusetts); 85 Fed. Reg. 20,165 (April 10, 2020) (Colorado and North Dakota) (Colorado later remanded and approval finalized after reproposal, 87 FR 61249, Oct. 11, 2022); 85 Fed. Reg. 21,325 (April 17, 2020) (Nebraska); 85 Fed. Reg. 25,307 (May 1, 2020) (Delaware); 85 Fed. Reg. 34,357 (June 4, 2020) (Vermont); 85 Fed. Reg. 65,722 (October 16, 2020) (Idaho); 85 Fed. Reg. 67,653 (October 26, 2020) (South Dakota); 86 Fed. Reg. 45,870 (August 17, 2021) (Maine and New Hampshire); 86 Fed. Reg. 68,413 (December 2, 2021) (Florida, Georgia, North Carolina, South Carolina); 86 Fed. Reg. 70,409 (December 10, 2021) (Rhode Island); 86 Fed. Reg. 71,830 (December 20, 2021) (Connecticut); 86 Fed. Reg. 73,129 (December 27, 2021) (Hawaii); 87 Fed. Reg. 19,390 (April 4, 2022) (Kansas); 87 Fed. Reg. 21,578 (April 12, 2022) (Montana); and 87 Fed. Reg. 22,463 (April 15, 2022) (Iowa).

The legal and technical basis for this action to implement requirements under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS through FIPs covering 23 states is set forth in the preamble, this document, and the other supporting materials in the docket.

[29] *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"), available in Docket ID No. EPA-HQ-OAR-2021-0663.

2.4.3 States' Objections to SIP Disapprovals

Comments:

Commenters (0306, 0395, 0505, 0528) argue that the Texas SIP should be approved by the EPA and Texas should be excluded from the proposed FIP. Commenter (0395) adds that "Texas's SIP fully satisfies the requirements of the CAA and EPA failed to technically or legally justify its decision to disapprove Texas's SIP. Without a lawful disapproval, the EPA has no authority to issue a FIP for Texas."

Commenter (0317) argues that the Arkansas SIP "contains adequate provisions to prohibit any source or other type of emissions activity from emitting NO_X in amounts that will contribute significantly to nonattainment or that will interfere with maintenance of the 2015 ozone NAAQS by any other states." Commenter quotes *Train v. Nat. Res. Def. Council, Inc.,* as follows:

> "The Act gives the Agency no authority to question the wisdom of a State's choices of emissions limitations if they are part of a plan which satisfies the standards of s 110(a)(2), and the Agency may devise and promulgate a specific plan of its own only if a State fails to submit an implementation plan which satisfies those standards. s 110(c). Thus, so long as the ultimate effect of a State's choice of emissions limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emissions limitations it deems best suited to its particular situation."

The commenter states that the proposed rule "effectively mandates the use of particular control technologies in specific industry sectors to meet NAAQS standards." Commenter notes that "Although the FIP provides that states may submit SIPs to address the provisions of the FIP (87 F.R. at 20149), the FIP provides no realistic ability for states to do so except as mandated in the FIP, particularly for non-EGU sources. For EGU sources, the FIP sets forth alternatives available to trading programs for EGUs that a state may adopt (87 F.R. 20150-151), but it provides no such alternatives for non-EGUs. In fact, the FIP essentially states that the EPA will not approve a substitute SIP for non-EGUs that does not "include emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources . . . identified in Section VII.C of this proposed rule." (87 F.R. 20151). The EPA's FIP neither provides nor signals the EPA's intent to approve SIPs for non-EGUs that do not adopt the EPA's specific emissions control requirements. Commenter argues that the EPA may not "condition approval of a state's implementation plan on the state's adoption of a particular control measure", which the FIP purports to do.

Commenter (0317) comments that the EPA failed to meet its statutory deadline to act on Arkansas's SIP submittal and objects to the EPA's disapproval of the SIP on the grounds that the EPA may not "substitute its own policies for those that the state has demonstrated are reasonable and consistent with the Clean Air Act" as this goes against "the Congressional grant of authority to the states who are the primary authority in establishing plans to protect air quality standards." Commenter (0398) concurs that Arkansas should not be subject to the proposed FIP, and the EPA should instead approve the original Arkansas SIP submission.

Commenter (0326) states that the proposed disapproval of Tennessee's SIP is premature, arbitrary, and capricious and that the EPA may not take final action until the EPA is able to fully address the issues identified by Tennessee. Commenter adds that it "does not object to participation in the proposed trading program, or more generally, to the EPA's use of emissions trading to address interstate transport."

Commenter (0331) states that the EPA was mistaken in its disapproval of Minnesota's SIP, which showed that Minnesota was a minor contributor to any downwind ozone monitors, and adds that the proposed FIP is "based on flawed modeling" that should not include Minnesota.

Commenters (0397, 0508, 0517) object to the disapproval of Oklahoma's SIP and argue that it should be approved.

Commenter (0340) disagrees with the EPA's finding that NO_X emissions from Kentucky sources interfere with attainment or maintenance of downwind receptors.

Commenter (0798) writes that the EPA does not have the authority to impose a FIP when adequate and approvable SIPs have been submitted to the EPA. Commenter argues that nineteen states have submitted SIPs that meet CAA requirements and should be approved.

Commenters (0359, 0500) argue that the EPA lacks a legal basis to disapprove state SIPs merely on the premise that they "[do] not meet the State's interstate transport obligations, because [they fail] to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the 2015 8-hr ozone NAAQS in any other state," largely because the EPA has substantially altered its analysis of downwind air quality problems and state linkages, since submitting their perspective state SIP – *i.e.*, reevaluated and modified what it considers as acceptable "necessary provisions" to meet the requirements of the 2015 Ozone good neighbor SIP. The commenters stress that this was done without communicating changes to states; making it impossible for states to predict, much less meet SIP requirements, which are, according to the commenters, in constant fluctuation, poorly or not defined and never acted upon.

According to the commenter (0499) the EPA also cannot substitute its own judgment for that of the state's in crafting a SIP, as the courts have recognized. Accordingly, the fact that the EPA has consistently applied Step 3 of its 4- Step framework to identify "significant" emissions contributions for its ozone transport FIPs and "this interpretation of the statute has been upheld by the Supreme Court," has no bearing on whether a state's different choices for its own SIP are approvable under the CAA. In determining whether a state's emissions significantly contribute to nonattainment or interfere with maintenance, the EPA explains that "states must complete an analysis similar to the EPA's (or an alternative approach to defining "significance" that comports with CAA requirements.)" Yet, there is no requirement in the CAA that states must complete an analysis similar to the EPA's and the EPA has not attempted to adopt regulatory standards that purport to define the regulatory requirements for interstate transport SIPs. The EPA's analysis of Louisiana's approach for defining significant contribution with respect to whether there is a "persistent and consistent" pattern of contribution from the state appears largely focused on explaining that the state's approach is inferior to the EPA's rather than on explaining why the state's determination does not comport with the CAA.

The commenter writes, accordingly, the EPA's Proposed Disapproval of Louisiana's SIP falls short and the EPA has overstepped its authority under the CAA. The EPA should re-evaluate Louisiana's SIP on the basis of whether the SIP meets the applicable requirements of the CAA, not on the basis of whether Louisiana made different choices than the EPA would have made had it been the decision-maker with respect to fulfilling the state's good neighbor obligation to address interstate transport of ozone under section 110(a)(2)(D)(i)(I) of the CAA. The EPA also must avoid any policy determinations or a desire to adopt a 'national ozone transport policy' in evaluating Louisiana's SIP.

Commenter (0502) acknowledges that states have the authority and the obligation under the CAA and its supporting regulations to address ozone pollution and its precursors that transport to neighboring states. Commenter writes had states taken this obligation and authority seriously and addressed ozone transport in their respective ozone SIPs, the proposed FIP would not be necessary. Unfortunately, most states failed to seriously address ozone transport in SIP.

Commenter (0502) observes that during the public hearing on the proposed FIP, "many businesses cited unique local circumstances that made compliance… functionally or economically challenging. Commenter notes state air resources officers, through the SIPs. Have the authority to recognize and address local economic and implementation challenges. Had state air resource officials used their authority wisely in the SIP, many of these local issues could have been addressed by state planners while still meeting the overall state requirement to meet the ozone standard.

The commenter (0502) "urges state local air officials to use their authority more proactively for future CAA standard attainment efforts."

Commenter (0499) writes that it is inappropriate for the EPA to propose "to apply a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submittals for the 2015 ozone NAAQS." The commenter explains policy judgments have no place in determining whether a SIP meets applicable CAA requirements. With respect to the EPA's proposed disapproval of Louisiana's SIP, the EPA is proposing to disapprove of Louisiana's use of an alternative 1 ppb threshold to identify projected nonattainment and/or maintenance receptors in other states, in part due to the EPA's determination that use of an alternative threshold "may be impractical or otherwise inadvisable for a number of additional policy reasons. Impracticality, like policy reasons, play no part in whether a SIP meets the applicable CAA requirements.

Further, the EPA cannot base disapproval of a SIP on the fact that states, even when following the 4-Step interstate transport framework that the EPA has established, may apply different thresholds in Step 2 of the interstate transport framework, which would have "the potential to result in inconsistent application of interstate transport obligations based solely on the strength of a state's SIP submittal at Step 2 of the 4-Step framework." The states, in the first instance, have wide discretion in determining how to achieve the NAAQS, including their interstate transport obligations, and the EPA cannot force the states to adopt approaches reflecting the Agency's policy preferences for consistency in interstate transport obligations. A "SIP basically embodies a set of choices . . . that the state must make for itself in attempting to reach the NAAQS with minimum dislocation."

Commenters (0400, 0409) write that the EPA has not provided a meaningful opportunity for states to exit the CSAPR-FIP process by proposing a flexible off-ramp option, which unlawfully commandeers state discretion to address good neighbor obligations, departing from the statutory framework Congress has set. Commenter (0500) adds that the EPA should revise proposed section 52.38(b)(12) language to emphasize that adopting provisions substantively identical to the FIP is only one potential option for states to develop a good neighbor SIP for the 2015 ozone NAAQs.

Commenter (0436) explains that Utah Division of Air Quality (UDAQ) worked with the EPA Region 8 staff early and often throughout the development of Utah's SIP and submitted what they believed to be a fully approvable plan. Commenter expresses frustration that the EPA Region 8 indicated that the alternative threshold of 1 ppb was appropriate and approvable, then this option was rejected by federal EPA staff.

Commenter (0508) states that the EPA did not communicate concerns with Oklahoma's SIP development process, its reliance on the multiple EPA Memos or communicate its intent of disapproval of Oklahoma's SIP.

Response:

The EPA has addressed comments relating to the basis of its FIP authority elsewhere in this document and in Section III of the preamble. These comments generally make additional arguments opposing the EPA's SIP disapproval action and are therefore beyond the scope of this action. The EPA has provided guidance in this action on how states may successfully replace this FIP with approvable SIPs, and has provided a number of flexible alternatives for doing so. See Section VI.D of the preamble.

2.4.4 Authority with Respect to Western States

Comments:

Commenters (0436, 0509) express their concerns over the EPA's decision to include western states in the proposed FIP under the "good neighbor" provision without first considering important regional differences (*e.g.*, topography, wildfire prevalence, and altitude) and maintain that the "good neighbor" provision has historically been applied to states on the East Coast that are geographically smaller, more densely populated, and do not have similar confounding ozone.

Moreover, commenter (0436) believes that between the significant limitations in the inventory and modeling analysis this action is built on, the substantial regionally specific challenges present in the Western US, and the fact that Utah co-developed with the EPA Region 8 a fully approvable SIP, Utah should not be included in any final rulemaking associated with this FIP.

Commenter (0509) describes the topography of the state of Wyoming, and notes that for western states (*e.g.*, Wyoming), the EPA has previously evaluated good neighbor state plans using a weight of the evidence standard. In addition to a lack of adequate consultation with western states representatives, the commenter expresses their concern over the EPA's decision to include western states in the proposed FIP without performing an adequate regional analysis or having evaluated the accuracy or applicability of how its modeling, which the commenter notes, was developed for eastern states, would apply to western states. Prior to finalizing the rule, the commenter encourages the EPA to conduct substantive technical outreach with western states' air pollution control agencies.

Commenter (0436) states despite decades of success in reducing precursor emissions through regulatory actions, these regionally specific challenges have impeded progress in reducing ozone concentrations. It appears that the EPA made little to no effort to consider these unique challenges when including Utah and other Western states in the proposed action, and instead grouped states with significantly different geographic challenges together in an attempt to fulfill an agenda outside of the original intent of the good neighbor provisions of the CAA.

Commenter (0314) states EPA has determined that facilities in Wyoming are generating sufficient nitrogen oxide and VOC emissions to be significantly contributing to the state of Colorado's ability to maintain ozone air quality standards. The commenter questions whether Wyoming should have been included in the EPA's proposed action. The EPA is inappropriately implementing provisions in the Clean Air Act regarding interstate transport, specifically at 42 U.S.C. § 7506(a), which directs:

Whenever, on the Administrator's own motion or by petition from the Governor of any State, the Administrator has reason to believe that the interstate transport of air pollutants from one or more States contributes significantly to a violation of a national ambient air quality standard in one or more other States, the Administrator may establish, by rule, a transport region for such pollutant that includes such States.

Subsection (1) further delineates that the EPA Administrator may:

> add any State or portion of a State to any region established under this subsection whenever the Administrator has reason to believe that the interstate transport of air pollutants from such State significantly contributes to a violation of the standard in the transport region.

According to the commenter, if the EPA Administrator determines an upwind state is contributing to a downwind state's nonattainment, the Administrator is to create a transport region encompassing those states. In this proposed action, the EPA's models project that facilities in Wyoming are contributing to Colorado's ozone nonattainment. However, the EPA is only proposing to include Wyoming in the transport region, not Colorado. If finalized as is, Wyoming industries would be contributing to the nonattainment of a state outside of the transport region. If the EPA moves forward, according to the directive in the CAA, it would either need to remove Wyoming from this action because Wyoming is not contributing to another transport region state's nonattainment; or if the EPA retains Wyoming, it will have to include Colorado in this action in order for it to be considered part of the transport region.

Commenter (0554) declares that western states should be removed from the proposed ozone transport rule. After evaluating the proposed rule and its impacts on both EGUs and non-EGUs, the commenter has concluded that the EPA's basis for including western states in the rule is inadequately supported and that the costs and other negative impacts of including these states will far outweigh the benefits of pulling them into the proposal. According to the commenter, the proposed rule does not recognize the unique scientific considerations underpinning ozone transport in the west, nor does it account for the significant uncertainty and learning curve for sources in states that have not historically been regulated under federal NOx allowance trading programs. The commenter claims that these sources must invest substantial time and effort to prepare for compliance in only 11 months with a rule still in its formative stage (and even less time than that once the rule is finalized). According to the commenter, its analysis indicates that the stringency and timeline of the rule will introduce reliability risk in western states where there are numerous affected sources that do not currently have the kinds of controls the EPA has deemed cost-effective in its proposal. The commenter adds that the EPA's attempt to incorporate western states into the proposed rule is based on flawed modeling, the compliance timeline in the proposed rule severely limits compliance alternatives for affected EGUs, and installation of SCR technology cannot be achieved at the scale and timing required by the proposed rule. Further, the commenter declares that the EPA has proposed restrictions and limitations on the NOx allowance trading program that severely restrict, if not eliminate, market opportunities to achieve compliance. The commenter is also concerned about applying the pre-determined, one-size-fits-all CSAPR approach to western states given the administrative process EPA has employed. The commenter believes states are best positioned to provide the right solutions to ozone transport and encourages the EPA to follow the CAA procedures for states, not EPA, to act as the primary decision makers on how best to achieve the good neighbor provisions of the 2015 ozone NAAQS.

Response:

The EPA has applied the 4-step interstate transport framework across all states for purposes of the 2008 and 2015 ozone NAAQS, and its approach to western-state good neighbor obligations in this action is consistent with those prior actions.[30] The EPA has in certain circumstances in the course of those actions recognized that there may be a basis for unique treatment in relation to specific conditions that may occur in western regions of the country. For instance, we have given unique consideration to the potential for interstate transport from Colorado under wintertime inversion conditions in the Uinta Basin of Utah.[31] We have recognized in one instance that Colorado's demonstration of anomalous atmospheric conditions was informative of our evaluation of whether Wyoming should be considered linked to Colorado receptors. *See* 84 FR 3389 (Feb. 12, 2019).

However, none of those circumstances has ever led the EPA to conclude that a fundamentally different approach to ozone transport must be adopted in the west as compared to the east. The EPA deferred acting on certain western states in the CSAPR Update in recognition for the

[30] For a discussion of this history, *see* for example 87 FR at 31480-81 (proposed disapproval of Utah SIP submission) and 87 FR at 31453-56 (proposed disapproval of California SIP submission).

[31] *See* 87 FR 61249, 61254-55 (Oct. 11, 2022)

potential that there could be geographically relevant factors that may warrant a different approach in the west. 81 FR at 74523. However, at that time, the EPA offered no explanation of what those factors might be or what different approaches might be warranted. We made clear that western states may have emissions-reduction obligations under the good neighbor provision and that we would promulgate FIPs if necessary to fulfill our backstop role under the Act. *See id.*

In circumstances where the need for some unique consideration in relation to western geography was not evident, we have applied the 4-step interstate transport framework. For example, we issued a final disapproval of Utah's SIP submission as to prong 2 of the good neighbor provision for the 2008 ozone NAAQS, and in doing so responded to adverse comment to explain why our general interstate transport modeling the methodology could reliably be applied. *See* 81 FR 71991 (Oct. 19, 2016). (Utah has not to-date submitted an updated SIP submission to address this disapproval.)

The EPA finds in this action that air quality conditions and contribution from upwind states, including the problem of collective contribution, are sufficiently analogous to the regional ozone problem in the eastern U.S. that applying the same framework across all linked states is warranted and will produce a strategy that eliminates significant contribution and interference with maintenance for purposes of the 2015 ozone NAAQS.

The EPA does not agree with commenters' concerns that the modeling the EPA uses at Steps 1 and 2 to identify receptors and linked upwind states is inappropriate or unreliable for applications in the western region of the U.S. As noted, we have rejected such comments previously, *see* 81 FR 71991. *See also* 88 FR 9336, 9378-79. The EPA addresses the technical aspects of these comments in more detail in Section 3 of this document.

Finally, nothing in the Act mandates the creation of an ozone transport region under CAA section 176A as a predicate for addressing obligations under CAA section 110(a)(2)(D)(i)(I). The Administrator's authority under section 176A is discretionary, and Section 176A is an independent mechanism for addressing issues of interstate pollution transport. *See New York v. EPA*, 921 F.3d 257 (D.C. Cir. 2019) (upholding the EPA's denial of petition to expand the Ozone Transport Region in light of continued reliance on CAA section 126 and 110(a)(2)(D)(i)(I) as more appropriate mechanisms to address petitioners' interstate transport concerns).

2.4.5 New Mexico

Comments:

Commenter (0758) urges the EPA to disapprove New Mexico's submitted SIP and finalize a FIP that includes New Mexico. Commenter explains its concerns with New Mexico's SIP. The New Mexico Environment Department's (NMED's) submission is not a plan to reduce ozone-precursor emissions. Instead, it sets forth analysis purporting to demonstrate that New Mexico does not cause or contribute to nonattainment of the 2015 ozone NAAQS in any other state. The analysis is limited to considering New Mexico's impact on ozone levels in the Denver

Metro/North Front Range ozone nonattainment area. NMED acknowledges that the EPA modeling showed a contribution of greater than 0.7 ppb to the 2015–2017 DV at the Weld County monitor, and projects a contribution of 0.77 ppb in 2023; however, the agency baselessly seeks to write off its modeled significant contribution by pointing to much larger contributions from sources in Colorado.

According to the commenter (0758) NMED's analysis is deficient because it completely ignores New Mexico's contribution to ozone violations in El Paso, Texas. The EPA's modeling indicates that New Mexico is expected to contribute 1.52 ppb to El Paso's Ivanhoe monitor (monitor 481410029) and 1.67 ppb to El Paso's Skyline monitor (monitor number 481410058) in 2023. Contributions to El Paso's other monitors, many of which are reporting higher DVs than these two monitors, were not included, but are expected to be similar. While these monitors are characterized as "maintenance" receptors, El Paso County has violated the 2015 ozone NAAQS every year since 2016 and was formally designated as a nonattainment area last year. Accordingly, New Mexico is not merely interfering with maintenance of the NAAQS in El Paso—it is significantly contributing to ongoing nonattainment. Moreover, NMED's analysis also ignores New Mexico's contribution to maintenance receptors in southwest Colorado. The EPA modeling indicates that New Mexico is expected to contribute 2.74 ppb to a maintenance monitor in La Plata, Colorado. New Mexico is plainly interfering with maintenance in southwest Colorado. Given the clear evidence that New Mexico is violating the good neighbor provision, the EPA must disapprove NMED's certification and promulgate a FIP for the state. There are significant opportunities to reduce NO_X within the state. In a recent rulemaking, NMED considered adopting stringent emissions limits for four-stroke lean-burn reciprocating internal combustion engines ("4SLBs"), but ultimately adopted a standard of 2.0 g NO_X/hp-hr, which the agency's own analysis suggested almost all existing engines could meet. The standard was further weakened by the inclusion of an averaging provision, allowing operators to avoid implementing any emissions controls as long as they had enough post-2010 engines (required by the federal New Source Performance Standard to meet a standard of 1.0 g NO_X/hp-hr) to offset the emissions from older engines. Analysis from Clean Air Task Force indicated that adopting the standards proposed by the environmental coalition of 1.2 g NO_X/hp-hr would have reduced NO_X emissions by nearly 4600 tons compared with the standard ultimately adopted by NMED. This analysis likely overstated the impact of NMED's proposed rule, because it assumed that all engines would be brought into compliance with a standard of 2.0 g NO_X/hp-hr, when in fact, operators are most likely to use the averaging provision to avoid implementing any real-world emissions reductions. The EPA must adopt a FIP for New Mexico and should include standards for RICE [reciprocating internal combustion engine] in such plan."

Response:

This comment relates to New Mexico's SIP. New Mexico is not one of the states covered in this action. Further, action on the state's SIP is out of scope of this action. The EPA's findings with respect to New Mexico in the most recent modeling and our intended course of action is explained in Section IV.F.2.b.

2.4.6 Venue for Challenges to SIP Disapprovals

Comments:

Commenter (0499) comments that the appropriate venue for hearing challenges to the proposed disapproval of Louisiana's SIP is the Fifth Circuit. Commenter explains the EPA claims that the appropriate venue for challenges to EPA's final action on the interstate transport SIPs for Louisiana, Arkansas, Texas, and Oklahoma is the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). Under section 307(b)(1) of the CAA, for purposes of determining venue for challenges to EPA actions, the relevant questions are whether the action is: (1) a nationally applicable action; (2) a locally or regionally applicable action; or (3) a locally or regionally applicable action based on a determination that has nationwide scope or effect.

The commenter continues, the EPA claims that the Proposed SIP Disapproval, if finalized, would be a "nationally applicable" action under CAA section 307(b)(1) because it would address four states, located in three different federal judicial circuits, and "would apply uniform, nationwide analytical methods, policy judgments, and interpretation with respect to the same CAA obligations." EPA's reasoning is insufficient to make the final rulemaking a "nationally applicable" action and it would be inconsistent with EPA's recent final rulemaking approving the ozone interstate transport SIPs for Florida, Georgia, North Carolina, and South Carolina. Despite the fact that rulemaking applied to four states located in two different federal judicial circuits, and also relied on EPA's 4- step interstate transport framework, the EPA did not determine that action was nationally applicable, with judicial review available only in the D.C. Circuit. Instead, the EPA determined that judicial review of the rule must be filed in the United States Court of Appeals for the appropriate circuit.

The commenter states in the alternative to determining that the final rulemaking would be "nationally applicable," EPA states "the Administrator intends to exercise the complete discretion afforded to him under the CAA to make and publish a finding that the final action … is based on a determination of 'nationwide scope or effect.'" However, despite the Agency's unsupported claim, the EPA is not afforded "complete discretion" in proposing to find that the final rulemaking would be based on a determination of "nationwide scope or effect" within the meaning of CAA section 307(b)(1). Courts do not defer to EPA's determination of venue. Likewise, there is no provision in CAA section 307(b)(1) that gives EPA the exclusive authority to determine whether an action is based on a determination of nationwide scope or effect. Rather, the CAA "provides a clear metric by which a court can assess the scope or effect of the relevant determinations. The reviewing court merely asks whether the scope or effect of the determinations is nationwide.

The EPA's intent to "apply uniform, nationwide analytical methods, policy judgments, and interpretation with respect to the same CAA obligations" in this and other ozone transport SIP rulemakings would not transform any of the final rulemakings into one that is "based on a determination of nationwide scope or effect." Indeed, it would be arbitrary and capricious for EPA to apply non-uniform analytical methods, inconsistent policy judgments, and inconsistent interpretations to the various state ozone transport SIP submittals. If EPA relies on the same concept or interpretation in "other final agency action, it will be subject to judicial review upon challenge" to that separate action. In approving the interstate transport SIPs for Georgia, Florida, North Carolina, and South Carolina, the EPA relied on the same 4-step interstate transport framework on which it relied for this rulemaking, as noted above, and yet EPA made no claim that its approval of those states' SIPs was based on a determination of nationwide scope or effect, in direct contrast to this rulemaking.

Despite the EPA's claim that its final rulemaking with respect to the ozone transport SIPs for Arkansas, Louisiana, Texas, and Oklahoma will be nationally applicable or based on a determination of nationwide scope or effect, the EPA's final action on these states' SIPs will be locally or regionally applicable, and not based on a determination of nationwide scope or effect. "The question of applicability turns on the legal impact of the action as a whole." Here, the EPA's proposed action is limited to a single EPA Region and directly impacts only four states. This is the prototypical example of a regionally applicable action. Although EPA claims to be applying uniform, nationwide analytical methods, policy judgments, and interpretations, the EPA's proposed disapprovals are inherently state-specific and depend on the "facts and circumstances of each particular state's submittal." Accordingly, petitions for review of EPA's final action with respect to the interstate ozone transport SIPs may be brought only in the court of appeals for the appropriate circuit. For EPA's final action with respect to Louisiana's SIP, that will be the U.S. Court of Appeals for the Fifth Circuit."

Commenter (0501) suggests that the EPA take its time in finalizing the proposed rule and prioritize quality over meeting deadlines. Commenter suggests that efforts by the EPA to push forward a rule simply to meet deadlines will have unintended consequences that will negatively impact regulated parties and improperly shift the EPA's burden to industry. Commenter notes that rushing through the rulemaking process may also invite avoidable litigation.

Commenter (0541) writes that the EPA's action on Alabama's SIP is a locally or regionally applicable action only and is reviewable only in the appropriate regional circuit—the Eleventh Circuit Court of Appeals. Commenter explains in initially proposing approval of Alabama's SIP in 2019, the EPA correctly did not propose to find the action nationally applicable. See generally 84 Fed. Reg. at 71,854. And EPA also correctly did not propose to make a finding that its action was based on a determination of nationwide scope or effect. Id. However, in issuing its proposed disapproval, the EPA incorrectly took a different and illogical approach, proposing to make a finding that disapproving Alabama's SIP, based on Alabama-specific facts and affecting no other state than Alabama, was nonetheless based on a determination of nationwide scope or effect. 87 Fed. Reg. at 9,561. The EPA also reserved the right to issue a consolidated final action on all disapprovals, which the EPA maintained would be "nationally applicable.

The EPA's understanding of the CAA's venue provision in its proposed disapproval is flawed. See 42 U.S.C § 7607(b) (1). An action on a state's SIP is "the prototypical 'locally or regionally applicable' action that may be challenged only in the appropriate regional court of appeals." Am. Rd. & Transp. Builders Ass'n v. EPA, 705 F.3d 453, 455 (D.C. Cir. 2013). Although the EPA must be consistent in all of its actions to avoid being arbitrary and capricious, doing so does not form a basis for a finding of that an action is based on a determination of nationwide scope or effect, as it is of course "typical" for agency actions to have “precedential effect in [other] EPA proceedings,” including locally and regionally applicable actions. See Sierra Club v. EPA, 926 F.3d 844, 850 (D.C. Cir. 2019). Similarly, the EPA cannot convert a SIP approval or disapproval for a state into a nationally applicable action just by publishing it in the same document with approvals or disapprovals for other states. Any final action EPA takes with respect to Alabama’s SIP is reviewable only in the “appropriate circuit” under the CAA’s venue provision, which, here, is the Eleventh Circuit.”

Response:

These comments relate to the appropriate venue for petitions for review of the EPA’s action disapproving certain SIP submittals, which are not addressed in this action. These comments are therefore out of scope.

2.5 Rule Application and Necessary and Appropriate Finding for Indian Country

Comments:

Commenters (0257, 0259, 0402) support the proposed rule's strengthening and expansion of interstate transport ozone obligations. The commenters agree with the EPA 's decision for the proposed rule to be applicable in Indian country, as the commenters believe this will avoid a situation that creates incentives to site ozone precursor emitting facilities in Indian Country to avoid installing or operating pollution control equipment. The commenters also recommend that the EPA provide assistance to and work with Indian Tribes that express interest in administrating a tribal plan to implement the good neighbor provision, noting that even Tribes that do not currently have an affected source may still wish to administer such a plan.

Commenter (0378) states that the EPA should remove the Uintah and Ouray Reservation and the Bonanza Power Plant (BPP) from the Good Neighbor Rule (GNR) applicability. According to the commenter, the very significant benefit of ensuring a reliable electrical supply large enough to serve the oil and gas industry in the Uintah Basin (UB) far outweighs the tiny incremental benefit to downwind Colorado ozone of adding controls to the BPP. The commenter claims that the EPA is not bound by any precedent to include the BPP in the GNR. The commenter says that although the decision to make the necessary and appropriate finding to include Indian country in the GNR was consistent with other GNR rulemakings, no other existing units were located in the covered areas of Indian country at the time of promulgation. According to the commenter, the BPP is uniquely situated among the current and all prior GNR rulemakings as an existing EGU located in Indian country and subject to controls upon promulgation of the final GNR, and as such, the EPA has no precedential obligation to include the BPP in this rule.

Furthermore, the commenter (0378) states that in making the necessary and appropriate finding to include the BPP in the good neighbor rule, the EPA’s assessment overlooked critical information about the Uintah and Ouray Reservation. The commenter claims that requiring costly emissions controls on the proposed overly aggressive schedule could jeopardize the reliability of the full electricity supply in the UB ozone nonattainment area, which poses a trade-off between ozone pollution within the UB and downwind ozone in Colorado. The commenter states that the EPA must assess this tradeoff and make an informed decision on whether to include the BPP in the GNR-required controls. The commenter provides background on the BPP, noting that it is located within the UB ozone nonattainment area, designated under the 2015 ozone standard. The commenter notes that the UB incurs rare wintertime ozone, produced from local oil and gas operation emissions under specific conditions when atmospheric inversions occur at times of significant snow cover on the ground. The commenter also notes that most oil and gas sites in the UB do not have access to electricity and therefore rely on raw natural gas to power generators, engines, and pneumatic controllers and pumps, which causes significant VOC emissions. According to the commenter, research shows that reducing VOC emissions in the UB would reduce ozone, but the lack of available electricity throughout the UB stands in the way of electrifying oil and gas production sites and reducing VOC emissions. The commenter notes that according to the UB Electrification Study, electrification of the oil and gas operations in the UB could have a tremendous effect towards reducing ozone concentrations in the UB, reducing peak ozone in February 2019 from about 110 ppb to about 82 ppb. The commenter adds that any control requirements for the BPP that could potentially reduce the electricity supply or reliability would be detrimental to ongoing efforts to expand the electricity supply and distribution to the oil and gas industry throughout the UB. The commenter also adds that the Deseret Electric Cooperative (which relies on power produced by the BPP) identifies the BPP as one of the top environmentally clean coal-fired power plants in the United States, suggesting that these controls may not be necessary. According to the commenter, the downside of control requirements of the GNR on BPP would have a detrimental effect on the electrical power supply in the UB, which would far exceed the benefit to ozone downwind in Colorado. The commenter concludes that in light of the BPP being uniquely situated among EGUs in Indian country nationwide, removing BPP applicability from the GNR would not pose an equity concern to other facilities and could easily be justified. In addition, the commenter adds that the tradeoff issue described above serves to discredit the proposed “necessary and appropriate” finding. Further, the commenter states that BPP controls could have the environmental justice impacts by standing in the way of reducing ozone concentrations on the Uintah and Ouray Reservation. Finally, the commenter states that the EPA’s necessary and appropriate finding analysis should consider, first and foremost, how to achieve the greatest ozone reductions wherever they may be, and that the finding applicable to the BPP would not be supported in this case. Therefore, according to the commenter, the EPA must remove the BPP applicability from the GNR.

Commenter (0532) questions whether the EPA has the authority to include the BPP in Utah’s plan. The commenter remarks upon the EPA’s statement that its inclusion of an existing EGU in Indian country not covered by a state’s CAA implementation planning authority is “necessary and appropriate… to address the interstate transport of ozone on a national scale” and is a “similar approach… to prior CSAPR rulemakings” by asserting that this statement falls far short of an adequate procedure that would need to precede the inclusion of any EGU in Indian country within this or a similar rulemaking. The commenter submits that the proposed rule is arbitrary and in violation of the APA because it is acting in absence of appropriate regulatory procedure or authority to regulate air quality in Indian country without express authorization and direction from Congress to aggregate those sources with other sources within the geographic boundary of a state. The commenter adds that the EPA has already entered a settlement agreement with Bonanza on NO_X emissions through a MNSR process in accordance with a 301(d) FIP area, and due to the lack of evidence that the APA would allow Indian country to be included in the jurisdiction of a state, it would be inappropriate to now include the BPP in this rule. The commenter also claims that the EPA has made no attempt to identify, quantify, or analyze the effect, if any, of Indian country sources on any nonattainment within any downwind state. The commenter adds that until such analysis is undertaken and made publicly available, an announcement of any regulation is arbitrary and without an adequate basis to conclude that it is either necessary or appropriate to burden sources in Indian country as part of any program for cross-state emissions. The commenter notes that the EPA has not attempted to develop regulations for Indian country sources, which is why the EPA previously excluded BPP from the Regional Haze program.

Commenter (0532) believes that the EPA should exclude the Bonanza plant from the transport rule, considering prior agreements with the EPA and its approved minor new source review (MNSR) for its low NO_X burners. The commenter provides background information about the Bonanza plant, including that the EPA approved the commenter's 2015 application for a MNSR, which authorized the replacement of the existing LNBs at Bonanza with new LNBs, along with installing overfire air systems to reduce NO_X emissions. The commenter notes that these overhauls were part of a settlement agreement negotiated between the commenter, Sierra Club, Wild Earth Guardians, and the EPA ("Agreement"). The commenter adds that the MNSR required Bonanza to not discharge into the atmosphere NO_X in excess of 0.28 lbs/MMBtu heat input, based on a 365-boiler operating day rolling average, or 5,700 tpy on a rolling 12 calendar month basis. The commenter states that the EPA has provided no evidence or justification that Bonanza has not complied with these standards or that these MNSR standards are insufficient for NO_X compliance in the Uintah Basin. The commenter adds that the MNSR established future reductions at Bonanza that were "to not exceed 3,000 tpy on a rolling 12 calendar month basis after January 1, 2030," and the commenter believes this MNSR has laid out the NO_X compliance parameters for the present and future operations at Bonanza. According to the commenter, another critical component of the MNSR is that it incorporated a coal consumption cap at Bonanza that began in 2020 and extends through the end of service of the Bonanza unit. That Cap is not to exceed 20,00,000 short tons of coal consumed at the plant, unless, as the Agreement states, the commenter installs a SCR before December 31, 2029. The commenter believes this agreed-upon date provides the commenter with a more reasonable timeline to install an SCR, if they choose to do so, than the proposed rule. According to the commenter, expediting the timeline as the rule proposes could force the commenter into financial uncertainty because of the reliance and planning it has undertaken with the MNSR.

Response:

The EPA disagrees with commenters that the Bonanza Power Plant (BPP) should be excluded from the final rulemaking. The BPP is an EGU source located on the Uintah and Ouray Reservation, geographically located within the borders of Utah. As described in Section III.C.2 of the preamble, the EPA has evaluated the applicability of this rule to areas of Indian country under CAA section 301(d)(4) and 40 CFR 49.11(a), and determines that implementation of the rule's requirements is warranted. Under this "necessary and appropriate" finding, the rule is applicable in all areas of Indian country (as defined at 18 U.S.C. 1151) within the covered geography of this rulemaking. As further described in Section III.C.2 of the preamble, this determination is consistent with prior rulemakings under the good neighbor provision, including CSAPR, the CSAPR Update, and the Revised CSAPR Update, which included areas of Indian country within the EGU trading program FIPs and would have subjected any EGU sources located in those areas to the trading program, just as the EPA is requiring in this rule.

Commenter's claim that this rule violates the APA or otherwise is procedurally improper, is incorrect, and otherwise is unsupported and lacking in reasonable specificity. This is a notice-and-comment rulemaking action that is in compliance with the CAA and the implementing regulations for areas of Indian country under 40 CFR part 49. This is not the EPA's first regulation of existing sources of air pollution under CAA section 301(d) and part 49. In fact, the EPA recently promulgated a FIP regulating emissions from oil and natural gas sources on the Uintah and Ouray Reservation. 87 FR 75334 (Dec. 8, 2022). The EPA acknowledges that it has not reviewed the Bonanza plant under the first planning period regional haze program, but this could be because Bonanza is not a BART-eligible source and addressing BART sources was an important focus of the first planning period. Further, the EPA continues to review regional haze obligations under the reasonable progress portion of the regional haze program for the second planning period. The EPA cannot provide comment at this time on Bonanza with respect to those obligations as this topic is beyond the scope of this action. The EPA has previously regulated other EGUs on Indian country under the regional haze program. *See, e.g.,* 79 FR 46514 (Aug. 8, 2014).

Additionally, while the EPA acknowledges that the BPP is subject to other regulatory programs and agreements, the agency disagrees that these agreements should exclude the facility from this rulemaking. The EPA notes that every EGU has its own unique regulatory and permitting history in relation to other requirements under the CAA. The EPA does not consider a facility to be exempt from this rulemaking just because the facility may be subject to other regulatory requirements and agreements. While there is nothing specific in the comments regarding Bonanza that suggest that this plant should uniquely qualify for different treatment than other EGUs in this regard, we note that we have adjusted the final rule from proposal in several ways that will facilitate compliance and flexibility in ways that could be of use to Bonanza and consistent with its pre-existing regulatory obligations. For instance, the backstop daily emissions rate will be deferred to as late as 2030 for EGUs that do not currently have SCR installed, to allow for utility planning around EGU retirements and fleet transition.

In regard to the comment that implementation of the rulemaking could jeopardize the reliability of the electricity supply in the Uintah Basin ozone nonattainment area, the EPA notes that EGUs subject to this rulemaking will be included in a trading program. The budgets that are established for the EGUs in the trading program are premised on retrofitting SCR for coal-fired EGUs such as Bonanza. The trading program is discussed in more detail in Section VI.B.1 of the preamble. BPP could comply with the rule through the installation of pollution controls while continuing to operate. Further, since the control stringency is implemented through mass-based allowance holding requirements, BPP is also free to pursue other means of compliance. If Bonanza were to continue operating with SCR installed as its method of compliance, this would reduce its own ozone-precursor emissions without undermining the goal commenters mention of electrification of the local oil and gas wells to reduce ozone-precursor emissions from those sources. The EPA notes that nothing in this FIP prevents the advancement of electrification through other sources of generation such as renewables or natural gas, which would likely have much lower NO_X emissions than a coal-fired EGU like BPP.

3 EPA's Analysis of Downwind Air Quality Problems and Contributions from Upwind States

3.1 Years Selected for Analysis

Comment:

Commenters (0405, 0437) comment that the proposed rule inappropriately shifts the burden of additional controls to upwind states. Commenter (0405) elaborates that the EPA imposes "significant and unnecessary emissions reduction obligations…without consideration of expected emissions reductions from downwind states who are choosing to delay implementation requirements. The commenters allege that this is in direct contravention of the D.C. Circuit's remand of *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019), which the commenters characterize as directing the EPA to ensure that upwind and downwind states are on parallel paths with respect to air quality attainment deadlines.

Commenter (0416), in general, claims that the EPA's transport rule has no consideration for implementation of nonattainment controls by downwind states which they characterize as the EPA effectively shifting the burden of additional controls to the upwind states. The commenters allege that the EPA has a duty to delay the upwind compliance date to align with the downwind state compliance deadlines. According to the commenters, both plans must be aligned with the same timeframes to avoid an inappropriate shifting of the compliance burden from one group of states to another. Commenter (0528) argues that upwind states cannot know what their good neighbor obligations are until after the level of air pollution in downwind states is known, citing *EME Homer City I* (a D.C. Circuit case that was overturned by the Supreme Court in *EME Homer City*). The commenter argues that it is arbitrary and capricious for the EPA to "determine upwind state contributions without accounting for downwind state controls that will be put in place after summer 2021." The commenter also argues that "it is unreasonable for EPA to require upwind states to act before downwind states and to assess contribution to nonattainment before all downwind controls are assessed" and that doing so may result in over-control. The commenter also argues that "it is arbitrary for EPA to effectively require upwind states to implement controls by the 2023 ozone season, a year prior to the attainment deadline."

Commenter (0342) states the EPA's proposed FIP fails to consistently implement requirements between geographic regions. Upwind states should not bear the burden of early control deadlines while downwind states are granted additional time. The EPA is required under the CAA to consider the effects of local emissions before seeking controls in upwind states. If any facilities are required to install additional controls, downwind and upwind states should be required to do so at the same time if the modeling supports such changes.

Commenter (0323) says that the EPA's selection of 2023 as the analytical year for its assessments of the state plans fails to align the obligation of upwind states with downwind states inasmuch as certain nonattainment areas have delayed implementation of nonattainment controls until 2025 and beyond. [The remainder of this comment excerpt is from commenter (0323) with minor formatting changes:]

The EPA's statutory duty is to synchronize the "good neighbor" provision of the CAA, section

110(a)(2)(D)(i), with nonattainment and maintenance requirements of CAA including §172 such that compliance burdens are mutually and equitably aligned among upwind and downwind states. The Midwest Ozone Group (MOG) is not offering comment on the downwind state plans for emissions reductions strategies provided the responsibility of upwind states under the good neighbor provisions of the CAA are timed to coincide with the responsibility of downwind states to implement nonattainment controls. In the case of the proposed rule, however, the EPA has failed to address the timing of the implementation of upwind controls relative to downwind controls thereby causing unnecessary and excessive emissions controls to be required by the upwind sources. The EPA's failure to comply with the CAA obligations to align upwind and downwind control obligations is compounded by the fact that the EPA delayed disapproving upwind state good neighbor plans far beyond the two years specified in the CAA for such action. The proposed disapprovals and FIP presume the significant contribution should be calculated without consideration of the downwind state delay in implementing emissions reductions and the effect on ozone concentrations, thus shifting a burden of otherwise unnecessary additional controls to the upwind states. The CAA, however, directs synchronization/alignment of upwind and downwind emissions reduction requirements. Synchronization as applied means if a downwind state delays action, then the upwind state would accordingly take good neighbor action on a schedule that mirrors the downwind implementation strategy. To accomplish this emissions control program any other way means that either the upwind or downwind state could be obligated to implement emissions control far beyond what they otherwise might have to implement as part of a synchronized/aligned program.

Historically, the EPA has assessed the impact of state emissions reductions programs on ambient air quality in the applicable future analytic year by first determining the extent to which existing "on-the-books" regulatory programs could be expected to improve ambient air quality. The EPA has noted its modeling assessment generally accounts for enforceable "on-the-books" emissions reductions and provides the most up-to-date forecast of what future emissions would resemble, but the EPA has departed from a comprehensive modeling assessment in the proposed rule under evaluation. 87 FR 20054. For this proposed rule, emissions inventories were developed for the years of 2016, 2023, 2026, and 2032 that represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions, controlled installations, and promulgated federal measures that affect anthropogenic emissions. The EPA contends that its projected base case accounts for the effects of on-the-books federal and state rules through early 2021. *Id*. at 20,063. Of concern to MOG is the failure of the EPA to consider emissions control programs adopted after early 2021 that should be assessed for impact on nonattainment and therefore upwind significant contribution. With ongoing efforts to manage and balance timely programs directed at nonattainment in upwind and downwind states, it is objectionable that there are no provisions for consideration of enforceable programs that will impact compliance with the NAAQS after "early" 2021. It is also a matter of concern that the EPA analysis was based upon the air quality modeling undertaken in connection with the Revised CSAPR Update[3] which includes an outdated emissions inventory that does not account for any on-the-books control programs adopted after 2019 nor does it reflect the updated emissions inventory that was used by the EPA to assess Step 1 and 2 issues in connection with the current proposal.[4]

The EPA has failed to discharge its responsibility under the CAA to harmonize the parallel timing and therefore collective impact of both upwind and downwind SIPs. The *Wisconsin* remand concluded that the EPA exceeded its statutory authority under the good neighbor provision "by issuing a rule that does not call for upwind States to eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines." *Wisconsin v. EPA*, 938 F.3d 303, at 318. The *Wisconsin* remand directed EPA to address the downwind state "deadline" in such a manner as to "harmonize" the deadlines of upwind and downwind states and to apply "parallel timeframes." *Id.* at 312, 314. The D.C. Circuit repeatedly has explained the CAA directive to "harmonize" and manage the relationship described as parallel between the good neighbor obligations for upwind states and statutory attainment deadlines for downwind areas. That relationship is one of "par," using the Court's term, meaning to be judged on a common level with the other.[5]

With this proposal, the EPA ignores the obvious relationship between the downwind states' obligation to implement controls to attain the standard relative to the obligation of an upwind state to not significantly contribute to the nonattainment at issue. The EPA has been directed by the D.C. Circuit to fashion its transport rules deadlines to coordinate with downwind states deadlines, in concert with one another. The D.C. Circuit found error in the EPA's historic transport rule, CAIR, in which the EPA did not explain why it did not coordinate the good neighbor provision with CAIR to provide a sufficient level of protection to downwind states. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). Despite the CAA section 110(a)(2)(D)(i) requirement that upwind contributions to downwind nonattainment be "consistent with the provisions of [Title I]," EPA did not make any effort to *harmonize* CAIR's Phase Two deadline for upwind contributors to eliminate their significant contribution with the attainment deadlines for downwind areas. . . . As a result, downwind nonattainment areas must attain NAAQS for ozone

and $PM_{2.5}$ without the elimination of upwind states' significant contribution to downwind nonattainment, forcing downwind areas to make greater reductions than CAA §110(a)(2)(D)(i)(I) requires. *Id.* (emphasis added). The D.C. Circuit described its *North Carolina* ruling in the *Wisconsin* remand as follows:

> We explained that EPA needed to "*harmonize*" the "Phase Two deadline for upwind contributors to eliminate their significant contribution with the attainment deadlines for downwind areas." . . . Otherwise, downwind areas would need to attain the NAAQS "without the elimination of upwind states' significant contribution.
>
> *Wisconsin*, 938 F.3d at 314 (emphasis added).

The *Wisconsin* remand explained, "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." *Id.* at 315 (emphasis added). The *Wisconsin* opinion explains further:

> The Good Neighbor Provision, as *North Carolina* emphasized, requires upwind States to eliminate their significant contributions to downwind pollution "consistent with the provisions of this subchapter," *i.e.*, Title I of the CAA. 42 U.S.C. §7410(a)(2). One of the "provisions of this subchapter" is §7511(a)(1), which in turn requires downwind areas in

moderate non-attainment to attain the NAAQS by July 20, 2018.

Id. at 315-16.

The *Wisconsin* remand summarizes that "it is the statutorily designed relationship between the good neighbor provision's obligations for upwind states and the statutory attainment deadlines for downwind areas that generally calls for parallel timeframes." *Id.* at 316. Simply put the obligation to coordinate cuts both ways. Upwind and downwind obligations must have view of what each is required to accomplish and coordinate the implementation plans accordingly.

The EPA offers its implementation timing interpretation of the D.C. Circuit court's holding in *Maryland v. EPA*, 958 F. 3d 1185 (D.C. Cir. 2020) as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date, which is now the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 8-hr ozone NAAQS is August 3, 2024. The EPA states that it believes 2023 is now the appropriate year for analysis of interstate transport obligations for the 2015 8-hr ozone NAAQS because the 2023 ozone season is the last relevant ozone season during which achieved emissions reductions in linked upwind states could assist downwind states with meeting the August 3, 2024, Moderate area attainment date for the 2015 8-hr ozone NAAQS. 87 Fed. Reg. at 20,099. By selecting 2023 for analysis, the EPA is inappropriately shifting the burden to the transport states because it is not similarly requiring downwind states to have their controls effective by that date as well.

The EPA recently demonstrated its improper interpretation of the process disconnect between standards to which downwind plans are held versus the standards to which upwind plans are held in its proposed denial of transport plans in February of 2022. The MOG asserts that the law provides both plans must be aligned with the same timeframes and that the obligations are simultaneous. The EPA attempts to provide justification for the disapproval of the New York transport plan due to delayed controls as follows:

> . . . under the *Wisconsin* decision, states and the EPA may not delay implementation of measures necessary to address good neighbor requirements beyond the next applicable attainment date without a showing of impossibility or necessity. *See*, 938 F.3d at 320. In those cases where the measures identified by the State had implementation timeframes beyond the next relevant attainment dates the submission did not offer a demonstration of impossibility of earlier implementation of those control measures. Similarly, the State's submittal is insufficient to the extent the implementation timeframes for identified control measures were left unidentified, unexplained, or too uncertain to permit the EPA to form a judgment as to whether the timing requirements for good neighbor obligations have been met.
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> 87 Fed. Reg. 9,494. (Emphasis added.)

As noted in MOG's April 25, 2022, comments to the proposed New York and New Jersey SIPs denials, downwind states and regulated entities are on an ever-changing path to manage the complex implementation of emissions reductions programs to address local and regional air quality impacts. The air quality modeling relied upon for these proposals fails to provide a wholistic assessment of all emissions control requirements. The following quote illustrates the missed timely air quality improvement opportunity:

> The New York State Department of Environmental Conservation ("NYDEC") has developed recent controls for simple cycle and regenerative combustion turbines ("SCCT") or "peaking units" noted by the agency as being inefficient and approaching 50 years of age. Yet, while the agency has estimated controls will result in a 4.8 ppb significant air quality improvement to nonattainment monitors within the New York Metropolitan Nonattainment Area (NYMA), implementation is delayed until 2025 and beyond. NYDEC also recently has imposed NO_X controls on distributed generation units, which as with peaking units, has been structured to delay implementation of controls beyond the applicable attainment date as part of the attainment plan proposed for approval by EPA.

87 FR 4530 (Jan. 28, 2022).

On June 2, 2022, the EPA promulgated a final rule concerning the New York ozone control SIP strategies, particularly with regard to Title 6 of the New York Code of Rules and Regulations, Part 2219, "Incinerators", and Part 222, "Distributed Generation Sources". 87 FR33438 (June 2, 2022). Responding to comments raised by MOG about the poor timing of controls relative to an attainment strategy, the EPA offered its action was "not intended to satisfy specific nonattainment planning obligations" nor interstate transport obligations demonstrating the agency's failure to realize the implementation planning provisions of the CAA all fall within the same CAA section 110 of part D addressing Plan Requirements for Nonattainment Areas. *Id.* at 33,439. The EPA offers this statement of response: "EPA acknowledges that the State of New York has unmet attainment planning obligations for the NYMA nonattainment area." *Id.* It remains a concern that the EPA approves delay of much needed emissions reductions within the NYMA while proposing good neighbor emissions reductions that fail to align upwind and downwind obligations on the same coordinated schedule.

Delayed implementation of emissions reductions programs that impact attainment must be reviewed when determining an upwind state has failed its good neighbor obligation. In the example quoted above the downwind state New York has not timely implemented controls designed to effect ozone air quality improvement. The CAA does not contemplate only looking to upwind states to resolve the New York nonattainment when New York has failed to act. It is more appropriate to align the implementation date of the New York emissions program with the upwind state good neighbor emissions program.

This issue of imbalance specifically was addressed by D.C. Circuit in the *Wisconsin* remand as an appropriate basis for extending the compliance deadline for upwind states. In the *Wisconsin* opinion the Court stated: "if a modified attainment deadline applies to downwind States, the EPA may be able, if justified, to make a corresponding extension for an upwind State's good neighbor obligations." *Wisconsin*, 938 F.3d at 317.

The EPA's proposal does not recognize the corresponding alignment obligation as articulated in the *Wisconsin* remand. The omission creates a fatal flaw in the proposal rendering it unlawful, arbitrary and capricious. The EPA's calculated upwind state contribution that does not assess downwind contribution demonstrates the failure to harmonize the two because the relationship between the upwind and downwind emissions obligations is in concert, with both impacting air quality simultaneously. The contribution calculated for upwind states changes as downwind states eliminate their contribution to nonattainment and maintenance. As downwind states reduce their contribution, the amount of emissions reductions necessary to eliminate the upwind states contribution necessarily decreases. Neither contribution can be addressed in a vacuum as the EPA is attempting to do in this proposed rule.

Response:

These comments are responded to in Section IV.A of the preamble. The EPA emphasizes here again that the commenter misinterprets the D.C. Circuit's holdings in *North Carolina*, *Wisconsin*, and *Maryland*, which held that the EPA and the states must align good neighbor obligations to the extent possible with the downwind areas' attainment dates. The attainment dates are set by the statute in CAA section 181 and remain fixed regardless of whether downwind areas are delayed in implementing their own obligations. It would be unworkable to expect that upwind states' obligations could be perfectly aligned with each downwind area's actual timetable for implementing the relevant emissions controls, and no court has held that this is the EPA's or the states' obligation under the good neighbor provision. Further, this ignores the fact that upwind states must also address their interference with maintenance of the NAAQS, as well as the *Maryland* court's holding that good neighbor obligations should be addressed by the Marginal area attainment date for ozone under subpart 2 of part D of title I of the CAA.

The Agency's air quality modeling for good neighbor purposes takes account of all known, on the books emissions controls that will be in effect in the relevant analytic year. However, requiring good neighbor obligations to be deferred until downwind emissions reductions are in fact implemented or air quality conditions are known with even greater certainty would be contrary to the statutory process for SIP development. Area designations occur two to three years after promulgation of a new or revised NAAQS pursuant to CAA section 107(d)(1)(B)(i). State SIP submissions pursuant to CAA section 110(a)(1) and (2), including good neighbor SIPs, are also due three years after promulgation of a new or revised NAAQS. Attainment plans for those areas designated nonattainment are due between 18 months and four years after designation, depending on the pollutant, pursuant to the requirements of subpart D of title I of the CAA. Redesignations, including application of the requirements of CAA section 175A to develop a maintenance plan, by definition, occur after the initial designation and frequently well after the development and submission of the state's attainment plan. Given that the statutory timeframe for development of the good neighbor SIP requires submission before the downwind state's development of an attainment plan, before an area is likely to be re-designated from nonattainment to attainment (with the attendant maintenance plan obligations), and in some cases before or at the same time designations for a new or revised standard might be finalized, the EPA does not believe it is reasonable to interpret the good neighbor provision to make states' emissions reduction obligations dependent on either current or prior designations of downwind areas with potential air quality problems in other states.

The EPA held this position in the CSAPR Update, and this is not a new interpretation of how the Act is structured. *See, e.g.*, 81 FR at 74517. However, the *Maryland* court subsequently reinforced this understanding in holding that good neighbor obligations must be addressed by the Marginal area attainment data under CAA section 181. The court explained that there is no disconnect in the timing of that obligation on upwind states with the obligations faced by downwind areas. The absence of specific, enumerated emissions-reduction requirements from existing sources in Marginal ozone nonattainment areas does not mean the downwind state does not have a statutorily binding obligation to attain and maintain the NAAQS subject to burdensome regulatory consequences: “Delaware must achieve attainment ‘as expeditiously as practicable,’” and “an upgrade from a marginal to a moderate nonattainment area carries significant consequences . . ..” *Maryland*, 958 F.3d at 1204.

3.2 Modeling Platform

3.2.1 Air Quality Model

Comments:

Commenter (0301) argues that the EPA determined through its modeling efforts that 23 states exceed the contribution threshold and are to be incorporated into the CSAPR program. The commenter alleges this was done despite work by other organizations (*e.g.*, Lake Michigan Air Directors Consortium (LADCO), MOG) which the commenter alleges shows the EPA's model inaccurately estimates the contribution from 23 states upon downwind ozone concentrations at maintenance or non-attainment receptor sites near Lake Michigan. According to the commenter, most of these upwind states have either conducted their own modeling or leveraged outside consultants to conduct extensive modeling analysis, which incorporated the region-specific geography and meteorology to reach informed, data-driven conclusions which directly contradicts EPA's conclusions in this proposal. According to the commenter, given the disagreement in modeling analysis performed by 23 states versus that performed by the EPA, the commenter believes it is reasonable to request that time be given to allow states to examine and comment upon the modeling that was conducted by the EPA, engage the EPA in meaningful discussion on discrepancies in the data, and for the EPA to remodel those impacted states after correcting the errors, and inaccuracies that the commenter alleges may have falsely led to the conclusion that a state exceeded the contribution threshold.

Commenter () believes that the modeling completed by the EPA did not appropriately account for existing emissions reductions in Minnesota and for other modeling issues that would have demonstrated that Minnesota should not be included in the proposal. Most upwind states have either conducted their own modeling or leveraged outside consultants to conduct extensive modeling analysis, which incorporated the region-specific geography and meteorology to reach informed, data-driven conclusions which directly contradicts EPA's conclusions in this proposal.

Commenters (0372, 0394, 0398, 0411, 0517, 0764, 0798) believe the EPA’s modeling platform includes numerous errors that could have been avoided with a proper stakeholder process.

Commenter (0398) argues an empirically sound model run of the scale needed to assess the question of linkages and significant contributions nationwide would take the EPA well over a year to perform, and more likely than not, would require two or more years to complete, simply because of the magnitude of a dataset and preprocessing that would be required for assessing individual impact all United States sources of ozone precursors. The commenter alleges this is another instance in which states are in a far better vantage point to perform modeling or further analysis that is specific to that state's sources; by breaking up the U.S. dataset into state-sized datasets, modeling can be performed faster, with better Quality Assurance/Quality Control (QA/QC) of data inputs, more completely, and with more accurate outcomes than the EPA's hurried version (backed by loose assumptions and ballpark estimations). According to the commenter, crafters of the CAA understood the limitations of a federal agency to address state-level pollution, and that states have the ability to focus resources on specifics; this gives further justification for the EPA to allow states to develop and implement air pollution control programs, rather than encroach on the states' responsibilities and authorities.

Response:

The EPA disagrees with these comments.

Although the EPA's action on good neighbor SIP submissions for the 2015 ozone NAAQS is out of the scope of this action, to the extent commenter 0301 is arguing that 23 alternative modeling runs casts doubt on the EPA's modeling supporting this rule, the EPA disputes the claim.

First, the assertion that 23 states independently prepared or commissioned modeling is factually incorrect. Two states covered by this rule, Pennsylvania and Virginia, did not submit good neighbor SIP submissions for the 2015 ozone NAAQS and did not present the EPA with alternative modeling. Wisconsin examined no modeling of any kind in its 2015 ozone NAAQS good neighbor SIP submission. Of the other states included in this rule, ten states relied on EPA modeling in their SIP submissions for the 2015 ozone NAAQS (Alabama, Arkansas, California, Louisiana, Maryland, Mississippi, Minnesota, Missouri, Nevada, Oklahoma, and Utah). And, although the EPA is not including Delaware, Tennessee or Wyoming in this final rule, all three of those states relied exclusively on EPA modeling in their SIP submissions as well. Between the remaining ten states included in this final rule, five alternative versions of modeling were presented to the EPA: Alpine Geophysics, Lake Michigan Air Directors Consortium (LADCO), Maryland Department of the Environment, Ozone Transport Commission, and TCEQ.

Second, the five alternative modeling runs in general do not support wildly different conclusions regarding linkages to receptors than the EPA's modeling. The alternative modeling provided by all but one of these ten states identified that the state will contribute above 1 percent of the NAAQS to one or more downwind receptors (Illinois – LADCO; Indiana – LADCO; Kentucky – Alpine Geophysics; Michigan – LADCO; Ohio – LADCO; New Jersey – Ozone Transport Commission; New York – Maryland Department of the Environment; Texas – TCEQ; West Virginia – Alpine Geophysics). The exception is Minnesota.

At this time, the EPA's 2016v3 modeling is the most up to date and scientifically robust modeling of interstate transport of ozone in the continental United States available. As discussed in Section IV.B. of the preamble, the EPA has updated its air quality modeling for this final rule in response to comments on the modeling used for proposal. As discussed below in Section 3.2.2 (Spatial Resolution and Model Performance), the EPA compared model performance from its final rule modeling to model performance from modeling performed by certain states and found that the EPA's modeling performs as well as, or better than, modeling by those states. Comments related to the EPA's model performance around Lake Michigan are addressed in Section 3.2.2 (Spatial Resolution and Model Performance).

In response to comments suggesting that the EPA's modeling is flawed for lack of public input, the EPA disagrees with the claim. The EPA has continually leveraged public input to improve the modeling used to support its assessment of good neighbor transport obligations for the 2015 ozone NAAQS (and for earlier NAAQS). For the 2015 ozone NAAQS, this process started with the release of a NODA in January 2017 and continued through the comment period of this action, as detailed in the preamble in Sections II.C. and III.A. The 2016v2 emissions modeling files have been available for comment since September 2021,[32] and the meteorological data has been available as used in the 2016v1 platform since October of 2020 (with the release of the proposed Revised CSAPR Update). The development of the 2016v2 emissions inventories that were the basis of the proposal for this action is described in 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 Modeling TSD. By providing the modeling platform on September 20, 2021, requesting that comments be provided to the EPA's emissions modeling group by December 17, 2021, and also providing ample time for comment on the proposals throughout 2022, the EPA gave stakeholders and interested parties sufficient opportunity to review and comment on the data used to develop the 2016v2 modeling.

The EPA incorporated public comments received on proposals related to 2015 ozone NAAQS interstate transport to update its emissions inventories and other model inputs, some examples of which are detailed in Section 3.3 (Emissions Inventory Data Used in Modeling) of this document. The final rule modeling using the 2016v3 platform was performed using updated emissions projections, and includes additional emissions reductions for EGUs, more recent information on plant closures and fuel switches, and other sector trends. The construct of the updated emissions platform is described in the 2016v3 Emissions Modeling TSD contained in the docket of this rulemaking. The final rule modeling additionally took into consideration feedback from commenters to improve overall model performance. Thus, by using the updated modeling results based on the new 2016v3 platform, the EPA appropriately took commenter feedback into consideration when finalizing this rulemaking and used the most current and technically appropriate information to do so.

Comments related to the length of the comment period are addressed in Section 10.1, and comments related to interpretations of the CAA and cooperative federalism are addressed in Section 1 and 2.4 of this document.

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

3.2.2 Spatial Resolution and Model Performance

Comments:

General Concern with Spatial Resolution

Commenter (0518) states the EPA's analysis of significant contribution at Step 2 is based on an inflated upwind state contribution to downwind receptors. The commenter alleges that the EPA's use of coarse grid resolution and coarse grid meteorological inputs understated ozone contributions due to local sources, which led to an overstated upwind contribution to downwind receptors.

Commenters (0317, 0323, 0331, 0359, 0365, 0394, 0395, 0405, 0416, 0436, 0437, 0499, 0509, 0531, 0539, 0547, 0554, 0760) believe the EPA's modeling has failed to capture the unique meteorological conditions caused by land-water interfaces. The commenters argue this can be remedied by using a finer grid than the one chosen by the EPA. Commenter (0554) adds this error is one reason that states are better suited to determine appropriate measures to address impacts on neighboring states. Commenter (0323) explains photochemical modeling along coastlines is complex for two reasons. First, the temperature gradients along land/water interfaces can lead to localized on-shore/off-shore flows; and secondly, the photochemical model formulation spreads the emissions in a grid cell throughout the full grid volume of the cell. Some commenters add while the use of a 12 km domain may be appropriate in portions of the eastern US, this resolution is too coarse to accurately model the complex topography that dominates western landscapes and especially those in the Intermountain West. As a result, it is unlikely that any modeling effort performed in the western US using a 12 km domain will adequately capture transport.

Commenters (0323, 0331, 0395) reference the EPA's own ozone attainment modeling guidance stating "[t]he most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for both ozone and $PM_{2.5}$ and regional haze. The commenters argue if model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s)."

General Concern about Model Performance

Commenters (0323, 0352, 0531, 0764) express concerns about the modeling conducted by the EPA in support of the proposed rule, calling it "inaccurate" and "problematic that EPA still relies on modeling to determine downwind receptors." Commenter (0764) further argues that "the significant amount of unpublished modeling data… renders EPA's modeling results un-reproducible by affected states and parties." Commenter (0531) also expresses concern that the

EPA "relies on a single 20-year-old study and ignores scientific studies conducted in 2017 and 2018… [and] relies on models using the same flawed assumptions that are unreliable and which recent studies show are not able to characterize and reproduce the ozone and precursor data collected in these recent studies."

Specific Comments on Spatial Resolution

Modeling of the Lake Michigan Area

Commenters (0331, 0394, 0395, 0539) say the 2016v2 platform performed poorly on high ozone days in the Great Lakes region. The commenters state that a finer resolution grid would be needed to fully resolve the atmospheric features in these complex regions and to model the large ozone gradients that can occur along the Lake Michigan shoreline. Commenters (0331, 0539) specify on Page 14 of the Alpine report, the 2017 Lake Michigan Ozone Monitoring Study also showed that a maximum resolution of at most 1.3 km is required to resolve the air/water interface issues, over 9 times finer than the coarse 12 km grid resolution used by the EPA.

Commenter (0394) states that the Long Island Sound Tropospheric Ozone Study (LISTOS) shows that the EPA's standard modeling does not accurately measure ozone concentrations in coastal areas or the contributions from upwind states to ozone concentrations in those areas. The commenter states that results of the 2017 Lake Michigan Ozone Study (LMOS) showed "'both the NAMCMAQ 12-km modeling and the higher resolution (4-km) WRF-Chem modeling' – both of which EPA used in modeling for the proposed rule – 'underestimate peak ozone concentrations and overestimate [nitrogen dioxide] concentrations during ozone episodes.'" According to the commenter, differences in ozone formation and transport in coastal areas are due in large part to the influence of sea breeze, or in the case of coastal areas around Lake Michigan, lake breeze. The commenter asserts that research on inland penetration of sea breeze has indicated that areas 30 to 40 kilometers (km) inland can be influenced by sea breeze and its effects, and that a more typical intrusion distance at midday is between 10 and 25 km inland. The commenter argues that specialized modeling techniques and considerations are needed to capture the unique meteorological conditions that lead to ozone formation in these areas, as well as whether and the extent to which upwind-state NO_X emissions contribute significantly to nonattainment or maintenance problems in these areas. The commenter also says that in VOC-limited areas, NO_X emissions reductions from upwind states linked to receptors in these coastal areas may not decrease ozone concentrations in the downwind areas, and may result in increased ozone concentrations in those areas. Commenter (0394) continues to state that the EPA appears to have addressed the 2017 LMOS in the proposed rule, but the commenter says that although the EPA asserts "the model closely replicates both the day-to-day variability and magnitude of the observed [maximum daily 8-hr average] ozone concentrations on most days" at receptors in coastal Connecticut, [Air Quality Modeling Proposed Rule TSD at A-11], data provided in Appendix B to the "Air Quality 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, indicates underprediction of ozone concentrations at the coastal Connecticut monitors relative to 2020 measured concentrations on a scale comparable to the Chicago area monitors. [Air Quality Modeling Proposed Rule TSD at B-3]. The commenter concludes that the EPA has likely overestimated the contribution of upwind-state NO_X emissions to ozone concentrations in urban coastal areas, and the ability of NO_X emissions reductions to reduce ozone concentrations in these areas. The commenter believes that if the EPA were to take unique coastal conditions into account, the EPA would identify fewer linkages.

Commenters (0395, 0528) argue the EPA must adjust its modeling approach to accommodate the complexities of the Chicago area to support the application of transport policies to benefit the area. According to the commenters, since the only receptors to which Texas is linked in the proposal are located in this Chicago lakeshore area, specifically the Chicago-Alsip, Chicago-South, Chicago- Northbrook, and Chicago-Evanston receptors in Illinois and the Kenosha-Water Tower, Racine, and Kenosha-Chiwaukee receptors in Wisconsin, the EPA must exclude Texas from the proposal. Sources in Texas will be overcontrolled if the EPA requires NO_X reductions that will have no effect on ozone formation at these receptors. Commenter (0528) continues, as discussed in the Sonoma Report, the EPA's modeling platform has dramatic bias and errors as a predictor of ozone in the Midwest. According to the comment, the model performance shows "significant inaccuracy" at all seven of the monitors linked to Texas and fails to characterize accurately the meteorology or air quality conditions in the Chicago area. In the commenter's view, model performance is so poor that the EPA removed a Wisconsin monitor from consideration at Step 2 of its 4-step interstate transport framework.

Commenters (0289, 0300, 0301, 0307, 0314, 0331, 0340, 0395, 0528, 0542) believe the model does not address the complex meteorological and photochemical regimes near the monitors and a review of the selection of days used in the calculations is needed for a proper evaluation.

Commenter (0301), the Minnesota Resource Recovery Association, has concerns with the modeling methodologies and results relied upon in the proposed regulation, specifically the modeling of the Lake Michigan shoreline region in Illinois and Wisconsin. The commenter asserts that the EPA, LADCO, MOG, and others have found it difficult to develop a model that accurately estimates ambient concentrations in this region. According to the commenter, the EPA's air quality models have struggled historically to accurately estimate ambient concentrations in this area due, in part, to the complex meteorology at the land/water interface. The commenter asserts that atmospheric conditions along the shoreline in this area create documented variability in ozone contribution between NO_X and VOCs that is not accurately modeled by the EPA in its determination of the states linked to maintenance/attainment with the monitors in Cook County, Illinois.

Commenters (0289, 0301) assert the EPA's air quality models have struggled historically to accurately estimate ambient concentrations in Lake Michigan's shoreline region in Illinois and Wisconsin. This is due, in part, to the complex meteorology at the land/water interface. The atmospheric conditions along the shoreline in this area create documented variability in ozone contribution between NO_X and VOCs that is not accurately modeled by the EPA in its determination of the states linked to maintenance/attainment with the monitors in Cook County, Illinois.

Commenter (0531) observes that the EPA characterizes the 2016v2 modeling platform as "the most current and technically appropriate information," despite the fact that it does not incorporate the model changes and improvements that LMOS 2017 data and studies indicates are necessary for the model to accurately characterize the chemistry and meteorology of ozone production, fate and transport behavior at the Lake Michigan land/water interface. Therefore, commenter argues, it cannot accurately characterize ozone concentrations at the monitors to which EPA tries to link Missouri emissions.

Commenter (0531) comments that the EPA's meteorology and air quality modeling are based on a 36 km and 12 km nested grid (EPA, 2022). Many of the monitors exceeding the 70 ppb standard are located on or near large bodies water. These monitors are heavily influenced by the land/sea or lake breeze. A 12 km grid for both the meteorological model and air quality model is not sufficient to resolve the land/sea breeze flows as well as air chemistry for these coastal monitoring sites as discussed in the LMOS 2017 study (Stanier & et al, 2021) and (Abdioskouei & et al, 2019). The LMOS 2017 study shows that for Lake Michigan coastal monitors the air quality model (WRF-CHEM) even at a 4 km resolution does not simulate the proper timing and structure of the land/lake breeze or the inland penetration of elevated ozone concentrations. (Stanier & et al, 2021) states, "To reproduce the timing and magnitude of the ozone time series at coastal monitors, ozone production over the lake must be correctly simulated; furthermore, details of the lake breeze must be accurate—–timing, horizontal extent, and vertical structure." Based on research findings from the LMOS 2017 study team (Abdioskouei & et al, 2019) a horizontal resolution of at most 1.3 km is required to reasonably resolve the complex meteorology of the air/water interface for the great lakes and coastal ocean areas. The LMOS 2017 Study participants reported that a 1.3 km grid spacing will assist in the resolution of the large ozone concentration gradients that often occur along the shoreline as well as the inland penetration of the lake breeze circulation.

Commenter writes that modeling performed by the EPA (EPA, 2022) and the LMOS 2017 study (Abdioskouei & et al, 2019) both showed a significant negative bias in predicted ozone concentrations along the Lake Michigan shoreline. Commenter explains that LMOS 2017 study researchers/scientists have experimented with increasing anthropogenic VOC emissions and decreasing anthropogenic NO_X emissions. These changes to the model emissions inventory inputs improved air quality model performance reducing the significant negative bias. Review of VOC speciation and spatio-temporal release patterns were also recommended by researchers. This evaluation by the LMOS 2017 participants indicates that the EPA model choices result in the model being unable to properly reproduce the chemistry of ozone production and the VOC/NO_X ratios at the monitors along the Lake Michigan shoreline. Commenter points out that these are the monitors that the EPA now determines are linked to Missouri emissions in this proposed FIP.

Commenter notes that similar conclusions about the inaccuracy of the modeling when compared to data collected around NYMA during the LISTOS 2018 study have been made in several papers by LISTOS researchers. In a 2020 paper for the Journal of Geophysical Research, Zhang, et al. found that large ozone gradients were measured in the range of 15 to 18 ppb/km on June 30 and July 1, 2018, on mobile transits of Long Island, NY. "These large O_3 spatial gradients were missed in the hourly O_3 forecasts made by Version 5.2 of the

Community Multiscale Air Quality (CMAQ) model (Figure S3; Appel et al., 2017), which was run at a relatively coarse 15-km resolution. Model simulations with a finer spatial resolution of about 1–2 km would be required to potentially capture such a large spatial gradient. In addition, consistently low to moderate NO 2 concentrations were measured on 30 June and 1 July at the times when there were large O_3 and Ox spatial gradients (Figures S4, 3, and 4). This suggests that the dramatic O_3 spatial variation on those days was influenced by factors other than NO-NO_2 -O3cycling kinetics." (Page 6 of paper) This suggests that this was influenced by the local sea breeze which CMAQ modeling couldn't resolve.

Commenters (0331, 0405) argue fine grid resolution modeling compromises the significant contribution findings that link Minnesota to two maintenance monitors in Illinois.

Modeling of Coastal Connecticut

Commenter (0340) points to three Connecticut monitors located directly on the Connecticut coastline in the Long Island Sound. The EPA is aware of issues with the land-water interface in the modeling raised by various Metropolitan Jurisdictional Organizations over the past few years. The continued use of this modeling, with the inclusion of these errors, is very concerning to Kentucky.

Commenter (0359) compared the EPA's 2016 v2 modeling platform results (12 x 12 km grid resolution) to the results of Alpine's Mid-Atlantic 4-km Region that found West Virginia was not previously linked to the receptors identified by the EPA. West Virginia is linked to receptors that the EPA acknowledges that its model over predicts the observed values during the height of the ozone season. Ignoring these known over predictions in the modeling will result in the overcontrol of sources located in West Virginia.

Modeling of Galveston Bay

Commenter (0760) states the Houston area has a complex land/water interface with many narrow inlets and Galveston Bay is quite shallow, so the bay warms more than the cooler Gulf of Mexico as the ozone season progresses. The modeling conducted by the EPA used a 12 km grid resolution which does not accurately portray the conditions within the Houston Galveston-Brazoria Area, when the EPA should have used a 1.3 km or 4 km resolution to model ozone levels at the part per billion range being addressed with the proposed rule. Commenter (0760) urges the EPA to review the Alpine Geophysics report prior to making any final determinations concerning Step 1 or Step 2 of the interstate transport analysis.

Modeling of Western Areas

Commenter (0314) states at the time of writing, the air monitor in Cheyenne read 35 ppb for 8-hr ozone, or half the national standard. If the wind were blowing south, one would presume that Wyoming's lower ozone concentrations would actually dilute the higher concentrations in the Colorado nonattainment area, making the air cleaner. However, the prevailing wind in

Cheyenne is generally from west to east, meaning it eventually travels into Nebraska or perhaps northeast Colorado, not Denver. Commenter (0314) adds the prevailing wind in Denver generally comes out of the southwest, meaning it will eventually cross through northeast Colorado, Kansas or Nebraska. During most of the year, the general wind directions do not lend themselves for emissions generated in Wyoming to travel to Denver. In fact, it seems more likely that emissions from sources along the Front Range have a better chance of coming into Wyoming.

The commenter (0509) states that the EPA' s use of a coarse 12-km grid resolution in its CAMx modeling, and its unrealistic assumptions that there would be no additional emissions controls in the Denver Metro / North Front Range (DMNFR) nonattainment area, overstates future year DV projections. The commenter asserts that this was confirmed by use of the 4-km grid resolution modeling for the DMNFR 2023 Severe/Moderate ozone State Plan that produced lower future year projected DVs, and resulted in Chatfield no longer being a nonattainment/maintenance receptor in 2026.

Commenters (0509, 0547, 0554) share the Denver ozone SIP used a 4-km grid to capture the meteorology and terrain more accurately in the very areas EPA claims are impacted by Utah and Wyoming. The Denver modeling shows that the monitors EPA claims are significantly impacted by Utah and Wyoming will achieve or make significant progress towards attainment by 2026, without and before the most stringent requirements for EGUs go into effect under the proposed rule. The problem of resolution is not solely a western state problem, but it is particularly pronounced in the mountainous western states where BHE businesses operate and where the EPA claims significant impacts are occurring.

Commenter (0547) states Colorado has varied elevations surrounding the Denver- Chatfield area, and some of these changes would be present in a 3 x 3 grid with grid cells measuring 144 sq. km in size. Commenter (0547) quotes a recent paper discussing the unique impact that meteorology and elevated terrain has on the formation of ozone in the Western United States. It noted that: In addition to bringing warmer temperatures, upper-level ridges in this region reduce westerlies at the surface and aloft and allow cyclic terrain-driven circulations to reduce transport away from sources. Upper-level ridges can also increase background concentrations within the ridge. O_3 and NO_2 concentrations build locally, and deeper vertical mixing in this region provides a potential mechanism for recapture of O_3 in layers aloft . . . O_3 precursors and 9 reservoir species in large- scale basin drainage flows can be brought back to source areas and nearby mountains by daytime, thermally driven upslope flows.

Commenter (0547) continues that the EPA recognized the existence of complex terrain, and that such terrain could make other grid models, at finer resolutions, more appropriate in Colorado’s SIP for the 2008 NAAQS. The 3 x 3 model indicated that by 2017 two receptors in the state, the Denver-Chatfield and Rocky Flats receptors, would be in non- attainment of the 75 ppb NAAQS. 83 Fed. Reg. at 14,812. Colorado presented the agency with a “weight of the evidence” analysis, in which it relied on an alternative 7 x 7 grid for modeling (for both the 3 x 3 and 7 x 7 grid modeling, the cells measured 4 km by 4 km each) that performed better than the 3 x 3 model, and the EPA itself suggested such performance difference may be: a result of challenges in accurately simulating meteorological data in Colorado's complex terrain combined with the use of a high resolution 4-km grid in the Colorado modeling platform. It is possible that small errors in wind speed or wind direction could result in model-simulated plumes being offset by more than 4 km from a monitoring site. The EPA's recognition that a finer resolution grid may be appropriate for Colorado is consistent with other studies that evaluated grid cell size. For example, Cohan et al. noted that 12-km grid cells at times lead to discrepancies in wind fields resulting in inconsistencies in the predicted location of ozone enhancements, especially for a power plant plume. Additionally, Balasubramanian et al., which evaluated impact of grid resolution on prediction of $PM_{2.5}$ and ammonia using CAMx, indicated that the –bias in ambient NH 3 concentration decreased by 33 percent at 4 km grid resolution. Commenter (0547) states the Relative Response Factors (RRF) values at both receptors decreased, and both receptors were modeled to be in attainment in 2017. Notably, the RRF value at Denver-Chatfield decreased by 0.0062 and the RRF at Rocky Flats North decreased by 0.0052.

Commenter (0547) concludes in order for the model to account for unique terrain considerations that are likely to impact the model results, the EPA must consider an alternative grid model that more appropriately fits receptors facing elevation issues, such as a 7 x 7 grid, with each grid cell measuring 4 km by 4 km.

Commenter (0520) argues that the EPA's analysis of Utah's upwind responsibility for downwind nonattainment under the proposed rule did not appropriately account for the impacts on downwind receptors of emissions from international and non-anthropogenic sources, emissions reductions in the downwind state (Colorado), and emissions reductions being achieved in Utah.

Commenters (0237, 0428, 0520, 0547) state across the West, high elevations, extreme variations in topography, vast landscapes, and variable weather patterns influence air quality. The West is also disproportionately affected by wildfires, high wind dust events, volcanic activity, and international transport of pollutants. Pollutant sources, methods of dispersion, and types of affected areas in the West are quite different from those in the eastern United States. The WESTAR region is complex in terms of air quality regulatory jurisdictions with interlinked responsibilities. In addition, a vast amount of the region are federal lands and federal agencies, including the EPA, have primary responsibility to manage and control air pollution sources on those lands and from sectors the CAA has reserved for federal control.

Commenter (0520) argues inclusion of Utah and other western states in the proposed rule is inappropriate and fails to consider specific geographic factors unique to western states.

Commenters (0436, 0554) draw attention to the unique challenges of reducing ozone in the western US. As a result of Utah's prominent location in the Intermountain West, Utah faces significant and geographically unique challenges in meeting ozone standards. These regionally specific challenges include substantially elevated background ozone levels, increasing instances and contributions of emissions from wildfire events, significant biogenic contributions, as well as influence from the international transport of pollutants. Commenter (0554) adds background levels of ozone in the west are higher, in some cases just below the current 2015 ozone NAAQS of 70 ppm.

Commenter (0303) says that previous interstate transport rules have not addressed California, and a different modeling approach is needed for FIP limit setting in California to be valid.

Given the large size of California and presence of mountain ranges affecting NO_X interstate transport, any FIP evaluation for California must break the states into regions and address topography. The commenter believes the EPA's modeling is invalid for California.

Specific Comments on Model Performance

Commenters (0323, 0331) state the time series of the daily observed and modeled maximum 8-hr average ozone concentrations at the Chicago-Alsip monitor observations and model predictions are both high, with some discrepancy in the magnitudes. However, on many days the model is predicting a high ozone event that does not occur or is entirely missing an observed high ozone period, an indicator of the model's poor performance in replicating observed ozone concentrations at this monitor on those days. Commenter (0331) continues that scatterplots of the daily maximum observed and model predicted daily maximum 8-hr concentrations at the Chicago-Alsip monitor demonstrates that the model tends to overestimate lower concentrations and underestimate higher concentrations with an R^2 value of 0.57; an indicator of poor performance in the high observed ozone range used for DV and significant contribution calculations.

Commenter (0505) argues at the seven monitors linked to Texas, the EPA's 2016v2 modeling is uniformly biased low, with five of the seven monitors below the Emery et. al. (2017) criteria range of less than $\pm$15 percent for normalized mean bias during May through September on days with observed eight-hr ozone averages of 60 ppb or more. The Kenosha, Wisconsin (550590019) monitor has a total normalized mean error a little over the 25 percent Emery et al. (2017) criteria range. This indicates model performance at these monitors is in the lower third of published performance reviews. In such instances, Emery notes that it is "critical to investigate the reasons for poor performance and to take measures to improve model performance before using the results for regulatory action."

Commenter (0289) also states the model is performing outside the acceptable range and significantly outside well-established model performance goals. Commenters (0289, 0528) express the EPA's 2016v2 modeling does not pass well-accepted performance benchmarks for acceptable ozone model performance in the Upper Midwest.

Commenter (0505) continues, in the Air Quality Modeling Proposed Rule TSD, the EPA acknowledges the significant low bias in the Midwest region but does not further evaluate model performance to determine if the cause of the low bias is due to meteorological or emissions inputs. Without establishing the cause of the low bias, it is inappropriate for the EPA to rely on the credibility of the modeling platform in establishing requirements in this proposed FIP. In instances when operational performance metrics indicate that there is poor performance, the EPA's 2018 modeling guidance recommends the use of diagnostic and dynamic model performance evaluation to gain insights into the reasons for poor performance. The model performance evaluation presented to establish the scientific credibility of the EPA's 2016v2 modeling platform and support this proposed action relies on broad, region-wide statistics that exceed the spatial recommendations of Emery and a graphical evaluation at a handful of sites (most of which show significant bias). The EPA should evaluate model performance to determine the cause of the low bias and use the recommended spatial extent of evaluation statistics.

Commenter (0531 Ameren) states the Chiwaukee Prairie site has the worst under prediction and performance worse than 97.5 percent of the monitors considered in EPA's analysis in terms of under prediction. The best site out of the four still ranks worse than 68.7 percent of the monitors evaluated. The three Wisconsin sites do not meet the EPA mentioned benchmarks for Normalized Mean Bias and with performances worse than 96.7 percent, 83.7 percent and 95.3 percent of the sites evaluated. The Illinois site just barely meets the benchmark for the Normalized Mean Bias, but its performance is worse than 66.8 percent of the sites evaluated. For the Normalized Mean Error, the Wisconsin Chiwaukee Prairie site does not meet the benchmark with its performance worse that 97.4 percent of the sites evaluated. The Wisconsin Chiwaukee Prairie and Payne and Dolan sites meet the lower two-thirds benchmark but their performance is worse than 83.7 percent and 95.9 percent of the sites evaluated. The Illinois Water Plant site again meets the lower two-thirds benchmark, but its performance is worse than 73.6 percent of the sites evaluated.

Commenter (0531 Ameren) states based on the EPA's 2016v2 analysis, Missouri significantly impacts 4 monitors that are either non-attaining or maintenance monitors for the 2015 ozone standard in 2023: three in Wisconsin and one in Illinois. These four monitors are all shoreline monitors effected by the lake breeze. In 2023 the Kenosha County Chiwaukee Prairie (#550590019) and the Racine County Payne and Dolan (#551010020) sites are modeled to exceed the 2015 ozone standard while Kenosha County Water Tower site (#550590025) and the Cook County Water Plant site (#170317002) are designated as maintenance monitors with max DVs exceeding 70.9 ppb. Based on the EPA's performance statistics (EPA, CAMx 2016v2 MDA8 O3 Model Performance Stats by Site, 2022) these monitors are among the worst performing (containing the most error) sites in the EPA's modeling analysis.

Commenter (0395) claims the proposal’s entire reliance on modeling to demonstrate the linkage and downwind monitor impacts as well the potential impact of control strategies is flawed. The EPA provided only 75 days for review of this complex package which was insufficient for a complete review of the modeling. However, in a report prepared by Sonoma Technology for, and submitted to this docket by, Baker Botts LLC on behalf of AECT and others (Sonoma Report), a detailed review of the EPA’s modeling analyses as conducted in this limited time and the findings show that the proposal is not based on adequate science. The EPA acknowledges some of the flaws in its modeling approach. To the extent the EPA performs additional modeling following the proposal, it is imperative, and required by law, that such modeling be subject to the entire rulemaking process including public review and comment. Therefore, the commenter urges the EPA to repropose the FIP once its modeling is complete and ready for public review. The commenter also states EPA model performance for Texas-linked monitors is unacceptable as demonstrated in the Sonoma Report, EPAs 2016v2 modeling platform performs so badly in the Great Lakes region that it cannot be relied upon to demonstrate that the seven Texas-linked sites, which are all located in the Chicago lakeshore area, will be nonattainment or maintenance or what the Texas impact on the area monitors might be. The Sonoma Report lays out that the EPA’s systematic bias and error associated with the Midwest region is over 19 percent, and even worse (up to 25 percent) when looking at the specific Texas-linked monitors. As noted in the Sonoma Report, other credible modeling by the EPA and Texas further calls into question whether these areas will in fact be nonattainment or maintenance areas as neither identifies the monitors as such. The basis for linking Texas sources to Chicago area ozone nonattainment is wholly unsupportable by the EPA 2016v2 model. The 4-step process for Texas should stop at this step.

Commenter (0547) goes further stating the EPA did note that based on its model performance evaluation, in western states such as Arizona, Colorado, New Mexico, and Utah, “there is notable spatial heterogeneity in mean bias. For example, in Denver there are some sites with mean bias within + 5 ppb while at relatively near-by monitors the model is low-biased by 5 to 10 ppb.” [see Air Quality Modeling Proposed Rule TSD, Appendix A at A-9]. In other words, across monitors in the Denver-area alone, its model both underpredicted and overpredicted ozone concentrations. While Basin Electric cannot infer what caused such spatial heterogeneity based on the data currently provided in the docket, The EPA must provide an assessment of what factors (such as unique terrain and meteorology) could cause the model to perform in such a manner in the Denver area.

Commenter (0554) adds the EPA rejected the very type of modeling it relies on to support the proposed rule when it denied the state of Utah’s recent request for an ozone exception. As the state of Utah has explained, the EPA relies on the 2016v2 model, which has a high negative bias, to support the proposed rule. The negative bias indicates that the EPA’s model is underpredicting either transport or local photochemical production (or some combination of both). The EPA cited a similar negative bias in Utah’s recent 179B(b) demonstration as one reason for rejecting Utah’s ozone demonstration. It is arbitrary and capricious for the EPA to reject Utah’s 179B(b) demonstration due to model underperformance while simultaneously using a model with similar underperformance limitations as justification to include Utah and other western states in the FIP.

Commenter (0436) states the combined deficiencies in the inventory and modeling platform used in the proposed rule resulted in a significant low bias in simulated ozone concentrations, with the EPA’s own assessment of regional scale modeling efforts identifying underestimations in US contributions to high ozone days. While commenter (0436) recognizes the significant challenges in modeling ozone concentrations especially at larger scales, they find it frustrating that the EPA used a similar level of modeling bias to be grounds for denying Utah’s recently submitted 179B(b) demonstration. It is contradictory to use modeling with nearly identical biases to deny a state-level action while simultaneously upholding an extensive federal action that has widespread national implications.

Commenter (0531 Ameren) continues, reviewing the normalize bias for the days used for development of the Relative Contribution Factor (RCF) none of the monitoring sites have a complete set of ten days that meet the EPA discussed benchmark of less than ±15 percent for the normalized bias. For the Kenosha County, Wisconsin Chiwaukee Prairie site only six of the ten days meet this benchmark with one additional day 20160804 barely meeting this benchmark. For the Racine County, Wisconsin Payne and Dolan only four of the ten days meet this benchmark. However, since the EPA only considered modeled days greater than or equal to 60 ppb only two days actually meet the benchmark. For the Kenosha County, Wisconsin Water Tower site only five of the ten days meet this benchmark. But using modeled levels 60 ppb or greater only one day does not meet the benchmark. For the Cook County, Illinois Water

Plant site only five days meet this benchmark. Furthermore, the commenter writes, for these four monitors, which are all shoreline monitors, the EPAs simulations are not performing well with more than 40 percent of the days considered for determination of the RCF not meeting the benchmark normalized bias of less than +15 percent. The EPA needs to evaluate why the modeling is performing so badly and redo the modeling. Due to this poor performance, it is unlikely a realistic and reliable RCF with this modeling is being achieved. The actual state impact on these monitoring sites is highly questionable. The commenter states, because the EPA is not modeling any nonattainment days at these monitors, it cannot determine that Missouri has any contribution to nonattainment based on source apportionment modeling of the modeled attainment days. EPA's 2023 modeling of the Cook-Water Plant monitor and the Kenosha Chiwaukee Prairie monitor results in two (2) exceedance days for each monitor.

Commenters (0323, 0331) continue the model deficiencies are also evident at the other maintenance monitor with which Minnesota is linked. Chicago-ComEd monitor (170310076) in Cook County, Illinois had five of the top six days selected for DV calculation are outside of the +15 percent normalized bias range, including the top four days used in this metric with a modeled concentration of 81.44 ppb and an observation of 56.43 ppb (normalized bias of 44 percent) – a gross discrepancy. Time series plots show high when observations and model predictions are both high with discrepancies in the magnitudes. However, on many days the model is predicting a high ozone event that does not occur, or is entirely missing an observed high ozone period, particularly in the spring. The model is systematically underestimating the linear regression ozone with an R^2 value of 0.58.

Commenters (0323, 0331) assure these performance issues are not unique to the Illinois monitors and are representative of other monitors located within complex land/water interfaces. Similar issues also exist at the Chiwaukee Prairie Stateline (550590019) monitor in Kenosha County, Wisconsin, a monitor which is also located in a very similar meteorologically complex area. At this monitor four of the top ten modeled days have normalized bias less than +15 percent. Commenter (0331) concludes days where modeled ozone was predicted at concentrations differing up to ± 24 ppb are being used to estimate future year ozone concentrations and to make determinations of nonattainment, maintenance, and significant contribution from upwind sources. Because of the demonstrated poor model performance, the EPA should remodel the Lake Michigan area as outlined its own air quality modeling guidance using a finer grid resolution to determine updated DVs and upwind state linkages, potentially unlinking Minnesota from any downwind monitor.

Commenter (0547) believes the EPA should run a model performance evaluation for the days selected for determining the RRF, to accurately assess the model as it relates to the RRF. A more narrowly tailored model can provide further insight into how well the model performs in predicting ozone changes in 2023 and 2026. To test the accuracy of its model, which it relied on at Step 1 during its grid analysis, the EPA ran its model for 2016, and then compared the modeled results to actual observed ozone concentrations in 2016. (see Air Quality Modeling Proposed Rule TSD, Appendix A.) the EPA created model performance statistics for the period of May through September and for individual months during this time period and for various regions. Based on this performance evaluation, the EPA concluded its predictions from the modeling platform “correspond closely to observed concentrations in terms of the magnitude, temporal fluctuations, and geographic differences" and that it has "confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions."

Commenters (0323, 0331) note Illinois monitors are proposed to be linked to Minnesota located along Lake Michigan. Studies indicate that air quality forecast models typically predict large summertime ozone abundances over water relative to land and that meteorology around Lake Michigan is distinctly unique compared to only "over land" or only "over water" grid cells in the region. Commenters (0323, 0331, 0405) point out photochemical grid model's normalized mean bias ozone goal is less than $\pm$5 percent and criteria is less than $\pm$15 percent.

Commenters (0331, 0531 Ameren) provide a table showing several days selected for RRF calculation with modeled ozone concentrations that fall outside of normally acceptable normalized bias criteria ($\pm$15 percent), either because of over (positive bias) or under (negative bias) predictions compared to observed concentrations on those days. In fact, at one particular monitor example, five of the top six selected days fall outside of the $\pm$15 percent bias metric, including the top modeled day. Of note, only three of the selected top ten modeled days had corresponding observations greater than 70 ppb.

Commenter (0547) notes modeled and monitored ozone at the Denver-Chatfield receptor fluctuated day-by-day, and on certain days the model actually over-predicted what was actually observed in 2016. At least one study, Emory et al., 2017, has recommended that the model performance evaluation should tailor its focus to the modeled days specifically relied upon to determine the RRF. Such an evaluation would be helpful in determining the site-specific model error and bias for the days used for estimating RRFs. Because the commenter cannot run the model itself, the EPA must undertake this analysis to better assess the accuracy of the RRF determinations.

Commenter (0436) states looking at the maximum daily 8-hr average (MDA8) model performance for the two Utah sites in the EPA's Air Quality Modeling Proposed Rule TSD (Figure A-17), it's apparent that the model did a relatively poor job replicating the top ten monitored MDA8. Relative Response Factors (RRFs) were calculated using the top ten modeled MDA8 concentrations, then the RRF was directly used in the calculation of future DVs for receptor sites and states' downwind contributions. Commenter (0436) believes if the model isn't capturing the highest ten MDA8 monitored days well, then it stands to reason that there are significant concerns about the model's ability to accurately quantify future DVs and a states' contribution to downwind nonattainment areas. A potential and significant result of these uncertainties is that sources identified for emissions reductions could be overcontrolled. If the model is not accurately predicting MDA8 values, it may be overestimating the amount of emissions reductions required to attain the standard, and thus the identified reductions may be beyond what is required.

Commenter (0760) adds RRFs are determined through comparing actual observations to model predictions. A review of the top 10 days (of ozone concentrations) at the Houston-Aldine monitor in Texas and comparisons of daily modeled maximum daily average 8-hr ozone concentrations (Base DV) and actual observations on the same date in 2016 showed that on most of the dates evaluated, concentrations that fall outside of normally acceptable normalized bias (NBias) boundaries (±15 percent), either because of over (positive bias) or under (negative bias) predictions compared to observed concentrations on those days. In fact, at the Houston-Aldine monitor, six of the ten selected days fall outside of the ±15 percent bias metric, including the top five modeled days, meaning that the modeling did not accurately reflect actual values on six of ten days. In short, "the performance of the model to replicate observed concentrations is outside of comparable acceptable ranges."

Response:

Commenters describe the "conceptual model" of local scale meteorological conditions that are typically associated with high ozone concentrations measured in areas around Lake Michigan and in western states where the EPA has identified nonattainment and/or maintenance-only receptors in 2023. Commenters claim that the EPA's projected DVs and contributions for receptors in these areas are flawed because the horizontal resolution of the EPA's modeling (*i.e.*, 12 km) is too coarse to properly resolve the emissions and meteorological conditions that lead to locally high ozone concentrations associated with the land/water interface in coastal areas and in complex terrain. In this regard, commenters argue that the EPA must use "fine scale modeling" (*i.e.*, 4 km resolution or 1 km resolution) to properly simulate ozone concentrations and the response to emissions changes, and thus provide credible projections of DVs and contributions for such areas. Commenters support their claim by pointing to model performance statistics from the EPA's modeling for 2016, which commenters say is biased low compared to the corresponding measured ozone concentrations at receptors in Coastal Connecticut, the Lake Michigan area, and in Colorado and Utah. Commenters then allege that the modeled response to emissions reductions (*i.e.*, RRFs) is correlated with base year model bias. That is, the commenters contend that the low-bias in the 2016 base year modeling implies that the model's response to the emissions reductions between 2016 and 2023 is also underpredicted. The commenters state that underpredicting model response results in DVs in 2023 that are too high and, therefore, the projected DVs *overstate* the magnitude and extent of the ozone problem in 2023. Commenters support these claims by noting that fine scale modeling performed for Colorado and the Lake Michigan area has less bias and error and produces lower projected DVs compared to the EPA's 12 km modeling. The commenters then allege that the error associated with underprediction in the base year is compounded in the calculation of future year contributions such that the contribution metric values calculated by the EPA overstate the magnitude of contributions from upwind states. Finally, noting that projected DVs and contributions are calculated based on the top 10 modeled concentrations days, commenters say that the EPA must discard from these calculations any days that do not meet certain model performance benchmarks.

The EPA agrees that fine-scale meteorological conditions associated with the land water interface coupled with the spatial distribution of ozone precursor emissions presents a challenge for modeling ozone formation and urban scale transport that affect monitoring sites in Coastal Connecticut and near the shoreline of Lake Michigan. The EPA also agrees that modeling for areas located in complex terrain, such as Denver and Salt Lake City present a similar challenge.

However, as described below, the EPA disagrees with commenter's assertion that finer scale modeling than 12 km is required to provide scientifically sound projections of ozone DVs and contributions to assess interstate ozone transport for this action.[33] In addition, the EPA disagrees that model performance benchmarks cited by commenters should be applied when identifying which days to use when calculating projected DVs and contributions. The EPA also disagrees with the notion that the magnitude of model response is correlated with base year model bias and error such that modeling that underpredicted measured concentrations also underpredicts model response.

Regarding comments on the use of fine scale modeling with respect to model performance, as stated in the EPA's modeling guidance, the use of fine scale modeling should be considered for the purpose of identifying local control strategies that will provide for attainment of the NAAQS in such areas. The guidance goes on to say, "If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary."

To gauge the adequacy of model performance for regulatory applications, the EPA's modeling guidance recommends comparing model performance statistics from the base year model run (*e.g.*, 2016) to model performance from other recent state-of-the-science model applications. Specifically, the EPA guidance recommends that "air agencies compare their evaluation results against similar modeling exercises to ensure that the model performance approximates the quality of other applications. Recent literature reviews (Simon et al, 2012; Emery et al., 2017)[34,35] summarize photochemical model performance for applications published in the peer-reviewed literature between 2006 and 2015. These reviews may serve as a resource for identifying typical model performance for state of the science modeling applications." The EPA has followed this guidance in evaluating the adequacy of model performance for the air quality modeling performed for the proposal and final transport actions.

The model performance criteria for MDA8 ozone concentrations recommended by Emery et al., are in the table below.

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[33] We note that 12 km grid modeling has been used for each of the EPA's prior interstate ozone transport rulemakings. *See, e.g.*, 81 FR at 74526. *See also Michigan v. EPA*, 213 F.3d 663, 682.

[34] Simon et al Simon, H., Baker, K. R., Phillips, S, (2012), Compilation and interpretation of photochemical model performance statistics published between 2006 and 2012, *Atmos Environ*, 61, 124-139.

[35] Emery, C., Liu, z., Russell, A.G., Odman, M.T., Yarwood, G., Kumar, N., (2017), Recommendations on Statistics and Benchmarks to Assess Photochemical Model Performance, Journal of the Air and Waste Management Association, 67:5, 582-598, doi:/10.1080/10962247.2016.1265027.

Table 3-1 Model Performance Criteria for MDA8 Ozone Concentrations

Metric	Criteria
Normalized Mean Bias (NMB)	≤ ± 15%
Normalized Mean Error (NME)	< 25%
Correlation Coefficient (r)	> 0.5

The EPA notes that the commenters' complaints were based on model performance for the 2016v2 modeling that the EPA used for the proposed disapprovals. As described in the "Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform" (Jan 2023), hereinafter referred to as the 2016v3 Emissions Modeling TSD and the Air Quality Modeling Final Rule TSD, for this final action the EPA is using the 2016v3 platform which includes numerous updates made in response to comments on the proposal. Model performance for ozone with the 2016v3 platform is substantially improved compared to model performance with 2016v2 (see the Air Quality Modeling Final Rule TSD for details on modeling performance for 2016v3).

In this RTC, we present a comparison of model performance and projected DVs at receptors in 2023 based on the EPA's 2016v3 modeling to the corresponding model performance and projected DVs from fine scale modeling covering the Lake Michigan area, Coastal Connecticut, and Denver.

The tables below provide model performance statistics based on CAMx modeling performed by LADCO,[36] the New York State Department of Conservation (NYS DEC)[37] and Ramboll for the DMNFR ozone implementation plan[38] along with performance statistics based on the

[36] Attainment Demonstration Modeling for the 2015 Ozone National Ambient Air Quality Standard Technical Support Document. Lake Michigan Air Directors Consortium. September 21, 2022.

[37] Yum, J., E. Zalewsky, Y. Tian, and K. Civerolo. Comparison of the CAMx performance of 2016-based modeling platforms at 12 km and 4 km resolution. 20th Annual CMAS Conference, November 01-05, 2021.

[38] Morris, R., T. Shah, M. Rodriguez, C-J Chien, and P. Vennam. Air Quality Technical Support Document (AQTSD) for the Denver Metro/North Front Range 2023 Severe/Moderate Ozone State Implementation Plan. Ramboll. August 2022.

EPA's 2016v3 modeling.[39] Normalized mean bias and normalized mean error statistics are used to compare model performance from the EPA's 12 km modeling to 4 km modeling from these other model applications.[40] Note that data from LADCO and Ramboll are based on "two-way nested" modeling in which a fine-scale grid is embedded within a coarse scale regional domain during the model simulation. With this configuration, there are no independent predictions at 12 km. The NYS DEC performed independent modeling at 4 km and at 12 km. Note also that each group calculated statistics for different time periods during the ozone season. The LADCO statistics are based on days with measured ozone concentrations above 60 ppb, whereas the Ramboll statistics are based on data for all days. Both sets of statistics (*i.e.*, with and without using a cut-off of 60 ppb) are available for the NYS DEC modeling. In all cases, the EPA 2016v3 model performance statistics were calculated for the same days that were used by LADCO, NYS DEC, and Ramboll for their applications. Finally, the differences in model performance and projected DVs between the EPA's 12 km modeling and the 4 km modeling from LADCO, NYS DEC, and Ramboll cannot be solely attributable to differences in grid resolution. Other factors, such as differences in 2016 and 2023 emissions used in each model application also have some effects on the results. In this respect, the NYS DEC modeling may provide the most consistent comparison between 4 km and 12 km modeling since both sets of modeling relied on similar emissions inputs.

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[39] For this analysis, the EPA leveraged existing, readily available, model performance statistics based on modeling by LADCO, the NYS DEC, and Ramboll for these receptors. In this regard, the data from these organizations may, in some cases, reflect preliminary modeling.

[40] The normalized mean bias is calculated by first subtracting the modeled values from the corresponding observed values paired in space and time. Then, the sum of these differences is divided by the sum of the observed concentrations. The normalized mean error is calculated in a similar manner except that the sum of the absolute value of the differences is divided by the sum of the observations. Both normalized mean bias and normalized mean error are expressed as a percent.

Table 3-2 Model Performance Statistics Based on LADCO's Modeling and EPA's 2016v3 Modeling

			Statistics for April – September (Percent)				
			Normalized Mean Bias ***Days Above 60 ppb***			**Normalized Mean Error** ***Days Above 60 ppb***	
Site ID	**State**	**Receptor**	**LADCO 4 km**	**EPA 12 km**		**LADCO 4 km**	**EPA 12 km**
170310001	IL	Alsip	-12.0	0.2		12.0	10.9
170314201	IL	Northbrook	-14.5	-3.9		14.5	10.5
170317002	IL	Evanston	-1.8	-0.9		13.8	9.6
550590019	WI	Chiwaukee	-11.1	-12.9		15.5	16.9
551010020	WI	Racine	-7.9	-10.9		14.1	15.2
551170006	WI	Sheboygan	-11.4	-11.6		11.4	13.2

Table 3-3 Model Performance Statistics Based on NYS DEC's Modeling and EPA's 2016v3 Modeling (Percent)

			Statistics for May – June (Percent)					
			Normalized Mean Bias *Days Above 60 ppb*			**Normalized Mean Error** *Days Above 60 ppb*		
Site ID	**State**	**Receptor**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**
90010017	CT	Greenwich	-12.8	-6.5	-7.3	14.7	12.7	8.3
90013007	CT	Stratford	-7.5	-8.9	-1.9	9.7	15.7	13.1
90019003	CT	Westport	-12.0	-10.0	-3.8	12.2	10.7	7.9
90099002	CT	Madison	-5.0	-7.1	-3.3	7.2	8.7	7.3

Table 3-4 Model Performance Statistics Based on NYS DEC's Modeling and EPA's 2016v3 Modeling (July-August)

			Statistics for July – August (Percent)					
			Normalized Mean Bias *Days Above 60 ppb*			**Normalized Mean Error** *Days Above 60 ppb*		
Site ID	**State**	**Receptor**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**
90010017	CT	Greenwich	-8.1	-3.3	-9.8	11.8	12.8	11.9
90013007	CT	Stratford	-9.7	-5.2	-0.3	15.6	12.2	12.4
90019003	CT	Westport	-13.0	-3.5	-0.1	17.1	13.2	12.7
90099002	CT	Madison	-7.2	-3.5	0.4	14.4	10.8	9.8

Table 3-5 Model Performance Statistics Based on NYS DEC's Modeling and EPA's 2016v3 Modeling (May-June)

			Statistics for May – June (Percent)					
			Normalized Mean Bias *All Days (no "ppb" cut-off)*			**Normalized Mean Error** *All Days (no "ppb" cut-off)*		
Site ID	**State**	**Receptor**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**	**NYS DEC 4 km**	**NYS DEC 12 km**	**EPA 12 km**
90010017	CT	Greenwich	-5.8	0.0	-0.5	12.4	13.6	12.7
90013007	CT	Stratford	-10.4	-9.2	-5.5	14.9	17.3	15.4
90019003	CT	Westport	-13.0	-5.8	-2.9	17.2	15.3	12.2
90099002	CT	Madison	-5.0	-4.2	-1.2	9.7	10.8	9.4

Table 3-6 Model Performance Statistics Based on Ramboll's Modeling and EPA's 2016v3 Modeling

			Statistics for June 1 - August 20 (Percent)				
			Normalized Mean Bias *All Days* *(no "ppb" cut-off)*			**Normalized Mean Error** *All Days* *(no "ppb" cut-off)*	
Site ID	**State**	**Name**	**Denver 4 km**	**EPA 12 km**		**Denver 4 km**	**EPA 12 km**
80350004	CO	Chatfield	0.1	3.8		9.2	10.1
80590006	CO	Rocky Flats	-0.4	2.1		8.8	9.4
80590011	CO	NREL	-2.0	1.8		8.6	10.7
80690011	CO	Ft Collins	-2.5	-3.0		7.8	9.2

Comparing model performance using 12 km versus 4 km modeling does not support the commenter's contention that model performance using fine scale, 4 km modeling results in model performance superior to what is obtained with 12 km modeling, even at receptors where the magnitude of ozone concentrations are highly affected by complex meteorological conditions. The data in the above tables show that normalized mean bias and normalized mean error statistics for both the 4 km and 12 km modeling are well within the range of the performance criteria recommended by Emery et al., and endorsed by the commenters at nearly all of these receptors. At some of the receptors in Coastal Connecticut and near the shoreline of Lake Michigan there is notably less bias in the EPA's 12 km modeling compared to 4 km modeling at the same receptor. At the NREL and Ft Collins receptors in Denver, the bias with 12 km modeling and 4 km modeling are similar. At the other two receptors in Denver, model bias is less at 4 km. The results of this analysis indicate that model bias and error in the EPA's 2016v3 12 km modeling is comparable, overall, to model performance using 4 km modeling.

Regarding comments on the use of fine scale modeling with respect to projected DVs, the EPA compared projected DVs for 2023 from the 4 km modeling performed by LADCO, the NYS DEC, and Ramboll to the EPA's projections for 2023 based on the 2016v3 modeling. These data are provided in the tables below. The data from LADCO and Ramboll are based on the application of the "3 x 3" approach for projecting DVs. The NYS DEC provided two sets of projected DVs; one set based on the "3 x 3" approach and a second set based on the "no water, except monitor grid cell" approach. To maintain consistency in this analysis, all the DVs in the tables below, including the EPA's 12 km modeling, are based on the "3 x 3" approach.

The comparison of DVs based on 12 km modeling to the corresponding DVs based on 4 km modeling indicates that projected average DVs from the EPA 12 km modeling are similar to those from the LADCO 4 km modeling and that both the LADCO and the EPA modeling identify the same set of monitors that have projected average DVs that exceed the NAAQS (*i.e.*, Chiwaukee and Sheboygan). A comparison of 12 km and 4 km DVs for receptors in Coastal Connecticut shows that 3 of the 4 Connecticut receptors have lower projected 2023 average DVs in the NYC DEC 12 km modeling compared to 4 km resolution. At these receptors the EPA 12 km 2023 average DVs are lower than both the 4 km and 12 km, based NYS DEC projected average DVs at all the Connecticut receptors. Finally, comparing the 4 km Ramboll modeling to the 12 km EPA modeling for receptors in Colorado indicates that the projected average DVs are very similar (within 1 ppb at 3 of the 4 receptors). The data shown here refute the claims by commenters that 12 km modeling will lead to systematically higher projected DVs compared to modeling simulations conducted at 4 km resolution and refute claims by commenters that there is a greater potential for "overcontrol" using 12 km modeling.

Table 3-7 Comparison of DVs for 2023 from LADCO's 4 km Modeling and EPA's 2016v3 Modeling

					LADCO 4 km	EPA 12 km	
Site ID	**State**	**Receptor**	**2021 DV**	**Preliminary 2022 DV**	**2023 Average DV**	**2023 Average DV**	**2023 Maximum DV**
170310001	IL	Alsip	71	72	67.5	68.2	71.9
170314201	IL	Northbrook	74	74	68.0	68.4	71.8
170317002	IL	Evanston	73	74	68.9	69.1	71.9
550590019	WI	Chiwaukee	74	75	71.6	72.0	73.0
551010020	WI	Racine	73	75	69.5	70.0	71.8
551170006	WI	Sheboygan	72	75	75.1	73.0	73.9

Table 3-8 Comparison of DVs for 2023 from NYS DEC's 4 km Modeling and EPA's 2016v3 Modeling

					NYS DEC 4 km	NYS DEC 12 km	EPA 12 km	
Site ID	**State**	**Receptor**	**2021 DV**	**Preliminary 2022 DV**	**2023 Average DV**	**2023 Average DV**	**2023 Average DV**	**2023 Maximum DV**
090010017	CT	Greenwich	79	77	75.2	73.9	72.0	72.6
090013007	CT	Stratford	81	81	77.1	76.0	73.3	74.2
090019003	CT	Westport	80	80	77.9	78.6	74.3	74.5
090099002	CT	Madison	82	79	73.7	72.0	71.2	73.3

Table 3-9 Comparison of DVs for 2023 from Ramboll's 4 km Modeling and EPA's 2016v3 Modeling

					Ramboll 4 km	EPA 12 km	
Site ID	**State**	**Receptor**	**2021 DV**	**Preliminary 2022 DV**[41]	**2023 Average DV**	**2023 Average DV**	**2023 Maximum DV**
80350004	CO	Chatfield	83	83	70.6	71.3	71.9
80590006	CO	Rocky Flats	81	83	70.3	72.8	73.5
80590011	CO	NREL	83	84	73.4	73.5	74.1
80690011	CO	Ft Collins	77	77	70.4	70.9	72.1

Regarding commenter's assertion that days with model performance outside the range of the performance criteria recommended by Emery, et al., should be removed from the data set used to calculate projected DVs and contributions, the EPA finds this approach to be inconsistent with the intended use of these criteria. These benchmarks are based on model performance aggregated across multiple monitors and many days. In this respect, it is expected that even in model applications that meet these benchmarks there would be some monitor/days with model bias and error that is outside the range of the benchmarks. It is therefore not appropriate to use these benchmarks to screen individual sites or days. Specifically, in Emery, et al., the authors "do not make recommendations for model performance benchmarks for individual monitors, recognizing that the importance of model performance at a specific site is application-specific." In addition, the authors state, "For ozone, we recommend calculating statistics over temporal scales of roughly 1 week (an episode), not to exceed 1 month."

Even though the EPA disagrees with commenter's assertion to "throw out" specific days at individual monitors for which model performance does not meet the criteria, out of an abundance of caution, the EPA performed a sensitivity analysis for selected receptors in which the projected 2023 DVs and contributions were recalculated after removing individual days that fell outside the Emery et al., criteria for normalized mean bias and/or normalized mean error. The EPA chose receptors in Coastal Connecticut, the Lake Michigan area, Dallas, and Denver for this analysis. The specific receptors included in this sensitivity analysis are Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado.

In this sensitivity analysis the EPA first examined the normalized bias and normalized error on each day to determine if model performance on the days used to project DVs and/or calculations fell outside the range of the criteria. Days with performance outside the range of

[41] It should be noted that both EPA and Ramboll modeling of 2023 project ozone levels substantially lower than recent measured ozone levels at the four Colorado receptors, which are all well above the 2015 ozone NAAQS for both certified 2021 DVs and preliminary 2022 DVs.

the criteria were removed from the calculation of project DVs and contributions. Next, using data for the remaining days, the EPA recalculated Relative Response Factors (RRFs) which were then applied to the 2016-centered base period average and maximum DV to re-project the 2023 DVs. The EPA then recalculated the Relative Contribution Factor for each upwind state to downwind receptor combination. The recalculated RCFs were then applied to the recalculated 2023 average DVs to calculate a new set of contribution metric values. The number of top 10 days at each receptor that were replaced with data from other days when recalculating projected DVs and contributions is given in the table below. For example, at the Stratford receptor, model performance on 4 of the top 10 days used to calculate RRFs was outside the range of the criteria. The data for these days were removed. Then the concentrations on days with performance within the range of the criteria were re-ranked to identify a new set of top 10 days. In the calculation of the average contribution metric, 5 of the original top 10 days at this receptor were replaced with data from other days.

Table 3-10

		Number of Original Top 10 Days Replaced in this Sensitivity Analysis	
Site ID	**Receptor**	**Recalculated DVs**	**Recalculated Contributions**
090013007	Stratford	4	5
170317002	Evanston	7	7
481210034	Denton	0	1
080590006	Rocky Flats	0	1

The table below provides the projected 2023 average and maximum DVs without the removal of any days (*i.e.*, Final Action DVs) and the recalculated 2023 DVs after removing days with model performance outside the range of the criteria (*i.e.*, days commenters claim have "poor performance"). The data in the table below indicate that there is less than a ppb difference between the two sets of DVs at Stratford and Evanston even though data on nearly half (Stratford) and more than half (Evanston) of the days used to project DVs were replaced with data from other days.

Table 3-11

			Projected 2023 DVs (ppb)			
			Final Action		Sensitivity	
Site ID	State	Receptor	Average DV	Maximum DV	Average DV	Maximum DV
090013007	CT	Stratford	72.9	73.8	72.1	73.0
170317002	IL	Evanston	68.5	71.3	69.2	72.0
481210034	TX	Denton Airport	69.8	71.6	69.8	71.6
080590006	CO	Rocky Flats	72.8	73.5	72.8	73.5

The following tables provide the contribution metric values for upwind states linked to the Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado receptors for this final action (*i.e.*, no days removed) and the sensitivity scenario (*i.e.*, days removed based on model performance). The highlighted contributions in these tables identify contributions that exceed the 1 percent of the NAAQS contribution threshold. The data indicate that removing days with “poor performance” does not appear to result in any systematic bias in the magnitude of contributions. That is, contributions increase for some states linked to a particular receptor while contributions from other upwind states linked to that same receptor decrease. For example, at Evanston the contribution from Wisconsin dropped by 50 percent, whereas the contribution from Arkansas nearly doubled to a level above the screening threshold. In addition, after removing days with “poor performance” the contribution from Louisiana increased to above the threshold. Although the contribution from Michigan to Stratford dropped to below the screening threshold after removing days with “poor performance,” the contribution from this state to Evanston more than doubled. Also, although Illinois contributes below the threshold to Stratford after removing days with “poor performance,” Illinois contributes well above the threshold to receptors in Wisconsin. The results of this sensitivity analysis indicate that the EPA’s findings in this final action are robust with respect to consideration of daily model performance at individual monitoring sites.

Table 3-12

Upwind State	Stratford, CT (090013007)	
	2023 Contribution (ppb)	
	Final Action	Sensitivity
IL	**0.72**	0.50
IN	**1.18**	**0.74**
KY	**0.80**	**0.84**
MD	**0.96**	**1.12**
MI	**1.38**	0.48
NJ	**7.22**	**7.94**
NY	**12.70**	**12.66**
OH	**2.04**	**1.79**
PA	**5.43**	**6.62**
VA	**1.15**	**1.25**
WV	**1.35**	**1.68**

Table 3-13

Upwind State	Evanston, IL (170317002)	
	2023 Contribution (ppb)	
	Final Action	Sensitivity
AR	0.46	**0.88**
IN	**6.40**	**7.01**
LA	0.14	**0.70**
MI	**1.11**	**2.50**
MO	**1.18**	**1.04**
OH	**0.96**	**1.49**
TX	**1.85**	**0.86**
WI	**2.32**	**1.17**

Table 3-14

Upwind State	Denton Airport, TX (481210034)	
	2023 Contribution (ppb)	
	Final Action	Sensitivity
AR	**0.92**	**0.89**
LA	**2.87**	**2.68**
MS	**0.91**	**0.85**
OK	**1.01**	**1.09**

Table 3-15

Upwind State	Rocky Flats, CO (080590006)	
	2023 Contribution (ppb)	
	Final Action	Sensitivity
CA	**1.44**	**1.15**
UT	**1.17**	**1.12**

The EPA disagrees with comments suggesting that the EPA's modeling is unreliable due to changes in receptors between modeling runs. When multiple rounds of modeling, each more up-to-date than the last, continue to confirm certain upwind states are linked, it actually reinforces the EPA's conclusion that the upwind state is contributing to receptors at Step 2 of the 4-step interstate transport framework. A change in modeling output from the 2011-based modeling to the 2016-based modeling results in part from the shift to a more recent meteorological year and other updates. It is reasonable and acceptable for the Agency to update its modeling platform periodically and to do so before taking final rulemaking action. We adopt the same position here as articulated in our response to comments on this topic in the 2015 ozone NAAQS interstate transport SIP disapproval action's response to comment document at pp. 199-205. This document is available in Docket ID EPA-HQ-OAR-2021-0663.

3.2.3 Other Modeling Platform Topics

Comment:

Commenter (0517) says Oklahoma relied on the EPA's modeling to identify the initial six impacted receptors in Step 1 of the 4-step interstate transport framework but the EPA used a completely different modeling for its decision to disapprove of Oklahoma's SIP and identified a new receptor supposedly impacted by Oklahoma. The commenter says there should be some basic good faith measure of predictability for the end goal and the method to get there.

Response:

The EPA's assessment of Oklahoma's good neighbor SIP submission for the 2015 ozone NAAQS (as well as several other states' SIP submissions) is in a separate action. 88 FR 9336 (February 13, 2023). The EPA's 2011-based modeling released with the March 2018 memorandum was not used to support the proposed or final FIPs. The commenter did not raise any concern with the EPA's 2016v2 modeling with reasonable specificity.

At proposal, the EPA relied on CAMx Version 7.10 and the 2016v2 emissions platform to make updated determinations regarding which receptors would likely exist in 2023 and 2026 and which states are projected to contribute above the contribution threshold to those receptors. As explained in the preamble of the proposal and further detailed in the AQM TSD and the 2016v2 Emissions Inventory TSD, the 2016v2 modeling built off previous modeling iterations used to support the EPA's action on interstate transport obligations. The EPA continuously refines its modeling to ensure the results are as indicative as possible of air quality in future years. This includes adjusting our modeling platform and updating our emissions inventories to reflect current information.

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 in November of 2020, 85 FR 68964). 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. The CAMx modeling software that the EPA used has likewise been publicly available for over a year. 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. Please refer to Section IV.B of the preamble for an explanation of updates to the 2016v2 modeling resulting in the 2016v3 modeling. By using the updated modeling results, the EPA is using the most current and technically appropriate information for this rulemaking.

Both changes in emissions inputs and meteorology can impact modeling results. The EPA's separate modeling runs in the 2011-based modeling and the 2016v2 and 2016v3 modeling all show (1) that there were receptors that would struggle to attain or maintain the NAAQS in the future, and (2) that Oklahoma was linked to some set of these receptors, even if the receptors and linkages differed from one model run to the next. This common result indicates that Oklahoma's emissions are substantial enough for the EPA's contribution assessment to generate linkages at Steps 1 and 2 to some set of downwind receptors, under varying assumptions and meteorological conditions, even if the precise set of linkages changed between modeling runs. In sum, the continued identification of Oklahoma linkages with updated modeling reinforces the conclusion that the state is significantly contributing to nonattainment or interfering with maintenance in another state.

Comment:

Commenters (0505) assert that the EPA's analysis does not account for the varied source types and distances in large states such as Texas, which could result in insufficient justification for the emissions controls required in the proposal. The commenters state that elevated sources, such as tall stacks from EGUs, generally lead to greater impacts to downwind areas than ground-level sources such as mobile emissions that have greater local impacts. The commenter argues that the EPA is assuming that reductions to NO_X emissions from all source types will lead to equivalent downwind impacts to air quality and that such an assumption may bias the estimation of impacts for states with many different source types, such as Texas, and the EPA must ensure it has correctly accounted for the elevation of sources.

Response:

The EPA uses the 3-dimentional air quality CAMx to quantify interstate contributions. In this modeling we calculate the emissions release height of elevated point sources considering plume rise based on stack height and diameter, effluent exit velocity or flow rate, and temperature coupled with in situ meteorological conditions. In this regard the modeling reflects any differences in downwind contribution from elevated versus low level ozone precursor emissions sources.

3.3 Emissions Inventory Data Used in Modeling

3.3.1 EGUs

Comment:

Commenter (0764) states that the EPA failed to include on-the-books NOx reductions at Arkansas EGUs, resulting in overcontrol. For example, the commenter remarks that the EPA failed to account for enforceable closures of multiple EGUs in Arkansas, which will eliminate more NOx emissions from the state than all of the proposed reductions. According to the commenter, the proposed rule's limits for non-EGUs on top of these closures will result in overcontrol. The commenter identified the No. 1 Power Boiler at Domtar's Ashdown, AR facility and the 10A Boiler and 8R Recovery Furnace at Georgia-Pacific's Crossett, AR facility as already retired. The commenter identified that Georgia-Pacific's 9A Boiler is retiring in summer 2022.

Commenter (0554) notes it is not apparent that the EPA's assessment of Utah's impact reflects consideration of emissions reductions that are planned by PacifiCorp in upcoming years, including NOx reductions that will be required at both Hunter and Huntington under regional haze SIPs, or other emissions reductions and contributing factors that were raised by Utah in its own analysis in support of its good neighbor SIP for the 2015 ozone standard. The commenter provided the same reason of not fully considering reductions in support of the exclusion of Wyoming in the rule.

Commenter (0323) maintains that the EPA's delayed announcement of its intent to make findings that certain states have failed to submit regional haze implementation plans for the second planning period, delayed the implementations of the Regional Haze program and potential emissions reductions.

Commenters (0323, 0331, 0424) maintain that the EPA's modeling and emissions inventories fail to provide a wholistic assessment of emissions control requirements and must include on-the-books control programs and related permitted emissions limits on ozone precursors that significantly impact air quality DVs in 2023 and beyond. The commenters, in general, maintain that downwind states and regulated entities are on an ever-changing path to manage the complex implementation of emissions reductions programs to address local and regional impacts on ambient air quality. The commenters agree that the EPA's modeling of applicable emissions control programs to assess attainment strategies supports the iterative nature of these programs; however, they stress that private sector and government investments in emissions reduction strategies are considerable. Commenter (0323) briefly describes a few examples (along with commenters 0331 and 0424 whom also included descriptions for one or more of the control programs listed) to illustrate the types of emissions control regulations/programs that the EPA should include in the emissions inventory that was modeled to support the transport proposal –

(1) The Illinois EPA is addressing gas-fired generators through several new, pending permits (Title V, Federally Enforceable State Operating Permits);

(2) The Illinois Energy Law, aka Climate and Equitable Jobs Act should be considered as an applicable control program, as it significantly limits the emissions of NO_X from all existing gas fired EGUs in Illinois;

(3) New York State Department of Environmental Conservation (NYDEC) has developed recent controls for simple cycle and regenerative combustion turbines (SCCT), or "peaking units",

(4) NYDEC also recently imposed NO_X controls on distributed generation units, which as with peaking units, has been structured to delay implementation of controls beyond the applicable attainment date as part of the attainment plan proposed for approval by the EPA [87 Fed. Reg. 4,530 (Jan. 28, 2022)]; and

(5) Wisconsin Department of Natural Resources (DNR), Air Management Program has initiated a number of permitting actions in response to designation of Kenosha County as serious nonattainment (implemented as recently as the last 24 months), imposing new NO_X and VOC emissions reductions. The commenters inform that some regulated facilities are seeking relief from additional non-attainment reductions in advance of EPA approval of a partial redesignation of Kenosha County as attainment for the 2008 ozone standard.

Additionally, the commenters highlight examples of state and federal air program elements that warrant review by the EPA for impact on the efficacy of attainment strategies, including the Wisconsin DNR regulations included in Chapter NR 436 titled, "Emission Prohibition, Exceptions, Delayed Compliance Orders and Variances." NR 436.03(2)(c). The commenter contends that consideration of these upwind and downwind state control programs is critical not only to assure the correct modeling results in the future analytical year, but also to allow an assessment of the alignment of the emissions reduction burdens of the upwind and downwind states.

Response:

In response to commenters' requesting the inclusion of the retirements of EGUs and approved regional haze requirements, the EPA has incorporated information from these comments and additional feedback from power sector stakeholders and others into the power sector emissions projections that are used in the final photochemical grid modeling (2016v3) where the EPA has reviewed and determined that information to be sufficiently reliable and appropriate for use. The EPA does not include in the baseline modeling projections at Steps 1 and 2 emissions changes from EGUs or other emissions sources that are not sufficiently certain to occur, for example, if such projected emissions changes are only anticipated under proposed but not finalized state or federal rules, or where the potential retirement or conversion of units is not sufficiently committed to be considered reliable. To review modifications that were or were not incorporated, please view the "Unit Specific Comment Log" included in the docket for this rulemaking.

In response to the commenter's claim that the EPA should incorporate emissions reductions from Illinois's pending permitting actions, it is the EPA's standard practice to only consider emissions reductions from rulemakings or permitting actions that have been finalized. With regards to "The Illinois Energy Law, or the Climate and Equitable Jobs Act", we have accounted for this law in the 2016v3 modeling and it has been added to IPM as described in the "Updates in the Power Sector Modeling Baseline Projections for 2015 Ozone NAAQS Actions."

In regard to commenter's insinuation that the NYDEC's recent rule requiring controls on certain SCCT units are inappropriately misaligned with the attainment schedule of the NYMA nonattainment area, this is not a relevant comment on the modeling emissions inventory. However, the EPA notes that the prior approval of the SCCT controls (approved by the EPA as a SIP strengthening measure) is not reopened for consideration by the Agency in this action. The EPA previously responded to the Midwest Ozone Group's (MOG's) comments on the SCCT controls in the notice for that separate final action. *See* 86 FR 43956, 43957-43958 (August 11, 2021). We further respond to MOG's comments on this topic in of this Response to Comment document and in Section IV.A of the preamble.

In response to commenter's claim that the EPA should incorporate emissions reductions from Wisconsin's pending permitting actions to address the Kenosha County's nonattainment status for the 2008 ozone standard, it is the EPA's standard practice to only consider emissions reductions that have been finalized.

With respect to state and federal regulations that impact the efficacy of attainment strategies, the commenter provided an example of an exemption program in Wisconsin that could potentially be used under emergency or sporadic events. The commenter included text from the regulation but did not provide any examples or data on how it may have been used and its impact on ozone precursor emissions. In addition, the regulation allows for state officials to approve or deny the request. The EPA cannot determine how state officials will react or address this during these emergency or sporadic events. The EPA has incorporated any applicable EGU control programs developed by the states, including for the state of Wisconsin, into its projections and modeling. A listing and discussion of these regulations and control programs can be found in chapter three of the EPA's documentation for IPM and the "Updated Summer 2021 Reference Case Incremental Documentation for the 2015 Ozone NAAQS Actions." These can be viewed at 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; and https://www.epa.gov/power-sector-modeling/supporting-documentation-2015-ozone-naaqs-actions

3.3.1.1 Claims of EGU Data Input Error

Comments:

Commenter (0394) express concerns that the assumptions used by the EPA in developing the proposed FIP and, more specifically, state emissions budgets, are heavily flawed (inaccurate and unsupported), and as a result, the commenter warns of reliability concerns. The commenter provides a brief description of the 9 states – Arkansas, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Texas, West Virginia and Wyoming – evaluated in the Technical Report; noting these states represent different geographic regions of the 25 states included in the EGU portion of the proposed rule, as well as different RTOs and utility structures. According to the commenter the EPA failed to accurately assign NO_X emissions rates to SCR and non-SCR units sharing a common stack, modeling included inaccurate assumptions regarding natural gas conversions at EGUs in the nine states, incorrect assumptions were made regarding unit retirements in several states, and incorrect technology inventory data were included for units in several states; indicating flaws in EPA's unit-level assumptions.

The commenter also recommends that the Agency adjust the modeled emissions rate for combustion controls to reflect variability based on fuel and boiler type. The commenter maintains that before issuing a final rule, the EPA must recalculate the budgets for all 25 states to correct any errors in the baseline modeling for poor unit-level assumptions and eliminate poor assumptions relating to timing for installation of controls and make this modeling and the resulting adjustments available for public comment. The commenter clarifies that within the nine states examined (in the technical report), IPM projected retirement of 32 coal units, representing 9.7 GW of capacity, that have not announced plans to retire within that timeframe, including nine units totaling 6.6 GW that are equipped with SCR. The commenter adds that IPM also projected that 42 coal units, representing 14.9 GW of capacity, would be idled in 2023, seventeen of which (totaling 8.5 GW of capacity) are equipped with SCR. The commenter concludes that IPM incorrectly projected that over 28 percent of operable coal capacity will be idled during the 2023 ozone season, and these errors are compounded by incorrect assumptions regarding the feasibility of generation shifting.

Commenter (0309) notes the EPA requests comment, with supporting data, on whether the estimated historical ozone season heat input and emissions data identified for the units in Table VII.B.3-1 are representative for the three DCR boilers (DCPP2, DCPP3, and DCPP4) and the two DCR combined cycle units (MECCUl and MECCU2). With the exception of DCPP4 (Boiler #4), the ozone season heat input data in Table VII.B.3-1 is not representative of historical heat input values. For DCPP3 (Boiler #3) EPA's value is about twice historical levels. The commenter states for the remaining three units EPA's values are much lower than actual historical heat inputs. Historical ozone season NO_X emissions rates for DCPP4 (Boiler #4), MECCUl (Combined Cycle Unit 1), and MECCU2 (Combined Cycle Unit 2) are relatively consistent with the EPA values in Table VII.B.3-1, therefore, the EPA values are representative of DCR ozone season NO_X emissions rates for these three emissions units. Table VII.B.3-1 ozone season NO_X emissions rates for DCPP2 (Boiler #2) and DCPP3 (Boiler #3) are not representative of historical ozone season rates. The historical rates for DCPP3 are about 2.5 times the value EPA provides in Table VII.B.3-1.

Commenter (0309) states EPA requests comment, with supporting data, on whether the estimated historical ozone season heat input and emissions data identified for the units in Table VII.B.3-1 are representative for the three DCR boilers (DCPP2, DCPP3, and DCPP4) and the two DCR combined cycle units (MECCUl and MECCU2). Commenter (0309) states:

- With the exception of DCPP4 (Boiler #4), the ozone season heat input data in Table VII.B.3-1 is not representative of historical heat input values. For DCPP3 (Boiler #3) EPA's value is about twice historical levels. For the remaining three units EPA's values are much lower than actual historical heat inputs.
- Historical ozone season NO_X emissions rates for DCPP4 (Boiler #4), MECCUl (Combined Cycle Unit 1), and MECCU2 (Combined Cycle Unit 2) are relatively consistent with the EPA values in Table VII.B.3-1, therefore, the EPA values are representative of DCR ozone season NO_X emissions rates for these three emissions units.
- Table VII.B.3-1 ozone season NO_X emissions rates for DCPP2 (Boiler #2) and DCPP3 (Boiler #3) are not representative of historical ozone season rates. The historical rates for DCPP3 are about 2.5 times the value EPA provides in Table VII.B.3-1.

Commenter (0372) voices the base case identifies incorrect unit capacities. The budgets assign net capacities to some units and gross generation to others. The EPA relies on the unit capacities to compare against the Rule’s thresholds, such as the threshold for oil/gas SCR retrofits. The unit capacities should follow an accurate and consistent approach. According to commenter (0372), the base case capacity factors cannot be reproduced and may be in error. The commenter suspects the flawed and inconsistent unit capacities are likely the cause of the inability to reproduce the unit capacity factors that the EPA has devised. Commenter (0372) was unable to confirm the 2021 unit capacity factors are accurate.

Commenter (0381) requests reevaluation of SPS Unit 1 in terms of its not having a functioning non-catalytic reduction (SNCR) control system, no wet flue gas desulfurization (WFGD) control system, higher capacity factors than assumed by the EPA, and a much higher SCR Retrofit Costs than estimated by the EPA.

Commenter (0500) submits a spreadsheet [SoCo_NEEDS_v6.21_Review_20220608] in pdf and xlsx format, which provides the necessary corrections and updates resulting from their review of the National Electric Energy Data System (NEEDS) v6.21 database. The spreadsheet follows the basic format of the [needs-v6_01-24-2022] file posted to the Power Sector Modeling Platform. The commenter includes the following corrections and updates:

Operational Status, ACI Online Year, Mercury Controls, Mercury Controls Efficiency, NO_X Rates, Modeled Fuels, NO_X Comb Control, NO_X Post-Comb Control, Owner Name, Plant Name, PM Control, SCR Online Year, and Scrubber Efficiency.

Commenter (0500) notes the EPA's spreadsheet [unit-level-allocations-and-underlying-data-for-the-proposed- rule] included in the TSDs is missing Mississippi Power Company's ("MPC") Plant Victor J Daniel Unit 2 ("Plant Daniel Unit 2") [UNIQUE ID: 6073_B_2]. Plant Daniel Unit 2 operated during all five control periods between 2017 and 2021 and is currently allocated allowances as a Group 2 unit. Plant Daniel Unit 2 does not have a retirement date before the 2023 control period. Therefore, the EPA clearly should reevaluate the budget and the unit allocations for the state of Mississippi and assign Plant Daniel Unit 2 allowances commensurate with its historical operations.

Commenter (0541) states PowerSouth's new natural gas-fired combined cycle Lowman Energy Center, currently under construction, is projected to commence operation in 2023. Projected ozone season heat inputs for 2023 and 2024 are 13,445,287 and 13,433,080 MMBtu, respectively. In 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, Ozone Transport Policy Analysis Proposed Rule TSD" (Feb. 2022), hereinafter referred to as Ozone Transport Policy Analysis Proposed Rule TSD, Appendix A spreadsheet, Lowman Energy Center has a combined ozone season heat input of 9,578,467 MMBtu. Given the emissions rate of 0.010 lb/MMBtu, the EPA has projected ozone season NO_X emissions of 53 tons; however, current projections indicate that Lowman Energy Center will require 74 tons to be in compliance.

Commenter (0552) states the total for Eagle US 2 should be 970 tpy which is the total of the Powerhouse C units (C1, C2, C4, and C5 = 944 tpy) plus the PPG C Caustic Unit (26 tpy). The total for RS Cogen should be 562 tpy which is the total from RS-5 and 6, as RS-4 is non-emitting. The commenter states EPA has erroneously assigned emissions that actually come from RS-5 and RS-6 to RS-4.

Commenter (0552) states there are three powerhouses at the Eagle US 2 LLC complex in Lake Charles which have units addressed by the EPA as EGUs in its NEEDs v6 inventories – Powerhouse A, Powerhouse B (also known as the Riverside Powerhouse), and Powerhouse C. The EPA has duplicative and incorrect information concerning several of the units at these powerhouses in the inventories that were used in this proposed rule. The commenter stresses this is not correct and has not been since January 2013. All of these "PPG" labeled units are owned and operated by Eagle US 2 LLC. The three units described as "RS Cogen" are described in NEEDs v6 as being 50 percent owned by Energy Power Corporation. This is incorrect, as they have always been owned by RS Cogen LLC. They are operated by Eagle US 2 LLC. RS Cogen LLC is a joint venture of Entergy Power and Eagle US 2 LLC. The commenter notes the following:

- Powerhouse A unit A7 under ORIS Code 50487 is a steam turbine with no combustion
- Powerhouse B (Riverside Powerhouse) – ORIS Code 55117

- Units RS-5 and RS-6 are combined cycle natural gas turbines with heat recovery steam generators (HRSGs) (duct burners). These two units are subject to CSPAR and are equipped with DLNB and SCR.
- Unit RS-4 is a non-emitting steam turbine with no combustion; it does not have LNBs or SCR as it is non-emitting. EPA appears to have erroneously assigned emissions to this unit.
- The two units described as PPG Riverside under ORIS Code 50488 as GEN2 and GEN 3 were non-emitting units and have not operated since 2005.

- Powerhouse C - ORIS Code 50489
  - Units C1/C2/C4/C5 are all gas turbines. All are cogeneration units that sell less than1/3 PEOC and less than 219,000MW annually to the grid and are exempt from CSAPR.
  - Note that this powerhouse also has a unit C3, not identified in NEEDs v6 which is a steam turbine with no combustion and no emissions.
- Plant C Caustic ORIS code 50490- identified as unit "TE". This is a turbo generator, a type of steam generator, with no combustion and no emissions. This unit utilizes process steam after use in plant C to generate electricity.

Commenter (0552) continues, the spreadsheet EGU Compare 2023 Emissions (2023v2) (002)(003) shows the following NO_X emissions projected for 2023 for units at the Eagle US 2 LLC facility. (https://gaftp.epa/gov/Air/emismod/20166/v2/2023emissions):

- Eagle US 2 LLC - 1397 tons (comprised of 944 from C powerhouse and 454 from RS5- and RS-6)
- PPG C Caustic - 26 tons
- PPG Powerhouse A - 0 tons
- PPG Powerhouse C - 0 tons
- PPG Riverside - 0 tons
- RS Cogen - 108 tons (comprised only from RS-4)

Commenter (0554) states the 2021 ozone season NO_X emissions and corresponding heat input from Fort Churchill Unit 2 in 2021, as listed in the Clean Air Markets Division – Air Markets Program Data (AMPD database was 111.045 tons. This value should be added to the Nevada baseline of 2,346 tons to set a revised baseline of 2,457 tons (*i.e.*, 2,346 plus 111). Commenter (0554) provides Fort Churchill Unit 2 baseline heat input equal to the average of the 3 highest years from 2017- 2021, for purposes of unit allowance allocations. Adding this average value to the current 2023 proposed baseline of 108,449,874 MMBtu equates to 110,323,731 MMBtu.

Commenter (0554) mentions, according to Table VII.B.3-1 of the proposed rule, Nevada will likely see the addition of eight affected units, including Clark Generation Station Units 4-8, Nevada Solar One, and Saguaro Units CTG1 and CTG2. Using EPA's ozone season heat input and NO_X emissions rates, the NO_X emissions for these units are equal to or greater than 140 tons. The commenter understands the eight units were not initially included by the EPA because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical. Since these units do not report to the Acid Rain Program, they appear to have been overlooked. However, EPA also relies on EIA data, where correctly reported information indicates the eight identified units meet the Group 3 trading program applicability requirements. Commenter (0554) adds the proposed Nevada ozone season 2024 NO_X budget is 2,230 (without the corrections identified). This proposed budget reflects an increase of 87 allowances and incorrectly represents the 2021 ozone season NO_X emissions of 141 tons using EPA's Table VII.B.3-1 heat input values and NO_X emissions rates. Once these eight units are included in the budget, the Nevada ozone season 2024 NO_X budget will be an additional 54 allowances short, on top of the shortage identified. This again will cause an immediate decrease in operation and/or purchase of NO_X allowances to cover shortages. The commenter requests the Nevada budget allocation be revised and unit distribution recalculated to account for EPA's mathematical errors.

Commenter (0554) states Nevada Energy's Tracy Generating Station includes Unit 6, a 107 MW natural gas-fired combined cycle turbine. The commenter references "Unit-Level-Allocations-and-Underlying-Data-For-The-Proposed-Rule" Excel workbook that lists Tracy Unit 6 going from 136 tons of emissions in 2021 – assuming a 167- ton 5-year maximum and a 167-ton 2024/2025 allowance allocation – to a 66-ton allowance allocation for the 2026 control period (as shown in the "Underlying Data for FIP" tab). The proposed 2026 Tracy Unit 6 allocation of 66 tons equates to an emissions rate of 0.07 lb/mmBtu. However, this emissions rate does not agree with the table referenced in section 97.1010 (a)(iii)(A) that lists an emissions rate of 0.151 lb/mmBtu. Commenter (0554) requests the Tracy Unit 6 allowances for 2026 be recalculated using the 2021 heat input and the 0.151 lb/mmBtu emissions rate, thus yielding 136 tons.

Commenter (0554) states some 2023 allocations appear to result from the assumption that LNB/OFA have not been installed for Hunter Unit 3 and Naughton Unit 1. Both units currently utilize LNB/OFA.

Commenter (0554) states Hunter Unit 3's historic NO_X baseline emissions indicate a value of 2,178 tons and the 2023 allocation indicates 1,777 tons. This reduction appears to result from a projected 2023 NO_X rate of 0.26 lb/mmBtu upon the installation of BART (*i.e.*, LNB/OFA) or other EPA limits. PacifiCorp installed LNB/OFA on Hunter Unit 3 in 2008 and has a permitted NO_X limit of 0.34 lb/mmBtu. Hunter Units 1 and 2 also have LNB/OFA installed and are of similar heat input capacity to Unit 3. However, Units 1 and 2 are tangentially fired, while Hunter Unit 3 is wall-fired. Hunter Units 1 and 2 are permitted at a lower 0.26 lb/mmBtu NO_X rate. The different boiler configurations result in the different NO_X rates, but all three Hunter units are equipped with LNB/OFA. Commenter (0554) requests that the EPA reevaluate the Utah budget to account for Hunter Unit 3's NO_X rate and adjust the 2023 and 2024 ozone season allocations to reflect these controls.

Commenter (0554) states Naughton Unit 1's historic NO_X baseline emissions indicate a value of 588 tons, and yet the 2023 allocation indicates only 312 tons. This reduction appears to result from an assumed requirement for this unit to install LNB/OFA. However, Naughton Unit 1 has already installed LNB/OFA. Commenter (0554) requests that the EPA reevaluate the

Wyoming budget to remove the LNB/OFA reduction for Naughton Unit 1's 2023 and 2024 ozone season allocations to reflect this information. Commenter (0554) continues, the EPA lists Dave Johnston Unit 1 with a capacity greater than 100 MW. However, the most recent data indicates the correct capacity during ozone season is 93 MW (EPA used 2018 summer net capacity values to establish unit capacities, as indicated in needs-v6_01-24-2022-2 and EPA-HQ-OAR-2021-0668-0133. The 2018 EIA 860 Report lists Dave Johnston Unit 1 as 105 MW. However, the 2019 – 2021 EIA 860 Reports list the generator summer net capacity value of Dave Johnston Unit 1 as 93 MW). Commenter (0554) asks the EPA to correct the capacity of Dave Johnston Unit 1 and adjust the associated allocations for Wyoming accordingly.

Commenter (0554) states although the EPA is not proposing retrofit technology breakpoints for combined cycle combustion turbines, the EPA is driving additional emissions controls for the combustion turbine units covered in Group 3 trading program that are not equipped with SCR retrofit control technology. Such units would have an incentive to reduce emissions consistent with the ozone season NO_X allowance price. The commenter's C.R. Wing Cogeneration Units 1 and 2 currently have steam injection for NO_X control and based on the review of the underlying data for the proposed rule, C.R. Wing unit-level ozone is reduced to 111 tons per unit equates to an average NO_X emissions rate of 0.108 lb/MMBtu for 2023 allocations and further reduced to 43 tons per unit equates to a NO_X emissions rate of 0.04 lb/MMBtu for 2026 allocations. However, this emissions rate does not agree with the table referenced in section 97.1010 (a)(3)(iii)(A) that lists an average emissions rate of 0.108 lb/mmBtu for C.R Wing Unit 1 and 2 (0.100 lb/mmBtu for Unit 1 and 0.116 lb/mmBtu for Unit 2). The EPA in its "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 EGU NO_X Mitigation Strategies Proposed Rule TSD, and "Combustion Turbine NO_X Control Technology Memo" states that "for combined cycle facilities originally built without SCR, if extra space in the HRSG was not dedicated for the future AIG and catalyst, it may be impossible to retrofit the facility with SCR." The commenter argues given the post-combustion retrofit constraints and that C.R. Wing Unit 1 and 2 contribute to only 0.15 percent of Texas state ozone season heat input, the EPA should revise C.R. Wing Cogeneration Unit 1 and 2 Ozone season 2026 allowances from 43 tons to 111 tons and adjust the state budget accordingly.

Commenter (0554) states that the EPA's modeling does not account for two Nevada Energy units (North Valmy 1 and 2) for which the current air permit requires cessation of operations no later than December 31, 2028, as part of the Regional Haze SIP. The corresponding baseline NOx emissions for Unit 1 are 609 tpy and 795 tpy for Unit 2. The EPA failed to account for these large units in its modeling, and hence it inaccurately determined that Nevada should be subject to the Proposed Rule.

Response:

For the final rule, the EPA updated its emissions inventories, updated its photochemical air quality modeling, and updated its assessment of emissions reductions availability for both EGUs and non-EGUs. Several comments here relate not to the emissions inventories used for air quality modeling at Steps 1 and 2 but rather to budget setting or allowance allocation methodologies at Steps 3 and 4. We will nonetheless address these comments here.

Comments regarding unit level characteristics in National Electric Energy Data System (NEEDS) or the Engineering Analysis are listed in the “Unit Specific Comments Log” included in the docket for this rulemaking. This log includes if data was changed based on the comment or, if not, why. Common reasons some comments did not result in changes were if the comments were about IPM outputs but did not identify any model inputs that were incorrect; and comments that confused NEEDS or IPM with the engineering analysis or unit level allocations.

Comments regarding the historical operation of Plant Daniel and the Mississippi emissions budget are discussed on Section VI.B.4 of the preamble. The EPA notes that according to data submitted by the operator to the EPA, Plant Daniel unit 2 did not operate during the 2021 ozone season.

Regarding the comment on the achievable emissions rate for combustion controls by fuel and boiler type, the EPA conducted analysis on this topic in the EGU NO_X Mitigation Strategies Final Rule TSD. See sections 4.2.1.4 and 10.6.1.4 of this response to comment document. See sections 4.2.1.4 and 10.6.1.4 of this response to comment document.

Regarding the comments on estimated emissions rates and heat input for the Delaware units in VII.B.3-1 of the proposal (DCR boilers and combined cycle units), the EPA notes that those estimates were used for state budget purposes (as EPA lacked historical data on the units). Delaware is not a state linked to a downwind non-attainment or maintenance receptor in this final rule and those values are omitted from this final action. The IPM file and corresponding EGU emissions inventory does include these units for the Rule’s Step 1 and 2 purposes, but those estimates are different than those in the cited Table VII.B.3-1 of the proposal – which were historical estimates and only used for proposed Delaware budget purposes (Step 3 and 4). Therefore, the data identified related to units in Delaware would only impact the EPA’s Engineering Analysis assessment conducted at Step 3 at proposal. The EPA explained in the preamble in Section IV that the EPA no longer identifies Delaware to be linked above 1 percent of the NAAQS threshold to any other state at Step 2 and did not conduct an updated Step 3 analysis for Delaware in the final rule.

The type of data identified related to units in Delaware would only impact the EPA’s Engineering Analysis assessment conducted at Step 3. The EPA explained in the preamble in Section III.C.1 that the EPA no longer identifies Delaware to be linked above 1 percent of the NAAQS threshold to any other state at Step 2 and did not conduct an updated Step 3 analysis for Delaware in the final rule. The EPA incorporated supportable updates to the version NEEDS used to develop the Updated Summer 2021 Reference case that was used as input to the IPM run used to support the Step 2 analysis for this action.

Regarding allocations for new units, including the Lowman Energy Center, the EPA used a standard set of assumptions to determine the additional emissions to add in for new units, as described in section B of the Ozone Transport Policy Analysis Final Rule TSD. In addition to modifying the size of the new unit set aside (NUSA), the EPA notes that initial allowance allocations do not represent an emissions limit for units.

The process for including emissions from non-ARP units in state budgets, specifically affecting the budgets for Nevada and Utah, is discussed in the preamble and the Ozone Transport Policy Analysis Final Rule TSD. In short, these units would not have a compliance obligation in 2023 because they will have until the start of the 2024 ozone season to install monitoring equipment. For the 2024 and 2025 years, the EPA estimated emissions for these units and these units would receive allowances from their state's NUSA. Starting in 2026, the dynamic budgets will reflect actual 2024 emissions for these units and they are henceforth treated as typical existing units.

Several commenters misinterpreted the initial allocation of allowances as a mass limit or an emissions rate limit. The initial allocation of allowances is not a limit on unit emissions; the initial allocations are just the portion of the state's budget that is freely allocated to the unit. Units can acquire additional allowances if they choose.

Several commenters appeared to confuse the budget setting process and the allowance allocation process. These processes, though related and using some of the same data, are distinct and the unit level emissions used in determining the size of a state's budget will not necessarily match the unit level allocations. A major source of the difference is that the state budgets are based on unit 2021 emissions, whereas the unit level allocations are calculated starting with the highest three of the last five years of heat input. Additionally, some units may see their allocations change year-to-year despite the unit's emissions rate in the budget setting process not changing. This is because as the state budget changes (for example, unit retirements or when reductions commensurate with SCR retrofits are phased in over 2026 and 2027), the number of allowances available to be allocated can change.

The EPA has clarified that in determining if units exceed the size cutoffs for SCR retrofits, it is using nameplate capacity. Net summer capacity is shown in the engineering analysis (Appendix A of the Ozone Transport Policy Analysis Final Rule TSD) because that data came from NEEDS, which uses net summer capacity. However, the EPA compared nameplate capacity and net summer capacity for each unit and found there is only one unit with the potential to receive an emissions rate commensurate with retrofitting an SCR, Dave Johnston unit 1, that has nameplate and net summer capacities that fall on different sides of the 100 MW cutoff. Since the nameplate capacity is above 100 MW, it received the SCR retrofit rate. (This plant is located in Wyoming, however, so this issue is not relevant to this final rule.)

The EPA included capacity factors, calculated by heat input and maximum heat input rate, in the proposal's engineering analysis for reference, but did not utilize that information. The unit capacity factor data has been removed from the final rule engineering analysis for clarity since it was not used in calculating budgets.

Under the modeling for the Final Rule, the EPA updated fleet input assumptions including retirements based on the latest available information. As such, North Valmy 1 and 2 are assumed to be retired prior to the 2028 run year.

Having addressed the unit level issues raised by commenters, comments concerned with reliability issues due to budgets being derived from that does not match the current state of the fleet are rendered moot. The EPA also addresses concerns of reliability and resource adequacy in Preamble section VI.B.1.d, the Reliability Assessment Final Rule TSD, and Section 10.4.

See Section 10.6.1.4 for response to comment regarding the combustion control performance rate and its robustness to different coal types.

Some commenters noted that the EPA's IPM modeling assigned emissions to non-emitting portions of combined cycle units and thought this was in error. This is not an error but a construct necessary to model the dispatch and emissions of combined cycle units correctly. To ensure the model dispatches associated combustion turbine (CT) and steam turbine (ST) portions of a combined cycle unit proportionally, as they physically must, they need to have the same emissions rate in the model. If they did not, the model could dispatch the non-emitting portion of the combined cycle unit, ignoring that the combustion portion must also operate. Therefore, the EPA calculates the emissions rates for each portion of the combined cycle unit such that they are equal and result in the correct total emissions. Because all the emissions happen at the same location, there is no impact on air quality modeling

Comment:

Commenter (0779) states EPA has incorrectly identified Talen's Brunner Island Units 2 and 3 as being natural gas units. They currently have the ability to burn coal, and often do, and any future NO_X allocations should reflect that baseline. Talen has installed natural gas burners in these units (like Brunner Unit 1) and will burn gas in future ozone seasons with year-round gas burning beginning after 2028.

Response:

The EPA is aware of the dual-fired nature of the units at Brunner Island. However, these units are required by consent decree to only burn natural gas during the ozone season. Therefore, for the purpose of the engineering analysis and setting state budgets, the EPA considered these units coal-to-gas conversions and accordingly reduced their 2021 ozone season NO_X emissions by 50 percent to create the 2023 – and other future years – engineering analysis baseline and treated the units as other O/G Steam units for the engineering analysis.

Comment:

Commenter (0411) asserts that Minnesota should not be included in the ozone season trading program. The commenter relates that Minnesota impacts only Cook County, IL, a Moderate ozone nonattainment area. The commenter believes the emissions inventory and the modeling techniques used by the EPA in modeling Minnesota's impacts were in error and if corrected and remodeled would yield a different result, with Minnesota no longer being included in the proposed program. The commenter relates that based on information provided in the MPCA's SIP Disapproval response, the EPA did not include 4,500 tons of ozone season NOx reductions from the Taconite industry, and this combined with planned coal unit retirements in the state that have either been proposed or have been approved by the Minnesota Public Utilities Commission represent more than the emissions reductions needed to meet the 2026 illustrative state emissions allocation. The commenter believes the EPA could identify these in the FIP as the needed reductions from Minnesota and eliminate the need for expanding the CSAPR Ozone Season Allowance Trading program to the state.

Response:

EPA reflected over 3 GW of known coal-fired retirements in Minnesota in its baseline modeling. This includes plants such as Taconite Harbor Energy Center, Sherburne County, Inver Hills, Hoot Lake, and Blue Lake Generating Plant. The EPA updated its inventory of retiring units based on comments on the proposal. These retirements can be found in Appendix A of the Ozone Season Transport Policy Analysis Final Rule TSD. The EPA notes that Minnesota, based on final rule modeling, was not linked in 2026 to a downwind nonattainment or maintenance receptor and is not subject to the control stringency pertaining to that year.

3.3.1.2 IPM Model Data Corrections

Comments:

Commenter (0511) notes that the Fort Martin NO_X rate and capacity factor used by the EPA in the IPM reference case are incorrect. For the 2023 case, EPA used an incorrect NO_X rate of 0.13 lb/MMBtu for Fort Martin unit 1 (it generally runs at approximately 0.28 lb/MMBtu at full load). Even with the operation of all of the installed controls (identified by the EPA as including SNCR and over-fired air), the IPM erroneously stated rate of 0.13 lb/mmBtu is not achievable. Additionally, the 2025 model results show both Fort Martin units with a capacity factor of zero for the ozone season. There are no business plans or market conditions that would support such an assumption. The commenter is concerned that these factors (the incorrect rate of 0.13 lb/mmBtu and the assumed capacity factor of zero), will result in the proposed West Virginia NO_X emissions budgets being incorrectly biased low.

Commenters (0341, 0397) and their members have analyzed the data underlying the model and have observed the flaws below that should be corrected and the proposed good neighbor FIP accordingly adjusted prior to promulgation of the final rule:

- Units Missing from the IPM Dataset for Kentucky
    - East Kentucky Power Company - John S. Cooper (ORIS 1384)
        - Unit 1 – Unit has no scheduled retirement date.
        - Unit 2 – Unit has no scheduled retirement date.
    - East Kentucky Power Company – HL Spurlock (ORIS 6041)
        - Unit 2 – Unit cannot convert to natural gas, nearest gas line is 39 miles away.
        - Unit 3 – Unit has no scheduled retirement date.
        - Unit 4 – Unit has no scheduled retirement date.
    - Kentucky Utilities - EW Brown (ORIS 1355)
        - Unit 3 – Unit has no scheduled retirement date.
        - Retired Units in the Dataset for Kentucky
    - Louisville Gas & Electric Company – Paddy's Run (ORIS 1366)
        - Unit 11 retired on March 31, 2021.
        - Permit Limits That Are Exceeded by Model
    - Louisville Gas & Electric Company – Paddy's Run (ORIS 1366)

        - Emissions for facility total 345 tons. The Title V permit (O-0125-18-V) set a federally enforceable limit of plantwide NO_X emissions to less than 100 tons during any 12-month consecutive period to avoid NO_X RACT and PSD/Nonattainment NSR that was established in 1998.
    - East Kentucky Power Cooperative [EKPC] (ORIS 55164)
        - Emissions for Bluegrass Generating facility exceed the plantwide limit set in the federally enforceable permit (V-16-018 R1). This limits plantwide NO_X emissions to 95 tons per calendar year from the generating units, natural gas heater, emergency generator and emergency fire pump.
        - Combined Cycle Combustion Turbines Emissions
    - Louisville Gas & Electric Company – Cane Run (ORIS 1363)
        - Stack 7S - All emissions should be contributed to the combustion turbines 7A and 7B.
    - Tennessee Valley Authority (TVA) – Paradise Fossil Plant (ORIS 1378)
        - Stack STG1 – All emissions should be contributed to the combustion turbines PCC1, PCC2 and PCC3.
        - UIEK also identified anomalies in the emissions modeled in the ozone season. The units plan to operate year-round and not just in the non-ozone season months.
    - Duke Energy – East Bend (ORIS 6018)
        - Unit 2 emissions were reduced by greater than 81 percent from previous IPM model and there is no modeled operation in the ozone season.
    - Big Rivers – D B Wilson (ORIS 6823)
        - Unit W1 indicate no modeled operation in the ozone season.

Commenters (0324,0344,398, 397) strongly advocate for the use of ERTAC over IPM to predict future generation and utilization. The commenter (0509) notes the EPA's modeling guidance notes that the EPA's preferred models (IPM) and its code cannot be proprietary. The EPA's use of IPM has resulted in Multijurisdictional Organizations Os) and states being forced to use alternative approaches for developing future year EGU emissions that are more transparent, stable and cost-effective such as the Eastern Regional Technical Advisory Committee (ERTAC). This lack of transparency from EPA prevents reasonably coherent feedback in the rulemaking process. Commenters (0344, 0346, 0361, 0385) argue the IPM is a flawed methodology being used to formulate state budgets with significant errors.

The current IPM forecast includes EGU retirements for units that are not scheduled to retire. The IPM data indicates that there is a significant amount of capacity in the ERCOT region that is idled on a year-round basis. However, many of the referenced generators have not been idled, and no announcements have been made indicating that these resources are anticipated to be idled. The ERCOT market is structured to incentivize the highest availability in the summer NO_X season due to the high demands that exist in the extreme hot temperatures in Texas. ERCOT does not have resources available to support the idling of significant amounts of capacity, particularly in the summer of 2023. While it is acknowledged that there are a significant number of solar assets in the interconnection queue, there is also evidence that solar projects are increasingly moving their interconnection dates further into the future as supply chain and labor shortages impact their ability to interconnect.

Commenters (0344, 0346) continue, the IPM erroneously assumes that the power market, before any impact from this rule, would see 2023 coal retirements of 32 units representing 9.7 GW of capacity. None of the owners of these 32 units have announced retirement for 2023. Table 9-7 from the National Rural Electric Cooperative Association (NRECA) technical report is flawed and condemns EPA's analysis to failure. Commenter (0344) states further, IPM forecasts generation shifting, but unit operators have no control to ensure such shifting would occur. The ERTAC model is updated regularly to account for actual planned shutdowns and account for where generation shifting will most like occur.

Commenter (0385) gives examples of flaws within IPM:

- The IPM data in the "base case" assumes that significant ERCOT capacity is idled on a year-round basis. Flaws in the base case necessarily render modeling results unreliable. Here, the IPM base case reflects idling of 42 coal units in 2023. But these generators have not been idled and no announcements have been made to that end.
- Concerns about mistaken EPA assumptions about retirement and idling of Texas coal plants have been expressed to EPA by San Miguel and NRECA in phone calls, emails, and meetings multiple times since 2011 (including intensive discussions in 2015, 2019, and 2021-22) with the most recent expression of concern contained in an April 5, 2022, letter from NRECA's Environmental Policy Council to EPA's Clean Air Markets Division.
- San Miguel is among the power generators that the EPA's IPM classifies as idled in the 2021 reference case for run years 2023, 2025, and 2030, but that in fact is not idled and does not plan to be idled under current conditions. Indeed, San Miguel has recently invested over $139 million in environmental controls, it is going through the state permitting process to expand its mining operations, and it otherwise plans to meet its contractual commitments to produce power through 2037.
- By removing generation by idling, IPM projects generation will be shifted to sources not covered by the Transport Rule FIP. The IPM neither accounts for the ERCOT market being structured to incent the highest availability in the summer ozone season due to the high demands that exist in the extreme hot temperatures in Texas, nor that ERCOT lacks resources to support the idling of capacity (particularly in the summer of 2023).
- EPA's ERCOT generation shifting analysis indicates that there is a degree of shifting that could occur among resources that would not cause undue reliability impacts. But that is based on unrealistic IPM assumptions. For example, as explained more fully in the South Texas Electric Cooperative's (STEC's) comments, the EPA's IPM assumes significant reductions from the Hidalgo Energy Center located in a South Texas region called the Valley. But the IPM does not acknowledge that the Valley has a bidirectional stability constraint, with both import and export problems that could lead to cascading outages and/or a blackout of the ERCOT system. The Valley Import constraint, where importing power into the Valley at times of high load and low renewable production can only be offset by increased thermal generation from assets located in the Valley, is

> unaccounted for in the IPM. There are only four thermal facilities in the Valley. Given continued load growth, the Hidalgo Energy Center is critical to the Valley. The assumed reduction of the Hidalgo Energy Center in the IPM results in significant threats to the reliability of the ERCOT system.

Commenter (0408) includes corrections to the EPA for the NEEDS database and IPM data. Commenter (0408) provided a table of corrections in Attachment 1 within their comment.

Commenter (0411) adds on September 15th, 2021, the Illinois Climate and Equitable Jobs Act was signed into law. The law targets a carbon-free power grid by 2045, closing all of the state's fossil fueled power plants through phased retirements. Starting in 2030, gas-fired sources must reduce carbon dioxide (CO_2) emissions below baseline (average annual tons emitted 2018-2020), private sector coal sources must have zero CO_2 emissions, and public sector coal sources must be reduced by 45 percent. The commenter states this program will have a significant impact on the state's native contribution to ozone yet was also not considered as part of this FIP, has not been incorporated into the IPM model, and has not been reflected in the photochemical modeling that is the basis for this FIP proposal.

Commenter (0521) adds the budget inputs associated with the IPM runs seem to indicate that the John Twitty Energy Center coal-fired units will be idled in CY2023 and CY2024, which is not the case.

Commenter (0557) states the model double-counts the impacts of modeled NO_X emissions reductions on downwind air quality receptors. The model relies on the EPA's IPM model base case and the EPA's engineering analysis. The inventories between the two models disagree, causing a flawed model output. The commenter believes the likely cause of the discrepancy are the substantial errors and omissions of units across the entire EGU fleet, including IPM idling units that are not really idled. The commenter then concludes the EPA did not properly assess whether its proposed controls are "necessary" to achieve attainment or eliminate linkage. These assumptions regarding Virginia's impacts on downwind monitors are incorrect to a large degree

Commenters (0323, 0336, 0541, 0545) are concerned about the EPA's failure to consider emissions control programs adopted after early 2021 that should be assessed for impact on nonattainment and therefore upwind significant contribution. Commenter (0541) specifies that significant steps have been taken in Alabama to reduce pollution from EGU sources since the base year the EPA used to project future contributions, including the addition of renewable and low emissions generation, conversion of coal units to natural gas, and the retirement and replacement of coal generation.

Commenters (0409, 0528) argue although the EPA has deference in its modeling choices, its model must bear a rational relationship to the characteristics of the data to which it is applied. *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 135 (D.C. Cir. 2015) (citing *Appalachian Power Co. v. EPA*, 135 F.3d 791, 802 (D.C. Cir. 1998)). Otherwise, use of the model is arbitrary and capricious. Here, using the Summer 2021 EGU inventory leads to results divorced from the reality of power demands between 2023 through 2032 and for maintenance of attainment beyond.

Commenter (0372) claims EPA's generation shifting model does not account for the realities of how markets operate. The commenter further claims that transmission lines not only shape the power sector but are further complicated by electricity markets – market rules are not standardized, and as a result create seams between the different constructs, causing friction with respect to the transfer of electricity. The commenter reports that there are four IPM regions in Kentucky: MISO Indiana, PJM West, Southeast Regional Council (SERC) Central Kentucky, and SERC Central TVA, and claims that the market rule for one (RTO) are not the same as another (PJM). In addition to the market-specific conditions, NERC also imposes market constructs on each of these regions – they must balance their load and generation second by second and not rely on neighboring systems [NERC BAL-001 and BAL-002].

Commenter (0372) disagrees with EPA's model assumptions that out-of-market generation assets can be dispatched in lieu of, for example, PJM assets; adding that the Agency assumes there is unlimited capacity in other markets, such as MISO. The commenter underscores the point that they must first preserves reliability for its system and ensures adequate transmission capacity for its members, and in the event that there is leftover capacity, it can be purchased by a non- member, assuming that there is enough available capacity for the transmission path, the non-member may purchase power for that path (*i.e.*, part of the transmission line). If the path is fully subscribed based on RTO member needs or otherwise, the non-member cannot make the reservation.

Response:

Responses to comments regarding specific unit's characteristics in NEEDS or the engineering analysis can be found in the "Unit Specific Comment Log" in the docket for this rulemaking. This log identifies whether the EPA made a change to data, if the EPA's latest data already matched what the commenter suggested, or if the EPA did not adopt the commenter's suggested changes. Where the EPA did not adopt changes based on these comments, the EPA provides an explanation.

The EPA disagrees with commenters who suggest the Integrated Planning Model (IPM) is an inadequate or unreliable modeling tool to analyze the power sector. We conducted the air quality modeling for the final rule incorporating updated EGU emissions projections (available at: https://www.epa.gov/power-sector-modeling/supporting-documentation-2015-ozone-naaqs-actions) reflecting fleet and other input updates as of Summer 2022, which also includes updates from commenters and through the pre-proposal request for input on our emissions inventories.

Several commentors suggested EPA replace its use of the Integrated Planning Model (IPM) with ERTAC. One commentor also suggested that ERTAC is more transparent compared to IPM. IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed,[42] multi-regional,

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[42] IPM has been peer reviewed periodically evaluating transparency of inputs and documentation, adequacy of modeling capabilities, and appropriateness of the modeling

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 almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. For the modeling used in support of the proposed disapprovals, the EPA has provided extensive documentation[43] of the input assumptions and methodology that go into the EPA's use of IPM. For this action, the EPA used an updated version of power sector modeling.[44]

Additionally, the EPA staff routinely meets with stakeholders to discuss IPM inputs and results, including comparisons to ERTAC. Therefore, the EPA finds IPM, including the versions of IPM projections used at proposal and final, is both transparent and well-suited to analyze EGU emissions while reflecting the impacts of changes to the EGU fleet, projected changes to electricity demand, changes in fuel prices, and state and federal policies as of Summer 2022.

We agree in general that ERTAC is similar to the "engineering analysis" approach that we have used for some transport applications, such as in the Revised CSAPR Update, in that both are designed to be more rooted in recent operating behavior. However, we observe that IPM is capturing much of this behavior while also accounting for additional economic-based operational changes that may be expected in the future.

The EPA's documentation includes all the detailed assumptions and data sources that are included as input that is underlying in the version of IPM that is used to help inform power plant air regulatory and legislative efforts for more than two decades. The model has been tailored to meet the unique environmental considerations important to the EPA - including various national (legislative), federal, and state level measures - while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the

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platform use for regulatory and strategic power sector analysis. The modeling platform and its documentation has consistently been found appropriate and adequate for regulatory analysis by the independent peer reviewers with a lot to commend. The IPM Peer Review of v6 and the Response to Peer Review can be found at: https://www.epa.gov/power-sector-modeling/ipm-peer-reviews

[43] https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference

[44] The updated Power Sector Modeling input data, results, and corresponding documentation used for this final action are available at https://www.epa.gov/power-sector-modeling/supporting-documentation-2015-ozone-naaqs-actions.

country. The EPA's goal is to explain and document the Agency's use of the model in a transparent and publicly accessible manner, while also providing for concurrent channels for improving the model's assumptions and representation by soliciting constructive feedback to improve the model. In addition to soliciting feedback, the EPA has also commissioned peer reviews, including of the latest version IPM v6. The recommendations from these peer reviews and the EPA's response are available on the EPA's website (https://www.epa.gov/power-sector-modeling/ipm-peer-reviews). These efforts include making all inputs and assumptions to the model, as well as output files from the model, publicly available on EPA's website and in the regulatory docket.

The EPA has and will continue to discuss modeling inputs and outputs of the IPM and ERTAC projections with any interested parties. We note some differences here. The EGU emissions from IPM are projected at the seasonal level based on economic dispatch, rather than historic behavior. These seasonal values are then temporally allocated (*i.e.*, post-processing IPM outputs based on historical emissions patterns) to create hourly emissions for use in the air quality modeling. The ERTAC tool assigns the hourly emissions utilizing historical emissions patterns based on different methods and makes different assumptions about which units will increase/decrease operation in individual hours based on historical operation. Consequently, even if the seasonal emissions estimates are identical between IPM and ERTAC on a state, regional, or even unit basis, the final hourly projected emissions will be different and have corresponding different effects on projected air quality. Consequently, when commenters state that ERTAC should be used rather than IPM, they may be preferring the hourly emissions utilized in ERTAC rather than that used by the EPA based on the seasonal IPM outputs and EPA's hourly temporal allocation methodology that is independent of IPM. These comments are not specific enough for EPA to make changes to the current temporalization methodology, which we continue to find sufficiently reliable to inform this action.

IPM creates a consistent nationwide projection and can account for effects of regulatory programs that may have differential effects on different units throughout the domain. For example, in IPM, emissions budgets reflect the Revised CSAPR Update, and account for the changes in unit dispatch relative to units that are not included in the program. The ERTAC tool, while well-refined and consistently updated for particular states or even regions (, LADCO)—and may be appropriately used for air quality modeling by those entities for those areas—is not necessarily appropriate for a nationwide assessment where consistent emissions projections and air quality modeling are necessary.

One commenter discussed a perceived "double-counting" of emissions reductions in the air quality modeling analysis. It seems the commenter is conflating IPM baseline projections, which are used as input to the air quality modeling in Steps 1/2, and engineering analytics which is used in Steps 3/4 along with AQAT to assess potential emissions reductions and emissions budgets. (A full discussion regarding the development of the EGU baseline projections used in the air quality modeling and the use of these tools is included in Section IV.A.2.a of the preamble). As discussed previously, modifications requesting corrections to EGU data that were incorporated to IPM's inputs and assumptions are discussed in the "Unit Specific Comments Log". Other updates to IPM's inputs can be found in the document "Updated Summer 2021 Reference Case Incremental Documentation for the 2015 Ozone

NAAQS Actions" (https://www.epa.gov/power-sector-modeling/supporting-documentation-2015-ozone-naaqs-actions).

As for commenters mentioning EPA's failure to consider states' control programs, the projections accounted for in EPA's analysis includes these control programs and requirements. As discussed previously, please see the "Unit Specific Comments Log" and the document "Updates in Power Sector Modeling Baseline Projections for 2015 Ozone NAAQS Actions"

In general, for comments such as these that focus on unit-level uncertainty and any discrepancies between unit-level projected versus eventual realized behavior (*e.g.,* comments on projected idled units), the EPA notes it is incorrect to simply extrapolate from the unit-level observation that a subsequent state or regional value needs to be changed. The EPA notes it uses best available data and reasonable assumptions (informed by commenter data) regarding the future at the time of analysis. It makes illustrative unit-level details available, before aggregating those values to use at the state and regional level. It is an exercise in projecting reasonable state-level and region-level totals, not an exercise that purports to predict the future of millions of operational variables at the unit-level. Any modeled (IPM or engineering analytics) residuals – which are the difference between a projected value and the eventual observed value – can cut both ways and are inherent in projecting. Due to the law of large numbers and the size of the fleet, these residuals are generally much smaller or mooted at the state and regional level as a result of their offsetting nature. It is not the case that each of these unit-level predictions must materialize in the future in order for the EPA's state and regional determinations to be valid. The EPA notes that its future year emissions inventories have millions of point estimates. Its IPM power sector modeling tool for EGUs (which make up 10 percent of the ozone-season NOx inventory) has over 20 million variables and over 1 million constraints. Its engineering analytics tool shows future year illustrative values for dozens of data fields for thousands of units. Consequently, the EPA notes that any tendency to conclude a system-wide deficiency as the result of a unit-level discrepancy – absent a systematic evaluation – can mislead; it is, essentially, cherry-picking. Where a commenter observes that there may be a certain unit-level discrepancy between the projection of a future value and what may actually occur in the future, this does nothing more than point out what is inherent in any modeling effort. It is not, on its own, grounds to reverse EPA's regulatory findings. *See EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 135-36 (D.C. Cir. 2015) ("We will 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.").

Comment:

Commenter (0317) states that the EPA failed to consider relevant information in its analysis. According to the commenter, several Arkansas units subject to SCR retrofits have federally enforceable obligations to cease unit operations, and these obligations are a matter of public record, well publicized and known to EPA. The commenter remarks that the EPA's failure to consider those closure dates have a material and substantial impact on the cost per ton of NOx removed and results in imposing overcontrol by not recognizing the NOx reductions that will occur as a result of those unit ceasing to operate. The commenter asserts that the proposed FIP also fails to account for ongoing reductions through 2026 for a variety of other factors including EGU retirements and changes in utility markets, *i.e.*, RTO loading patterns.

According to the commenter, inclusion of these factors in the analysis confirms that it is unnecessary to impose additional restrictions on the EGUs for states predicted to be linked to downwind maintenance receptors.

Response:

EPA's IPM modeling of the power sector captures both known and projected changes in the fleet to occur by 2026. These include actions such as announced retirements, state and local policies, expected changes in fuel market conditions, etc. The projected emissions future is substantially lower than recent 2021 levels and consistent with the sustained decline in emissions observed from the sector on average over the past decade; however, even accounting for these changes, we identify persistent ozone nonattainment and maintenance receptors in our modeling through 2026. The EPA uses robust and sophisticated modeling (consistent with all prior CSAPR Rules) to model this air quality future. This emissions inventory for EGUs is then combined with the broader emissions inventory to provide the inputs for the CAMx Air Quality modeling used at Step 1 and Step 2 to determine linkages.

In regard to the federally enforceable requirements and other known changes in the power sector, those are factored into both EPA's IPM and Engineering Analysis modeling. In some cases, these dates may occur after EPA's analytic period and so would not be relevant to an analytic year that occurs before such changes. The remainder of these comments are addressed elsewhere in the record.

Comments:

Commenter (0346) states their belief that the assumptions used to develop the EPA's IPM data are impractical – specifically, the EPA's generation shifting analysis for the ERCOT region of Texas falsely assumes that generation shifting would not cause reliability impacts. The commenter asserts that the proposed rule fails to acknowledge that West Texas generation is constrained due to transmission stability phenomena that, if violated, could lead to cascading outages and possibly a system-wide blackout. The commenter also firmly disagrees with the EPA's assertion that generation from West Texas is available to displace generation from the eastern part of the state is not accurate; noting that such generation shifting is not currently feasible and would require significant transmission buildouts to better interconnect West Texas generation to the load centers located in the eastern part of the state, which take years to plan and build. The commenter adds that the use of intermediate-resources (wind and water) were to be backed down to help maintain grid stability, that would serve to only increase the need for thermal generation in other parts of the state which would defeat the EPA's intention of reducing NO_X emissions. The commenter discusses the reductions assumed by the EPA at the Hidalgo Energy Center, and emphasizes that this power station, located in the Rio Grande Valley area, contains numerous inverter-based resources concentrated in a region with weak transmission connections to the remainder of ERCOT. The commenter points out that the connection to the remainder of ERCOT presents a bidirectional (to/from) stability constraint, but is most area of concerned is the Valley Import constraint – where importing power at times of high load and low renewable production can only be offset by increased thermal generation from assets located in the Valley, including the Hidalgo Energy Center; thus the assumed reduction by Hidalgo will result in significant threats to the reliability of the ERCOT system and possibly the nation's system as a whole.

In a similar comment, commenter (0346) disagrees with the EPA's assertion (regarding IPM data) that there is a significant amount of capacity in the ERCOT region that is idled on a year-round basis; stating that many of the referenced generators have not been idled, and no announcements have been made indicating that these resources are anticipated to be idled. According to the commenter, ERCOT does not have resources available to support the idling of significant amounts of capacity, particularly in the summer of 2023. The commenter agrees that there are a significant number of solar assets in the interconnection queue, there is also evidence that solar projects are increasingly moving their interconnection dates further into the future as supply chain and labor shortages impact their ability to interconnect. The commenter cites NRECA's comments, noting that NRECA also expresses concerns about EPA's IPM data – *e.g.,* believe that the EPA erroneously assumes that the power market, before any impact from the FIP, would see 2023 coal retirements of 32 units representing 9.7 GW of capacity; none of the owners have announced retirements for 2023.

Commenter (0385) argues that the EPA's IPM should not be used to justify the FIP from a grid reliability perspective because IPM grid simulations are not true reliability analyses, but rather a "resource adequacy" analysis, simply examining whether the total amount of electric capacity that will be forced to retire within broad regions will cause capacity levels to fall below regional reserve requirements. The commenter further contends that the IPM analysis does not simulate the actual grid, where system dispatch is impacted by localized transmission constraints, but instead, assumes that power flows freely within broad geographic regions unimpeded by bottlenecks or overriding local reliability considerations. According to the commenter, IPM data inherently includes assumptions that conflict with on-the-ground ERCOT realities. To illustrate the commenter provides 5 examples briefly mentioned below:

- The IPM data in the "base case" assumes that significant ERCOT capacity (42 coal units) is idled on a year-round basis. The commenter states that these generators have not been idled and no announcements have been made to that end.
- Concerns regarding assumptions made about retirement and idling of Texas coal plants have already been expressed to EPA by phone, email, etc., since 2011 with the most recent expression of concern contained in an April 5, 2022, letter.
- The EPA incorrectly classifies the power generator, San Miguel, as idled in the 2021 reference case for run years 2023, 2025, and 2030. According to the commenter, the power generator was not idled and does not plan to be idled under current conditions. The commenter underscores the point that San Miguel has recently invested over $139 million in environmental controls, it is going through the state permitting process to expand its mining operations, and it otherwise plans to meet its contractual commitments to produce power through 2037.
- The removal of generation by idling, will likely result in a shift of IPM projects generation to sources not covered by the Transport Rule FIP. The commenter states that the IPM neither accounts for the ERCOT market being structured to incent the highest availability in the summer ozone season due to the high demands that exist in the

extreme hot temperatures in Texas, nor that ERCOT lacks resources to support the idling of capacity (particularly in the summer of 2023).

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Commenter (0346) states their belief that the assumptions used to develop EPA's Integrated Planning Model ("IPM") data are impractical – specifically, the EPA's generation shifting analysis for the ERCOT region of Texas falsely assumes that generation shifting would not cause reliability impacts. The commenter asserts that the proposed rule fails to acknowledge that West Texas generation is constrained due to transmission stability phenomena that, if violated, could lead to cascading outages and possibly a system-wide blackout. The commenter also firmly disagrees with the EPA's assertion that generation from West Texas is available to displace generation from the eastern part of the state is not accurate; noting that such generation shifting is not currently feasible and would require significant transmission buildouts to better interconnect West Texas generation to the load centers located in the eastern part of the state, which take years to plan and build. The commenter adds that the use of intermediate-resources (wind and water) were to be backed down to help maintain grid stability, that would serve to only increase the need for thermal generation in other parts of the state which would defeat the EPA's intention of reducing NO_X emissions. The commenter discusses the reductions assumed by the EPA at the Hidalgo Energy Center, and emphasizes that this power station, located in the Rio Grande Valley area, contains numerous inverter-based resources concentrated in a region with weak transmission connections to the remainder of ERCOT. The commenter points out that the connection to the remainder of ERCOT presents a bidirectional (to/from) stability constraint, but is most area of concerned is the Valley Import constraint – where importing power at times of high load and low renewable production can only be offset by increased thermal generation from assets located in the Valley, including the Hidalgo Energy Center; thus the assumed reduction by Hidalgo will result in significant threats to the reliability of the ERCOT system and possibly the nation's system as a whole.

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Commenter (0395) states their belief that the Texas grid is disproportionately impacted by the proposed FIP; highlighting the fact that unlike other power markets in the U.S., the *e.g.,* ERCOT, a capacity market, operates solely within Texas. The commenter explains that within the ERCOT market generation units are paid only for the electricity provided, not for being available to provide generation, with the exception of ancillary services. The commenter states that the market determines whether a unit is financially viable and needed for reliability by pricing power higher during times of high demand relative to supply. If a unit is currently profitable in the ERCOT market, the commenter maintains that it is because that unit is necessary to the grid and has not yet been replaced by a more efficient unit.

Commenter (0395) states that the ERCOT market does not provide a way for generators to receive minimum rates for power, or to recoup the cost of emissions control equipment, and as a result, the commenter feels that the IPM model assumptions about who will install controls and who will be dispatched to market are not representative of ERCOT resources – *e.g.*, the IPM model run show that 8,997 MW in ERCOT will retire early as a result of this rule. The commenter announces that, in the case of the Texas market, there is likely no scenario where a unit idles during the summer but continues to operate during other seasons, rather these units will likely be shutdown.

Response:

As part of the updates to the IPM modeling to support the final rule, the EPA has made several key changes to reflect market conditions and commentor feedback. This includes preventing any incremental economic (projected) retirements in the 2023 run year, updating near term coal and natural gas input prices to reflect current elevated price environment and the incorporation of minimum annual capacity factor limits for fossil capacity operating in regions without formal capacity markets. As a result of these changes, coal capacity and dispatch in 2023 and 2025 remains higher, and the availability of economic coal to gas generation shifting is muted, as compared to the proposed rule. Moreover, the fuel price changes and imposition of capacity factor limits results in no idled coal capacity in ERCOT over the forecast horizon. Coal capacity factors in ERCOT are projected to average 79 percent in 2023 and 56 percent in 2025 as a result, and only 2 percent of operating capacity operates at the 10 percent threshold in 2025, and none operates at that level in 2023. Moreover, the EPA has also updated the budget setting methodology used to determine the ozone season emissions budgets at Step 3 to exclude IPM-calculated generation shifting. Finally, phasing-in of the backstop emissions rate on coal units that lack existing SCR controls through 2030 results in greater compliance flexibility relative to the proposal. To provide more information on IPM's resource adequacy projections for the scenarios analyzed under the RIA, the EPA has included a Reliability Assessment TSD as part of this rulemaking.

3.3.1.3 Claims of Incorrect or Overly Optimistic Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) Emissions Reductions Assumptions

Comments:

Commenter (0274) notes the EPA used Mode 2 emissions rates for Seward Generation (ORIS 3130) to set state budgets. Based on the NEEDS V620_active reporting platform, Seward Generation has been classified under the Mode 2 or 4 reporting category, meaning these units did not operate their SNCRs during the ozone season which is an erroneous assumption. Specifically, the 2021 calculated ozone season NO_X rates for Seward 1 and 2 were 0.111 and 0.116 lbs/mmbtu, respectively and EPA reset these emissions rates to 0.10745 for Unit 1 and 0.08784 for Unit 2 for determining the 2023 Pennsylvania State Budget. Based on EPA accepted 2021 emissions data Seward Generation had an actual 2021 NO_X emissions rate of

0.127 lbs/mmbtu. The commenter continues noting, that in addition to the NO_X emissions rates referenced, and as reported on the Energy Information Administration's Annual 923 report, Seward Generation reported the annual operating hours that the ammonia injection system was operational, and these hours for Seward 1 and 2 were 6,855 and 6,924 respectively for the 2021 operating year. More specifically, the operating hours that the SNCR was in service for Seward 1 and 2 during the 2021 ozone season were 3,310 hours. Commenter (0274) asks EPA to reevaluate the reported operational control status as well as any emissions values for 2021. Based on the results of that reevaluation, commenter (0274) would ask that any changes be included and sent to Pennsylvania to aid in the state budget setting process.

Commenter (0283) states the assumption that years with lower emissions rates must have been due to use of existing SNCR controls is incorrect. SNCR is used to meet current NO_X limits at MPU when other factors result in an increased NO_X emissions rate. These factors include: increased energy demand resulting in increased and more variable unit MW generation requirements, changes to fuel composition necessary to combust more renewable fuels, and operation time between scheduled maintenance outages.

Commenter (0336) states in the spreadsheet entitled, proposal-appendix-a-proposed-rule-state-emissions-budgetcalculations-and-engineering-analytics.xlsx, tab "Unit 2023", the data for ORIS 3809, Yorktown Power Station, Boiler 3, shows that this unit's tonnage was calculated based on a NO_X rate of 0.019 lbs/mmBtu. The 2019-2021 average NO_X rate for this unit was 0.162 lbs/mmBtu. The unit is a 790 MW boiler firing residual oil. The 2019- 2021 average ozone season NO_X emissions for the unit is 50.9 tons (72.1 tons in 2019, 42.9 tons in 2020, and 37.7 tons in 2021 based on Clean Air Market Division's information). The commenter states in the Ozone Transport Policy Analysis Proposed Rule TSD, Table B.1. indicates that oil/gas units greater than 100 MW and with an average emissions rate of at least 150 tons of NO_X for the 2019, 2020, and 2021 ozone seasons would be subject to SCR retrofits. However, this unit does not fit that category since its average NO_X mass emissions for 2019-2021 was under 150 tons. Commenter (0336) requests EPA to clarify why the NO_X emissions for this unit in 2023 were based on a controlled rate of 0.019 lbs/mmBtu or update the spreadsheet to apply the 0.162 lbs/mmBtu NO_X rate in 2023.

Commenter (0361) states the projected emissions reductions for SNCR systems produced by the EPA—both in their modeling assumptions and in their discussion of such systems in the proposed rule—is also unrealistic. In the commenter's experience with its WWVS units, for example, actual emissions reductions with the SNCR system were significantly less than EPA's projections. If other units are similarly underassessed, the result would be a significant shortfall of necessary allowances. The overassessment of the effectiveness of SNCR systems also undercuts the relative benefits associated with the cost of installing or activating those systems. The commenter argues this undermines the assertion that intervention is within EPA's purview in this case.

Commenter (0366) states in setting Ohio's emissions budget for 2023 and 2024, the EPA determined that Rolling Hills EGUs CT -1 and CT-2 currently are controlled with SCR systems. During original construction, Rolling Hills initially equipped CT-1 and CT-2 with SCRs, however application of hot SCR technology in peaking units was unproven and ineffective at that time (2003 timeframe) given the high exhaust temperatures as compared to

CCGTs. Rolling Hills CT-1 and CT-2 ultimately decommissioned the SCR equipment over ten years ago such that the SCR systems and the controls can no longer operate. The cost to bring the decommissioned SCR systems online for future use far exceeds estimates EPA provides for restarting idled SCR systems. Moreover, Ohio Environmental Protection Agency (Ohio EPA) removed permission to use SCR from Rolling Hills' Title V permit. Since emissions from CT-1 and CT-2 are below EPA's 150 tpy threshold for SCR cost-effectiveness, the CT-1 and CT-2's budget allocations should be computed without the application of SCR.

Commenter (0366) continues, in setting the emissions budget for New York, the EPA concluded that Arthur Kill Unit 20 could cost-effectively control NO_X with SCR based on the high, 3-year average emissions rate of 151 tpy just above EPA's SCR applicability threshold of 150 tpy. The commenter asks that the EPA examine the data more closely for Arthur Kill Unit 20 and consider the fact that this emissions unit is a peaking unit. Upon examination, the EPA will find that NO_X emissions and dispatch for 2021 exceeded any historical year of operations and is the driver behind only slightly exceeding the 150 tpy applicability threshold. The EPA based its cost-effectiveness calculations for oil/gas steam EGUs assuming a 0.14 lb NO, MMBtu input rate and decreasing to rates of 0.03 lb NO_X/MMBtu following control installation. Arthur Kill Unit 20's current uncontrolled emissions rate is based on an average NO_X input rate of 0.071 lb NO_X/MMBtu. Assuming a removal efficiency of 80 percent, installation of a SCR would generate only 120 tons per year of NO, emissions reductions. The commenter notes this figure is comparatively small when considering other EGUs with higher uncontrolled emissions rates or higher capacity factors can achieve well over 300 tpy of NO, emissions reductions by installing SCR.

Commenters (0372, 0409) argue there are incorrect assumptions as to NO_X emissions rates for SCR and non-SCR units sharing a common stack. NO_X emissions rates were not accurate with respect to natural gas conversions. There are emissions rate errors for common stacks, based on invalid assumptions. Commenter (0372) provides a table within their comment showing 2021 Unit Emission SCR Emission Rates (lbs/MMBtu). EPA incorrectly assigned a NO_X emissions rate for Cooper Unit 1 (Non-SCR unit) of 0.193 lb/mmBtu and Cooper Unit 2 (SCR unit) of 0.107 lb/mmBtu. Commenter (0372)'s accurate individual unit NO_X emissions are 0.46 lbs./mmBtu for Unit 1 and 0.06 lb/mmBtu for Unit 2 for the 2021 Summer Ozone Season.

Commenter (0372) notices the units are assumed to have functional SCRs when these units do not. The units are then assigned a lower NO_X rate assumption earlier than is achievable. With respect to the commenter's units in the Kentucky State Budget, the Base Case incorrectly assumes that Bluegrass Units 1 and 2 have functional SCRs. The SCR equipment in place has never been capable of functioning, as previously discussed. A substantial project would be required to install functional SCRs on the units. The emissions rates for these units must be adjusted.

Commenter (0521) notes that the City Utilities of Springfield, Missouri has no plan to install a SCR on its natural gas peaking combustion turbine at the John Twitty Energy Center. These turbine engines typically operated during peak demand periods or when called on by the Southwest Power Pool (SPP). The John Twitty Energy Center CTIA is not equipped with an SCR. The commenter notes the John Twitty coal-fired units (*i.e.*, Units 1 and 2) are controlled using SCRs and remain a vital capacity resource for both City Utilities and the SPP. These base-loaded units are critical to the reliability and affordability to City Utilities' customers, since Springfield/Greene Co. is positioned at the end of the SPP transmission line toward the east between the Midcontinent Independent System Operator (MISO) and Associated Electric. The commenter stresses if the model inputs are inaccurate, the proposed states' allocations are incorrect. These incorrect assumptions should be revised and technically justified before finalizing the FIP, including the reduction of seasonal NO_X Budget Allocations for the state of Missouri.

Commenter (0554) states the SCR optimization column, and in Nevada's case, all following columns, shows a reduction potential in tons for varying levels of technology inclusion. The Nevada value shown is 66 tons. Table VI.C.1-1 is misleading as the technology column headings refer to "potential" reductions. However, in Nevada's case, the 66 tons listed is the sum of all current units with SCR controlled to 0.08 lb/mmBtu or less. The commenter believes these reductions have already been realized and should not be subtracted from the Nevada budget. As a result, the new and correct baseline for Nevada should be 2,523 tons, which is the sum of the proposed baseline (2,346 tons), the missing Fort Churchill Unit 2 emissions (111 tons), and potential reductions (66 tons). Additionally, the 2014 Wyoming Regional Haze SIP required installation of SCR on Jim Bridger Units 1 and 2 by December 31, 2022, and December 31, 2021, respectively. However, current orders by both Wyoming and EPA authorize continued coal-fired operation of these units in 2023 and subsequent revision of the Wyoming SIP to reflect future conversion to natural gas. The commenter requests the 2023 allocations be adjusted to reflect coal-fired operation.

Response:

Responses to comments regarding specific units' characteristics in NEEDS or the engineering analysis can be found in the "Unit Specific Comment Log" in the docket for this rulemaking.

In regard to comment on the Manitowoc unit's potential emissions rate with SNCR optimization, the relevance of commenter 0283's observations is not clear. However, the EPA notes that the assumed emissions rate is within technology capability and the demonstrated emissions rate observed at the unit over the past five years (2017 – 0.039 lb/mmBtu, 2018 – 0.033 lb/mmBtu, 2019 – 0.045 lb/mmBtu 2020 – 0.08 lb/mmBtu, and 2021 – 0.082 lb/mmBtu). The SNCR performance rate is informed by historical data and is used to derive a state-level budget.

In response to comments regarding the emissions rates assigned units that share common stacks in the engineering analysis, see Section 4.2.1.4 of this response to comment document.

Finally, the EPA is including EGUs that may fire biomass in this rule consistent with the applicability criteria for EGUs used in prior CSAPR rules.

3.3.1.4 State-Specific Integrated Planning Model (IPM) Model Errors

Comments:

Commenter (0340) states EPA's use of their IPM model makes assumptions about the operation of EGUs in Kentucky, frequently in error. Many times, IPM has included units that are retired and have no emissions, or it has inappropriately retired units that have no plans to do so. Still, Kentucky utilities have continued to meet the ozone season NO_X budgets imposed by the EPA. Since 2003, Kentucky EGUs have reduced ozone season NO_X emissions by over 76 percent. In that same time period, none of the downwind monitors linked to Kentucky in the proposed rule have achieved attainment or maintenance status. Furthermore, beginning in 2014, those monitors' DVs have remained relatively flat, while Kentucky EGU NO_X emissions continued to decrease over 56 percent. While the EPA's modeling continues to identify contributions from Kentucky that exceed EPA's threshold of 1 percent of the ozone NAAQS, the emissions data and downwind air monitoring values indicate that Kentucky EGU ozone season NO_X emissions have very little, to no, impact on the measured concentrations and DVs at the linked downwind monitors. The commenter recommends that the EPA re-evaluate the use of their model for determining projected future year ozone DVs and upwind state contributions to linked downwind monitors. Kentucky also recommends that the EPA re-evaluate the use of a 1 percent contribution threshold as "significant" to downwind monitors.

Commenter (0397) states EPA's reliance on IPM at various points in the process undermines the credibility of EPA's rulemaking efforts. States like Oklahoma Department of Environmental Quality have had to drill down into EPA's analysis and have found flaws with IPM that were not flagged by the EPA. The EPA's lack of transparency about the inconsistencies resulting from use of the IPM is concerning. This is especially so because in many cases, states and other interested parties have had to divert time and resources away from other important tasks to uncover flaws in the EPA's analysis that the EPA should have caught and divulged on its own. The commenter also notes the proposed FIP, its supporting documentation, and the tools the EPA used to determine the emissions reductions that would be required by Oklahoma electric utilities, concerns arose regarding the calculations performed by the AQAT. One calculation in particular uses EGU sector emissions projected for 2026 and DVs generated by CAMx in that year to estimate the effects of a particular reduction in NO_X emissions on the ozone DVs at downwind monitors. The commenter used a future year baseline EGU emissions estimate for 2026 based on an EPA engineering analytics approach rather than the value computed by IPM. The engineering analytics approach yielded 2026 ozone-season EGU NO_X emissions of 10,467 tons in contrary to 2,407 tons predicted by IPM.

Response:

See preamble Section V.D and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for the EPA's overcontrol analysis, where the EPA demonstrates that the rule does not overcontrol any states (including Kentucky and Oklahoma) that are included in the rule. The EPA has updated both its IPM platform and its unit-level input assumptions to the platform in the NEEDS database for this final rule based on comment. In the 2026 base case the total EGU point inventory based on IPM for Oklahoma was 6,907 tons while in engineering analysis, the total was 10,260 tons (see the "2026_OS_NOx" worksheet within the Ozone_AQAT_final.xlsx Excel workbook). In both IPM and engineering analysis base, the state remains "linked" to a downwind receptor, affirming that Oklahoma significantly contributes to nonattainment and/or interferes with maintenance is robust to the EGU inventory utilized. The same conclusion also applies to Kentucky. Within the Step 3 air quality assessment, the EPA utilized the engineering analysis values at each level of stringency, again finding that Kentucky and Oklahoma significantly contribute and that there is no overcontrol. See preamble Section IV.C for EPA's discussion of why IPM and engineering analysis are used at the various steps of the transport framework and the implications for using each at the various steps. The EPA disagrees that the effects of this rule are "vanishingly small" or "not meaningful." As described in Section V.D of the preamble, there are meaningful improvements in ozone levels at the identified receptors under the emissions control strategy of the final rule to eliminate significant contribution. For many receptors, this rule alone will make substantial progress toward achieving attainment (as further discussed in the Air Quality Modeling Final Rule TSD and the Ozone Transport Policy Analysis Final Rule TSD). (We also note that, as disclosed in the RIA for executive order-compliance purposes, the monetized benefits are significant and well exceed the anticipated cost of the rule.) For a discussion of the Step 2 threshold, which is comprised of the contributions from all sectors (not just EGUs), see the preamble Sections III.B and Sections IV.F.1 and IV.F.2.

As described above in Section 3.3.1.2 (IPM Model Data Corrections) regarding interactions with the states using the ERTAC model, the EPA's use of IPM is thoroughly documented and undergoes peer-review. Furthermore, the EPA conducts regular meetings with stakeholders to present results from the IPM and solicit feedback.

3.3.2 Non-EGU Point Sources

3.3.2.1 Claims that Updated data should be used in Emissions Inventories

Comments:

Commenter (0517) requests that the EPA use 2017 NEI data for all non-EGU point sources as well as for the oil and gas sector point sources. They argue the NEI data are more representative of actual facility emissions.

Commenters (0324, 0332, 0359, 0513, 0518, 0519, 0547, 0758) elaborate while EPA's updated modeling accounts for certain updates between 2014 and 2016 in developing its baseline emissions inventory for 2016, 2016v2 does not capture enforceable emissions limits and emissions reductions from 2016 to present in modeling emissions in 2023 and 2026. These emissions reductions significantly impact EPA's assessment of nonattainment and maintenance-only receptors in these future years, and call into question EPA's determination that Kentucky, Texas, Oklahoma, and Nevada are linked. Additional states, including Missouri, Illinois, Wyoming, and Ohio, also suffer from similar modeling errors. Commenter (0518) indicates updated actual emissions data is available for non-EGU sources (*e.g.*, data from sources subject to monitoring and reporting under 40 C.F.R. part 75) and should be compiled and used for a rulemaking with the broad and unprecedented reach of the proposed rule, rather than relying on projections of data from almost a decade ago at these key stages. Commenter (0547) argues Wyoming has experienced significant reductions in NO_X since 2016. These reductions should be factored into EPA's model.

Commenters (0323, 0336, 0541, 0545) contend that the revised CSAPR update modeling contains an outdated emissions inventory that did not account for any on-the-books control programs adopted after 2019 and does not reflect the updated emissions inventory that was used by the EPA to assess Step 1 and 2 issues in connection with the current proposal. With ongoing efforts to manage and balance timely programs directed at nonattainment in upwind and downwind states, it is objectionable that there are no provisions for consideration of enforceable programs that will impact compliance with the NAAQS after "early" 2021.

Commenter (0764) specifies examples of the errors include units that no longer exist, stack locations that are off by more than a mile, and unexplainable velocity values. For example, EPA modeled near-zero velocities for the Boilers and BRU Scrubber at Albemarle's Magnolia, Arkansas facility and for several Georgia-Pacific units.

Response:

The EPA concurs with the suggestion by commenters to use 2017 National Emissions Inventory (NEI) data to the extent possible to represent 2016 instead of data projected from 2014. The EPA implemented this approach in the 2016v3 platform for point sources where a matching source could be identified in the 2017 NEI; however, data submitted specifically for the year 2016 were used, where available.

The EPA also updated the approach for developing 2023 non-EGU point source emissions in the 2016v3 platform to make use of 2019 NEI point source data as the basis for 2023 non-EGU point source emissions for sources not related to oil and gas production, as 2019 was the latest complete point source inventory at the time of the modeling. The state, local, and tribal agencies have the opportunity to use 40 C.F.R. part 75 data when developing the year-specific emissions that are submitted to the NEI. The 2026 emissions were derived from the 2023 emissions using industry-specific adjustment factors based on the AEO 2022 along with reductions from control factors resulting from known closures and control programs. Oil and gas-related non-EGU sources were first projected to the year 2021 using factors based on historical data, and were then projected to 2023 and 2026 based on predicted changes in oil and gas production and recent exploration levels. Projection methods including the control programs applied are explained in detail in the 2016v3 Emissions Modeling TSD in the docket for this action. It is the EPA's standard practice to only consider emissions reductions from rulemakings that have been finalized and a number of programs cited by the commenters have not been finalized.

Regarding the inclusion of control programs after 2019, many of the programs cited by the commenters are for EGUs. These are addressed in Section 3.3.1 above. Known control programs for non-EGUs were also reflected in the modeling inventories as discussed in the 2016v3 Emissions Modeling TSD.

Regarding the comment on errors in emissions and stack parameters for some units at the Crossett facility, the Emissions Inventory System (EIS) is used to collect the data for the NEI and state, local, and tribal agencies have a responsibility to maintain the status of the sources under their purview in EIS. Sources that were marked permanently shut down were not included in the projected 2023 and 2026 emissions. To prepare the 2023 and 2026 emissions, the data in EIS are supplemented with closures and control information obtained from other sources such as feedback from inventory data submitters and public comments, and also include the projected impacts of regulatory programs. The Domtar PB1 referenced by the commenter was marked closed in 2021 and is not included in the 2023 or 2026 inventories. The Crossett recovery furnace 8R and 10A boiler mentioned by the commenter as retired are included in the 2016v3 modeling inventories because they have not been marked as shutdown in EIS and their permits are still active through September 23, 2024.[45] The EPA reviewed the locations of the Lime Rotary Kilns with mapping software and found two of the locations to be correct and one was about 400m from the source but within the same AQM grid cell. Because the modeling grid cells are 12 km by 12 km, this would not impact the modeling results in any substantive way.

The stack velocities at Magnolia were reviewed but these are small sources and we note that commenter did not supply information indicating that a different velocity should have been used. The scrubber velocity was 0.955 ft/s but the source had only 24 tpy of NOx in 2026 and the Magnolia boiler with a velocity of 0.1 ft/s had a diameter of 7 ft and 86 tpy of NOx in 2025. The low velocities will cause the initial plume rise to be low, but given the modest size of the sources the emissions would still be released in layer 1 of the air quality model even if higher velocity assumptions were used (which, again, the commenter has not substantiated), and therefore the difference would not impact the modeling results in a notable way.

3.3.2.2 Consent Decrees Should be Reflected in Emission Inventories

Comments:

Commenter (0513) provides further detail on Kentucky, Texas, Oklahoma, and Nevada's NO_X reductions since 2016. The commenter provided reduction data in Tables 3-10 within their comment.

- Kentucky: Since 2016, at least three Kentucky facilities have entered consent decrees requiring enforceable NO_X emissions reductions totaling nearly 815 tpy. The EPA's determination that Kentucky is linked to downwind air quality problems fails to account for these enforceable emissions reductions because they fall outside EPA's 2016v2 modeling update. Commenter (0513) believes that the marginal link between Kentucky and downwind receptors has been eliminated by these additional enforceable emissions reductions. Kentucky's maximum contribution to these receptors is 0.18 ppb above EPA's 0.70 ppb linkage threshold. Because Kentucky's modeled contribution to downwind receptors is so low, even a small reduction in projected emissions could reduce Kentucky's level of contribution to these receptors below the 0.70 ppb threshold. Accordingly, commenter (0513) urges the EPA to account for these additional NO_X

[45] Operating Air Permit number 0597-AOP-R25 Issued to Georgia Pacific Crossett LLC by Arkansas Division of Environmental Quality on October 24. 2022.

reductions in determining whether to include Kentucky in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.

- Texas: Since 2016, at least ten Texas facilities have entered consent decrees requiring enforceable NO_X emissions reductions totaling more than 8,244 tpy, apart from additional reductions that the EPA has not quantified. EPA's determination that Texas is linked to downwind air quality problems fails to account for these enforceable emissions reductions because they fall outside EPA's 2016v2 modeling update. Commenter (0513) believes that the marginal link between Texas and downwind receptors has been eliminated by these additional enforceable emissions reductions. Texas' maximum contribution to these receptors is 1.11 ppb above EPA's 0.70 ppb linkage threshold. Even a small reduction in projected emissions could significantly impact this projected contribution. Further, the EPA's definitions of nonattainment and maintenance-only receptors acknowledge that slight changes in emissions contributions may impact EPA's determination that the listed receptors will experience air quality problems in 2023. For example, based on EPA's projected maximum DV, as little as a 3.7 ppb total change in NO_X emissions concentration would resolve air quality problems at the most impacted receptor—let alone the receptors to which Texas is purportedly linked by the slimmest of margins. Accordingly, Commenter (0513) urges the EPA to account for these additional NO_X reductions in determining whether to include Texas in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.
- Oklahoma: Since 2016, at least two Oklahoma facilities have entered consent decrees requiring enforceable NO_X emissions reductions totaling more than 1,000 tpy. The EPA's determination that Oklahoma is linked to downwind air quality problems fails to account for these enforceable emissions reductions because they fall outside the EPA's 2016v2 modeling update. Commenter (0513) believes that the marginal link between Oklahoma and downwind receptors has been eliminated by these additional enforceable emissions reductions. Oklahoma's maximum contribution to these receptors is 0.49 ppb above the EPA's 0.70 ppb linkage threshold. Because Oklahoma's modeled contribution to downwind receptors is so low, even a small reduction in projected emissions could reduce Oklahoma's level of contribution to these receptors below the 0.70 ppb threshold. Further, the EPA's definitions of nonattainment and maintenance-only receptors acknowledge that slight changes in emissions contributions may impact EPA's determination that the listed receptors will experience air quality problems in 2023. For example, based on the EPA's projected maximum DV, as little as a 2.4 ppb total change in NO_X emissions concentration would resolve air quality problems at the most impacted receptor—let alone the receptors to which Oklahoma is purportedly linked by the slimmest of margins. Accordingly, commenter (0513) urges EPA to account for these additional NO_X reductions in determining whether to include Oklahoma in the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards.
- Commenter (0519) provides addition information on Oklahoma's NO_X reductions. They believe the marginal link between Oklahoma and downwind receptors (if it existed) has been eliminated by enforceable emissions reductions that have been put in place within

the last five years and, thus, are not accounted for by 2016v2 update. Using EPA's 0.70 ppb linkage threshold, Oklahoma's maximum contribution above EPA's threshold to these receptors is just 0.49 ppb. Oklahoma contributes 1.19 ppb to Receptor 481210034 in Denton Cowity, Texas and 0.75 ppb to Receptor 170310032 in Cook County, Illinois. The maximum contribution was calculated by subtracting EPA 's linkage threshold (0.70 ppb) from each of these contribution values (1.19 ppb and 0.75 ppb), and then choosing the maximum value (from 0.49 ppb and 0.05 ppb, respectively). Since 2016, at least two Oklahoma facilities have entered consent decrees requiring enforceable NO_X emissions--totaling more than 1,000 tpy of NO_X reductions. Because Oklahoma's modeled contribution to downwind receptors is so low, even a small reduction in projected emissions could reduce Oklahoma's level of contribution to these receptors below the 0. 70 ppb threshold.

- Nevada: Since 2016, at least fifteen Nevada facilities have entered consent decrees requiring enforceable NO_X emissions reduction totaling at least 1,676 tpy, apart from additional reductions that the EPA has not quantified. EPA’s determination that Nevada is linked to downwind air quality problems fails to account for these enforceable emissions reductions because they fall outside EPA’s 2016v2 modeling update. Commenter (0513) believes that the marginal link between Nevada and downwind receptors has been eliminated by these additional enforceable emissions reductions. Nevada’s maximum contribution to these receptors is 0.19 ppb above EPA’s 0.70 ppb linkage threshold**.** Because Nevada’s modeled contribution to downwind receptors is so low, even a small reduction in projected emissions could reduce Nevada’s level of contribution to these receptors below the 0.70 ppb threshold. Accordingly, Commenter (0513) urges EPA account for these additional NO_X reductions in determining whether to include Nevada in the Federal “Good Neighbor Plan” for the 2015 Ozone National Ambient Air Quality Standards.

Response:

The Agency has updated its emissions inventories for the 2016v3 modeling used in the final rule to reflect commenters’ input regarding likely emissions levels at a variety of identified sources. In many cases, this information was readily ascertainable and could be included in the modeling inventories. Commenters also cited a host of enforcement settlements and consent decrees and made representations regarding the effect of these agreements on sources’ emissions levels. The Agency was unable to track down and verify these assertions in all cases in time to have such updates included into the emissions inventories for modeling. Claims regarding a level of emissions change due to a new control or agreement regarding emissions performance must be evaluated in comparison to a baseline, and commenters generally did not supply adequate information regarding the baselines from which the reductions they asserted were occurring. As such, in several cases, we were unable to verify whether the emissions inventories for 2023 and 2026 fully captured the claimed reductions. Nonetheless, based on our further evaluation of the specific cited agreements provided by commenters, we can confidently conclude that even had the full amount of the claimed difference in emissions been included, it would not have changed the outcome of the air quality modeling. We will review these specific claims in turn.

Regarding one commenter's statement that the EPA has not quantified emissions reductions for facilities subject to consent decrees in Kentucky, one of the listed reductions in NO_X is noteworthy at 800 tpy for Kosmos cement (while the others have less than 15 tpy impacts on NO_X). The total modeled NOx emissions for the Kosmos cement facility in 2023 is 1,270 tpy and in 2026 is 1,296 tpy. This is substantially less than the 2016 NO_X emissions of 2,121 tpy and well within the permitted values of 2,906 tons per year in the Louisville Title V Operating Permit no: O-0060-19-V(R1). This indicates that the impacts of the consent decree case that concluded 11/29/2016[1] are reflected.

Regarding commenter's statement that the EPA has not quantified emissions reductions for ten consent decrees issued since January 2016 for facilities in Texas, the commenter provided estimated NOx reductions for six of the consent decrees. The EPA reviewed the modeled emissions at the referenced facilities for which estimated impacts were provided. Estimated impacts for the remaining facilities were unknown and there was not enough information provided by the commenter for the EPA to determine the prospective impacts. The Guardian Industries Corsicana, TX facility is one of the facilities impacted by a consent decree[2] that was finalized in early 2016, although the impacts of the consent decree at the specific Guardian facilities in seven states were not clear. The modeled emissions at the Corsicana facility are 1,246 tpy NO_X in 2023 and 1,291 tpy in 2026. These emissions are lower than the 2016 NO_X emissions of 1,374 tpy and are, in the EPA's judgment, a reasonable representation of emissions from these facilities in 2023 and 2026. The commenter estimated a reduction of 658 tpy at the Cabot Pampa plant, which emitted 1,037 tpy NO_X in 2016 and had modeled emissions of 383 tpy in 2023 and 384 tpy in 2026, reflecting a reduction of 653 tpy in 2023 and 652 tons in 2026. This indicates that the Cabot Pampa consent decree is reflected in the analytic year modeled emissions.

The commenter estimated that the impact of the consent decree at the Cemex Odessa facility finalized July 11, 2018[3] was 1615.5 tons. In 2016, the total emissions at the facility were 1,396 tpy, which is less than the total estimated impact of the consent decree claimed by commenter. The total emissions modeled in 2023 were 867 tpy and in 2026 were 941 tpy, reflecting a reduction from the 2016 levels of 400-500 tpy. The EPA concludes that some reductions from the decree were reflected in the modeling, although it is unclear whether the full implementation was reflected. The EPA notes that to reflect the full implementation of the CD as described by commenter, as compared to the 2016 emissions, there would be no emissions remaining, which seems unlikely if the facility continues to operate.

The commenter estimated that the impact of the consent decree at the Continental Carbon Sunray Plant was 530 tpy NO_X .[4] The NO_X emissions for this facility in 2016 were 289 tpy and the modeled emissions for 2023 and 2026 were 279 tpy and 285 tpy, respectively. Given that the level of estimated reduction is over 250 tpy larger than the actual emissions, it would not be possible to achieve a reduction of 530 tpy – the largest achievable reduction if the emissions were totally eliminated would be on the order of 280 tpy.

The commenter estimated that the consent decree for the Big Spring and Borger Carbon Black Plants dated 8/14/2018 would be 656 tpy[5]; the consent decree impacted two facilities in Texas and one in Louisiana. The total 2016 NO_X emissions for Big Spring and Borger were 1703 tpy. The modeled 2023 emissions were 1658 tpy and the modeled 2026 emissions were 1,727 tpy. This consent decree may not be reflected in the modeled emissions.

The commenter estimated that the consent decree for Lehigh Cement Waco dated 11/18/2020 would be 133 tpy.[6] The 2016 emissions were 369 tpy and the modeled emissions in 2023 were 350 tpy and 372 tpy in 2026. This consent decree may not be reflected in the modeled emissions.

Thus, for the Texas consent decrees it appears that the following reductions may have been missed in the future year modeling: a maximum of 280 tpy for Continental Carbon Sunray, 656 tpy for Big Spring and Borger Carbon Black, and 133 tpy for Lehigh Cement Waco for a total of 1,069 tpy for these facilities. The total point source NO_X emissions modeled for Texas in 2023 and 2026 are 239,000 tons and 207,000 tpy, respectively and the total anthropogenic NO_X emissions modeled for Texas in 2023 and 2026 are 788,000 tpy and 711,00 tpy, respectively. Thus, even assuming the full amount of these claimed reductions of 1,069 tpy were not included in the modeling (and assuming they were not offset at all by any emissions that our emissions inventories may have missed) this difference in emissions level is not going to resolve the linkages from Texas to receptors in other states.

Regarding one commenter's statement that the EPA has not reflected the impact of recent consent decrees on two Oklahoma facilities, the EPA has reviewed the values in the modeling inventories for these sources. The commenter estimates that the impact of the 5/25/2018 consent decree on the Continental Carbon Black Production Facility[7] to be 530 tpy. The 2016 NO_X emissions were 842 tpy and 1,034 tpy in 2023 and 2026. This suggests the consent decrees may not have been reflected in the analytic years. The commenter estimates that the impact of the 9/28/2018 consent decree on the Anchor Glass Container Corporation Henryetta Facility[8] to be 494 tpy. The 2016 NO_X emissions were 195 tpy and 188 tpy in 2023 and 194 tpy in 2026, which are substantially smaller than the estimated impact of the consent decree asserted by commenter, making the maximum possible impact of the consent decree on the modeling 194 tpy. The total emissions reductions from the consent decrees in Oklahoma that may not have been reflected in the modeling are 530 tpy plus 194 tpy for a total of 724 tpy. The total point source NO_X emissions in Oklahoma included in the modeling of 2023 and 2026 were 80,000 and 72,000 tpy, respectively, and the total anthropogenic NO_X emissions modeled for Oklahoma in 2023 and 2026 are 200,000 tpy and 180,000 tpy, respectively. Thus, even assuming the full amount of these claimed reductions of 724 tpy were not included in the modeling (and assuming they were not offset at all by any emissions that our emissions inventories may have missed) this difference in emissions level is not going to resolve the linkages from Oklahoma to receptors in other states.

Regarding one commenter's statement that the EPA has not quantified Nevada facilities subject to enforcement related consent decrees for NO_X emissions reductions, the commenter tabulated names of these facilities and their estimated NO_X emissions reductions in Table5 of their comment letter. For each row of the table, the comment document provides footnotes with web links to the EPA's database, Enforcement and Compliance History Online (ECHO). However, with the exception of the Fernley Plant, the estimated NO_X emissions reductions for 14 of the 15 sources in the table are reported as "Unknown". To develop the 2023 non-EGU emissions in the 2016v3 platform, the EPA started with the 2019 NEI point source inventory, as it was the latest complete point source inventory at the time of the modeling. The 2026 emissions were derived from the 2023 emissions using industry-specific adjustment factors based on the AEO 2022 and reductions from any known additional controls implemented in the intervening years. The EPA was able to identify some of the sources in the commenter's table in the NEI, although four facilities could not be found in the NEI with NO_X, VOC, or PM emissions. The facilities that could not be found and the civil penalty from ECHO listed in parentheses were Caesars Entertainment Corp. ($9,125), Robertsons Ready Mix ($7,250 and $3,120), Nevada Ready Mix (case not found in ECHO), and EMD Acquisition LLC ($12,640). The penalties were modest with a maximum of $12,640. For the facilities that were found in the NEI, the actual annual NO_X emissions in tons from the 2016 inventory in the 2016v3 platform and the 2019 NEI point inventory plus the modeled emissions in the modeled 2016v3 2023 inventory were reviewed using information in facility and unit-level summaries of 2016v3 point source emissions provided in the docket for this action.

Following a review of the EPA inventories for the Nevada facilities referenced by the commenter, the only facilities that emitted more than 70 tons of NO_X emissions in 2019 are: Lhoist North America of Arizona – Apex Plant, Fernley Plant, and Pabco Building Products, LLC. In ECHO[9], the Lhoist case is marked as resolved as of 2/1/2017, with a civil penalty of $7,500. We presume that any resulting emissions reductions would have been implemented in time to be reflected in the 2019 NEI. The Pabco Building Products consent decree was from 2021, so any impacts would not be reflected in the 2019 NEI. The ECHO status for Pabco[10] is listed as resolved as of 6/8/2021 and the civil penalty was $7,600. Given the actual NO_X emissions in the 2019 NEI, the likely reduction in 2023 that could have been achieved even if all emissions were eliminated in 2023 (which is very unlikely unless the facility was shut down) is about 200 tons per year (tpy) of NO_X, while the total annual modeled anthropogenic NO_X in Nevada in 2023 is projected at 42,260 tons. Thus, even a reduction of 200 tpy would not be sufficient to resolve Nevada's contribution to other states.

The summary for the Fernley case in ECHO[11] is, "U.S. Environmental Protection Agency reached a settlement with the Nevada Cement Company to install new air pollution control technology at its Fernley, Nev. facility and replace a heavy-duty diesel truck and a diesel railcar mover at the facility with clean emissions vehicles to address alleged violations of federal CAA regulations. The pollution controls and clean emissions vehicles will reduce NOx emissions by approximately 1,140 tpy. Nevada Cement Company also paid a civil penalty of $550,000 as part of the settlement." The EPA located the consent decree in *United States* v. *Nevada Cement Company, Inc.*, Civil Action No. 17-302 (D. Nev.), which was amended in 2018. As amended, Section V.A of the consent decree requires installation and operation either of Selective Non-Catalytic Reduction (SNCR) or catalytic filter bags with ammonia injection and provides that the EPA may require installation of low NOx burners. A copy of these documents is available in the docket for this action.

A review of a June 19, 2020 issuance of two minor revisions to the operating permit for the Nevada Cement Company shows an allowance of discharge of NO_X to the atmosphere that will not exceed 475.84 pounds per hour, nor more than 2,084.20 tons per 12-month rolling period from the #1 Kiln, and an allowance of discharge of NO_X to the atmosphere that will not exceed

475.84 pounds per hour, nor more than 2,084.20 tons per 12-month rolling period from the #2 Kiln. The EPA contacted the Permitting Branch, Bureau of Air Pollution Control Nevada Division of Environmental Protection, Department of Conservation and Natural Resources seeking the status of installation and operation of SNCR at the Nevada Cement Company's Fernley Plant. The supervisor promptly responded that she has confirmed with the facility that the SNCR has been installed and is operational on the kilns prior to October 2022. A copy of this document is made available in docket for this action. We note that the actual 2019 emissions and the modeled 2023 emissions for this facility are about 1,800 tons, which is significantly less than the total of the modified operating permit level of 4,168 tpy total for the two kilns and is therefore a reasonable representation of the NO_X emissions from this facility for 2023. For 2026, Fernley plant was modeled with 959 tpy of NO_X, reflecting further reductions from 2023.

In summary, the commenter has not provided adequate information regarding alleged or potential NO_X decreases at Nevada facilities under enforcement settlements for the EPA to fully evaluate commenter's dispute of the modeled emissions for these sources and the identified linkages between Nevada and other states. According to the EPA's analysis, the civil penalties for the cases other than Fernley in the ECHO database were modest, indicating that the level of reductions would have been minimal. For Fernley, the modeled emissions are substantially less than the permitted emissions, so while the installation of the SNCR will reduce emissions once they are fully installed and operating, the EPA modeled the emissions in 2023 at only 43 percent of the modified level in the permit and therefore was at a reasonable level to support the contribution analysis.

Based on our detailed review of the consent decrees identified by commenters we conclude that we have sufficiently captured many of the claimed emissions reductions in the final rule emissions inventory, and for those that may not be reflected in the inventory, these relatively small emissions reductions in comparison to the magnitude of total anthropogenic emissions from these states allows us to conclude that including them would not have changed any linkages identified at Step 2.

[1] See *United States v. Cemex, Inc.*, No. 3:16cv471 (N.D. Tenn. 2016) and *https://echo.epa.gov/enforcement-case-report?activity_id=1400037538*

[2] See *United States v. Guardian Industries Corp.*, No. 2:15cv13426 (E.D. Mich. 2015). *See also* EPA's Civil Enforcement Report, *https://echo.epa.gov/enforcement-case-report?activity_id=3400258846*.

[3] See *United States v. Cemex, Inc*., No. 3:16cv471 (N.D. Tenn. 2016). See also EPA's Civil Enforcement Case Report, *https://echo.epa.gov/enforcement-case-report?activity_id=1400044172*.

[4] See *First Amendment to Consent Decree, United States v. Continental Carbon Co.,* No. 5:15cv290 (D. Okla. 2015) (imposing 50-ton emissions cap and requiring installation of SCR and low-NOx combustion burners). *See also* EPA's Civil Enforcement Report, *https://echo.epa.gov/enforcement-case-report?activity_id=18000809151*.

[5] *See* United States v. Sid Richardson Carbon, Ltd., No. 3:17cv1792 (D. La. 2017). *See also* EPA's Civil Enforcement Case Report, *https://echo.epa.gov/enforcement-case-report?activity_id=3000057207*

[6] *See* United States v. Lehigh Cement Co., No. 5:19cv5688 (E.D. Penn. 2019). *See also* EPA's Civil Enforcement Case Report, https://echo.epa.gov/enforcement-case-report?activity_id=3600663846.

[7] *See* First Amendment to Consent Decree, *United States v. Continental Carbon Co.*, No. 5:15cv290 (D. Okla. 2015) (imposing 50-ton emissions cap and requiring installation of SCR and low-NOx combustion burners). *See also* EPA's Civil Enforcement Report, https://echo.epa.gov/enforcement-case-report?activity_id=1800089151 (2,120,000 lbs/ yr NOx reductions across 2 facilities, with 1 in Oklahoma).

[8] *See United States v. Anchor Glass Container Corp.*, No. 3:18cv943 (M.D. Fla. 2018). *See also* EPA's Civil Enforcement Report, https://echo.epa.gov/enforcement-case-report?activity_id=3600749727.

[9] *https://echo.epa.gov/enforcement-case-report?activity_id=3601452966*

[10] *https://echo.epa.gov/enforcement-case-report?activity_id=3602495139*

[11] *https://echo.epa.gov/enforcement-case-report?activity_id=2600059825*

3.3.2.3 Non-triennial National Emissions Inventory (NEI) Year

Comments:

Commenters (0336, 0545) argue the 2019 inventory was not a National Emissions Inventory (NEI) year and therefore did not undergo the same level of scrutiny and review as an NEI year inventory would receive. Commenter (0547) states 2016 is not a NEI year, so the baseline emissions may not be complete for any source that isn't an acid rain source. The manner in which EPA developed the emissions inventory for these sources should be explained and any inconsistent methodology addressed.

Response:

The EPA disagrees that emissions inventory data used for the modeling and non-EGU analyses are not reliable. As explained in more detail in the Emissions Modeling TSD accompanying the Revised CSAPR Update, the 2016v1 emissions were developed over multiple years with input from MJOs, state and local agencies, and other parties as part of the 2016 Emissions Inventory Collaborative process. [46] As discussed in more detail in the 2016v2 and 2016v3 Emissions Modeling TSDs, with each successive version of the 2016 platform, more data were incorporated from the triennial 2017 NEI and the platforms emissions were improved using more robust methods, more recent data sources, and in response to feedback from stakeholders. As explained in the preamble in Section IV.C and in the 2016v3 Emissions Modeling TSD, the 2016v3 emissions platform used for this final action retains some data from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform. The 2016v1 platform, released in September 2019 was developed to be used by air quality management agencies and EPA to support modeling for regulatory purposes.

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[46] See the "Emissions Modeling Technical Support Document for the 2016v1 Emissions Modeling Platform" available in the Revised CSAPR Update docket as item EPA-HQ-OAR-2020-0272-0187.

The 2016v2 platform emissions used for the proposal modeling were released in September 2021 for comment and improved on the 2016v1 emissions by incorporating more data from 2017 NEI along with other updates that became available in calendar years 2020 and 2021 including data developed using updated models, methods, and source data sets. This is discussed in detail in the 2016v2 Emissions Modeling TSD. The 2016v3 platform used for this final action further improved on the 2016v2 emissions by incorporating responses to comments, corrections, and additional data that became available following the release of the 2016v2 platform. In this action, 2019 NEI point source emissions are used as the basis for the non-EGU analysis and as the starting point for quantifying the 2023 and 2026 non-EGU emissions used in the modeling.

Although neither 2016 nor 2019 are triennial NEI years during which a full NEI for all sources is developed, per the Air Emissions Reporting Rule (AERR), (80 FR 8787; February 19, 2015), Type A point sources large enough to meet or exceed specific emissions thresholds must be reported by state, local, and tribal agencies to the EPA every year. Smaller Type B point sources must only be reported to EPA every three years. The reported emissions go through a number of quality assurance checks prior to the NEI being finalized for a particular year. The resulting non-triennial point source inventories are appropriate for use in support of regulatory actions.

3.3.2.4 Claims of Non-EGU Data Input Incorrectly / Outdated Information Used

Comments:

Commenter (0411) believes that the modeling completed by the EPA did not appropriately account for existing emissions reductions in Minnesota and other modeling issues that would have demonstrated that Minnesota should not be included in the proposal. For example, in the approved Regional Haze Taconite FIP the plan identified 11,000 tons of NO_X emissions reductions from the taconite mines in Minnesota of which 4,500 tons of reductions would occur during the ozone season. These reductions were not included in EPA’s modeling under this proposal, thus overestimating ozone contribution from Minnesota. It is significant because between the reductions already identified by the EPA in its own Taconite FIP plus the reductions from approved Xcel Energy coal unit retirements occurring prior to 2030, Minnesota emissions reductions would meet or exceed the reductions needed to meet compliance with this proposed rule.

Commenter (0329) claims Minnesota is incorrectly included in this FIP proposal. Nitrogen oxides (NO_X) reductions from the Taconite FIP are not included. Full implementation of the Taconite FIP will result in reducing NO_X emissions from Minnesota by about 4,500 tons during the ozone season, while EPA estimates that the Plan would achieve total annual ozone season NO_X reductions of 2,334 tons (1,661 from EGUs and 673 tons from non-EGU sources). Because these reductions from the Taconite FIP are greater than that achieved by implementing the Plan, the MPCA believes that when modeling properly includes the Taconite FIP NO_X reductions, Minnesota will not be identified as contributing to downwind receptors. The commenter also believes that the EPA should have included NO_X reductions from the proposed heavy duty NO_X rule, voluntary reductions achieved through implementation of the

Volkswagen settlement and Diesel Emissions Reductions Act projects. Minnesota also encourages EPA to reconsider treating states that contribute to downwind nonattainment and states that interfere with downwind maintenance identically.

Commenters (0539, 0557) are concerned about EPA’s modeling treatment of the non-EGU NO_X reductions already planned to occur in Minnesota’s mining sector per the Taconite FIP. In their SIP Disapproval comment letter, the MPCA stated that about 11,000 tons of annual NO_X reductions (about 4,500 tons in ozone season) appeared to be missing from the EPA’s modeling for Minnesota. The commenter stresses this is a significant discrepancy, and its alleged omission must be resolved before the proposed FIP is finalized.

Based on the MPCA's April 15, 2022, response to the SIP disapproval by the EPA, MPCA believes that the modeling completed by the EPA did not appropriately account for existing emissions reductions in Minnesota and for other modeling issues that would have demonstrated that Minnesota should not be included in the proposal.

Commenter (0798) cites the EPA: “The future year non-EGU point inventories were grown from 2016 to the future years using factors based on the AEO 2021 . . .” But AEO 2021 does not appear to be an industry emissions inventory, but instead only appears to track energy consumption in various industries. It is not reasonable to use this approach when EPA had actual emissions inventories (such as the 2019 NEI) available, particularly for EAFs. Unlike EGUs, whose emissions might be expected to strongly correlate to energy consumption at the plant, EAFs NO_X emissions are not primarily driven by the combustion of fossil fuels. Thus, the EPA should compare actual updated emissions inventories with the AEO to demonstrate its accuracy and appropriateness as a basis for developing emissions inventories. The commenter adds Minntac is modeled to emit 3,900-4,167 tpy from 2032 to 2023. September 29, 2021, Emissions Data. Minntac has already committed, as reflected in its 2013 title V permit, to reduce emissions to 3,990 tpy as an annual cap on all facility NO_X emissions. Commenter (0798) continues, Keetac is projected to emit 4,631-4,949 tpy. According to the 2016 Barr Engineering analysis submitted to EPA, baseline calculations of Keetac data should not be based on recent emissions data because it is not representative of the mix of fuels the Keetac furnace is permitted to burn. Even so, a far more representative baseline is 3,455 tpy for uncontrolled NO_X emissions.

Response:

In response to statements by commenters that the EPA should consider the comments submitted on EPA’s 2016v2 emissions inventories in December 2021, the EPA acknowledges receipt of MPCA’s comments regarding updated emissions inventory data on point-source non-EGU sources in Minnesota, as well as data on point and non-point sources submitted in comments in the proposed action on Minnesota’s SIP submission. The EPA thanks MPCA for this information and has considered, and incorporated as appropriate, this information in the 2016v3 emissions inventories. The EPA also considered comments submitted by other commenters prior to the proposal.

Regarding the use of the AEO 2021 data to project emissions for non-EGU sources to the analytic years for the proposal modeling, the method used by the EPA for non-EGU projections varied by industry in both the proposal and final rule modeling. In the 2016v3 platform, for most non-EGU sources, the EPA removed emissions from units or facilities known to have closed and based the 2023 emissions for the remaining sources on the 2019 NEI. Those 2023 emissions were projected from 2023 to 2026 using industry-specific factors based on the AEO 2022 plus known closures and impacts from regulatory programs were factored in. For the Taconite-related sources mentioned by the commenters, the EPA incorporated draft year 2021 emissions into the 2023 inventory, as these were the latest available for those sources and they reflected a number of recently implemented control measures. In the spreadsheet on non-EGU control factors provided by the commenter, implementation dates for controls range from dates in 2018 through 2020 and would therefore be included in the 2021 emissions values used in the 2016v3 platform emissions. The EPA has confirmed that the final submitted year 2021 NOx emissions for these sources are equivalent to the draft 2021 emissions that were modeled for 2023. The 2026 emissions modeled for the taconite-related units are less than one half of 1 percent larger than the 2023 emissions.

These emissions estimates are reflective of the current status of efforts to implement best available retrofit technology (BART) FIP requirements for these sources. In particular, a revised emissions limit for the Minntac facility was finalized in March 2021 (86 FR 12095; March 2, 2021), and the emissions projections used for Minntac based on 2021 data are reflective of that limit. The EPA is still in the process of reconsidering and setting BART emissions limits for the remaining taconite facilities in Minnesota.[47] Using 2021 emissions data for these units provided the best emissions data available at the time the modeling was performed and until final BART emissions limits are set. As noted already, the EPA only considers emissions reductions from rules that are final. To the extent the commenters are referencing any emissions reductions from the second planning period of the Regional Haze Program, the EPA notes that it has not yet taken final action on the second planning period Regional Haze SIP submission from the MPCA.[48] Although the EPA acknowledges the efforts the state has made to develop a SIP submission, the EPA cannot incorporate non-final or uncertain emissions reductions into its transport modeling platform.

Comments:

Commenter (0549) reviewed the dataset and found several likely inaccuracies in EPA's Microsoft Excel file "*CSAPR 2016v2 emission summary_v2.xlsx*." Following this review, some ACC members were able to survey their facilities and found that the annual NO_X emissions in

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[47] Petitions for review and petitions for reconsideration of EPA's 2016 BART FIP, 81 FR 21672 (Apr. 12, 2016), remain pending and settlement discussions with the taconite facilities are ongoing. *See* Petition for Judicial Review, *U.S. Steel Corp. v. U.S. EPA*, No. 18-1249 (8th Cir. Feb. 2, 2018).

[48] 87 FR 52856, August 30, 2022. Minnesota was one of 15 states named in a Finding of Failure to Submit a SIP which satisfies the visibility protection requirements of the Clean Air Act (CAA), as described in implementing regulations, for the regional haze second planning period. Minnesota submitted a second planning period Regional Haze SIP submission to the EPA on December 22, 2022.

EPA's data were substantially over-estimated. For several facility sites, EPA's emissions data is an overstatement of the sites' actual emissions by up to 18 times. Upon discovering this inaccuracy, commenter (0549) found that the EPA based its emissions information on sources beyond boilers. For example, one ACC member found that a site with no boilers was listed as having about 900 tpy NO_X emissions from EPA's raw emissions data tab. This information further informed EPA's receptor modeling, which informed EPA's emissions control decisions in the proposal. Logically, if EPA based proposed requirements that address boilers in part on NO_X emissions modeling that does not include boilers, it risks an inaccurate or inconsistent regulatory result.

Response:

EPA has reviewed the docket and cannot locate the referenced file "CSAPR 2016v2 emission summary_v2.xlsx" or another file with a similar name. As a result, we cannot provide a detailed response to this comment. It also appears that the commenter may be confusing the datasets used to build emissions inventories for purposes of air quality modeling at Steps 1 and 2 of the framework, with the separate process of analyzing potential non-EGU industry emissions reductions at Step 3. See Section 2.2 of this document for further discussion of the latter.

Comments:

Commenter (0517) requests that the EPA use 2017 NEI data for all non-EGU point sources as well as for the oil and gas sector point sources. They argue the NEI data are more representative of actual facility emissions.

Commenter (0549) believes there have been significant changes in sites' emissions sources since 2016, including other federal and state restrictions on NO_X emissions and industrial source NO_X emissions reductions. Updated actual emissions data are available for non-EGU sources (*e.g.*, data from sources subject to monitoring and reporting under 40 CFR part 75) and should be compiled and used for this type of sweeping rulemaking rather than projections of data from almost a decade ago that also do not involve the sources subject to the proposed requirements.

Commenter (0782) states that the EPA's model fails to account for substantial NO_X and VOC reductions in Colorado and Wyoming since 2016. For instance, the EPA takes baseline emissions and "future year inventory" estimates from the Western Regional Air Partnership (WRAP) from 2019 and March 2020 respectively for its estimate of future NO_X and VOC emissions from oil and gas sources in Colorado. Neither the WRAP 2019 baseline inventory nor the March 2020 "future year inventory" adequately account for the substantial number of regulatory measures taken by Colorado to reduce NO_X emissions from oil and gas and from other non-EGU sources in the relevant time period.

Commenter (0782) states Wyoming Department of Environmental Quality (WDEQ) noted some of the regulatory actions Colorado was taking with respect to oil and gas sources in its good neighbor SIP. The EPA wholly ignores these regulatory actions and many others taken since Wyoming submitted its good neighbor SIP in January 2019.

Commenter (0782) notes other non-EGU NO_X emissions reduction measures, which would undoubtedly influence the EPA's modeling, include a substantial number of state rulemakings and new regulations in Colorado and the conversion of the Holly Frontier Oil Refinery to renewable fuels along the border of Wyoming and Colorado, a 924-ton reduction in annual NO_X emissions. It is imperative that the EPA's model adequately account for all local measures to reduce NO_X and VOC emissions.

Response:

Regarding the use of 2017 NEI data for non-EGU point sources and oil and gas point sources, in the 2016v3 platform emissions used for the final rule modeling, for 2016 the EPA used 2017 NEI data to represent year 2016 emissions for many states, except where data specific to the year 2016 were submitted by states and in states covered by the WRAP oil and gas inventory. The commenter was unclear on whether they were also suggesting the use of 2017 NEI for the analytic year emissions. For non-EGU emissions in the 2016v3 platform, the EPA primarily used year 2019 emissions as the 2023 emissions and projected those to 2026 using methods appropriate to the industrial categories. See the 2016v3 Emissions Modeling TSD for more details.

Regarding the use of 40 CFR part 75 data in analytic year modeling, the EPA does not use these data directly to prepare inventories, but the Air Emissions Reporting Rule (AERR) requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA every year. State, local, and tribal air agencies may choose to make use of the 40 CFR part 75 data when they compute their emissions for each NEI year.

When preparing emissions inventories for analytic years, the EPA reflects known and enforceable "on the books" national and local rules, control programs, facility and unit closures, consent decrees, and settlements with specific quantifiable impacts. Federal regulations are reflected, but there are some situations in which state and local rules may not be known to EPA or the impacts cannot be quantified. The approach used to develop analytic year emissions for non-EGU sources in the 2016v3 platform for the final rule modeling is described in detail in the 2016v3 Emissions Modeling TSD. In summary, the 2019 NEI point source data were used as the starting point for the 2023 non-EGU point source emissions. Sources known to be closed were then removed. The remaining sources were projected using industry-specific factors computed based on Annual Energy Outlook (AEO)[49] 2022, then applicable control programs were applied. The resulting emissions for the Holly Frontier Navajo Refining Artesia refinery following this process were 226 tons of NO_X in 2023 and 223 tons in 2026, plus 525 tons of VOC in 2023 and 526 tons in 2026.

In response to comments claiming that the EPA is ignoring impactful state control programs in Colorado, the EPA notes that the Colorado Department of Public Health and the Environment submitted comments on the 2016v2 platform prior to development of the 2016v3 emissions and did not provide information about recent rules that should be reflected in the analytic year inventories. The Colorado Department of Public Health and the Environment did request that the year 2016 emissions developed as part of the 2016v1 platform be used because they

[49] https://www.eia.gov/outlooks/aeo/

incorporated the impact of their green completion rules for oil and gas sources. The EPA used the WRAP future year inventory for 2023 and 2026 as had been done in the 2016v2 platform. No details were provided by comments on this rule to support the quantification of the impacts of unidentified recent rules in Colorado for inclusion in the 2016v3 inventories for the relevant analytic years for this action.

3.3.2.5 Claims of Incorrectly Assumed Non-EGU Retirements and Idled Plants

Comments:

Commenter (0340) notes, in projecting emissions for non-EGU sources in the 2016v2 modeling platform, the EPA included facilities that were not operating. The EPA used 2019 emissions where available, but also used previous years' emissions information when necessary and projected those emissions to future years. "A draft set of projected 'ptnonipm' emissions were reviewed and compared to recent emissions data from 2017 through 2019. In cases where the recent and projected emissions were substantially different, the 2023 emissions were instead taken from a recent year of emissions and were then projected from 2023 to later future years." Specifically, the EPA identifies a Kentucky source, "AK Steel Corp," and the use of 2018 emissions projected to future years in the modeling platform 2016v2. In fact, this facility has not operated since 2019.

Commenter (0798) argues although these enforceable closures are not scheduled to occur prior to the EPA's proposed 2026 deadline for non-EGUs to comply with the proposed rule, which is not a reasonable excuse for failing to take them into account, at least with respect to Arkansas. The EPA's selection of a compliance deadline of 2026 is based on deadlines applicable to downwind nonattainment regions, and thus it is not necessary or reasonable to require the same deadline where only attaining maintenance receptors are affected, as is the case with Arkansas which is linked solely to the Brazoria County, Texas receptor, is predicted to be in attainment (but still maintenance) by 2023, to improve even further by 2026, and be full attainment (*i.e.*, no longer maintenance) by or before 2032.

Response:

The EPA accepted the comment on the AK Steel Corp. source being retired before 2023 and has removed emissions from this facility from the 2023 and 2026 emissions inventories used in the final rule modeling.

In the 2016v3 modeling, Arkansas is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and five maintenance-only receptors. It is also linked to seven violating-monitor maintenance-only receptors. Comments asserting that the EPA should allow for longer compliance timeframes for upwind states that are linked only to areas that may struggle to the maintain the NAAQS do not explain how doing so would satisfy the requirement to meet obligations in the first instance "as expeditiously as practicable" but no later than the next applicable attainment date. The D.C. Circuit has held on five different occasions that the timing framework for addressing interstate transport obligations, which includes both prong 1 *and* prong 2 of CAA section 110(a)(2)(D)(i)(I), must be consistent with the downwind areas' attainment schedule. In particular, for the ozone NAAQS, the states and the EPA are to address interstate transport obligations "as expeditiously as practicable" and no later than the attainment schedule set in accordance with CAA section 181(a). *See North Carolina*, 531 F.3d 896 at 911–13 (D.C. Cir. 2008); *Wisconsin*, 938 F.3d 303 at 313–20 (D.C. Cir. 2019); *Maryland*, 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, 6–7 (D.C. Cir. 2019). The EPA's approach to "interference with maintenance" and selection of analytic years are discussed in Sections III.B and IV.A of the preamble, respectively, as well as in Section 3.1 (Years Selected for Analysis). Further considerations regarding the timing and compliance schedule of this action are addressed in the Executive Summary of the preamble and in Section VI.A of the preamble.

3.3.3 Onroad Mobile Sources

Comments:

Commenter (0323) cites the Alpine Geophysics, LLC report that merged the onroad emissions data with a 2028 "base case" modeling simulation. This work assesses how the change in mobile source emissions between the 2028 base case and the Cleaner Trucks Initiative (CTI) scenario would change the ozone and $PM_{2.5}$ ambient air quality projections at receptors in the continental United States. The modeled 2028 base year 8-hr ozone DVs were found to be above the 70 ppb NAAQS in the states of California, Utah, Colorado, Texas and Connecticut. Applying the 90 percent NO_X emissions reduction CTI scenario to the 2028 base year eliminates ozone nonattainment everywhere east of the Rockies and in Denver and leaves only the states of California and Utah with 70 ppb 2015 ozone NAAQS nonattainment areas. Multiple monitors in California and in Salt Lake County, Utah also show modeled attainment with the CTI strategy. The greatest ozone impact of the strategy is seen in urban areas and along highway corridors with reductions of up to 6.5 ppb seen in the west (San Bernardino) and 4.9 ppb seen in the east (Atlanta). The commenter provides details on the CTI strategy impacts on the annual $PM_{2.5}$ DV nationwide with modeled attainment changes occurring at monitors in Madera, San Joaquin, and Stanislaus counties in California. The greatest annual $PM_{2.5}$ impacts are reductions of 0.64 $\mu g/m^3$ (4.1 percent) seen in the west (Kern County, CA) and 0.21 $\mu g/m^3$ (2.3 percent) reduction in the east (Chicago). As with the annual $PM_{2.5}$ modeling, areas shown to move to modeled attainment as a result of the CTI strategy include Madera, Merced, and San Joaquin counties in California. The greatest daily $PM_{2.5}$ impacts are reductions of 4.5 $\mu g/m^3$ (9.8 percent) seen in the west (Tulare County, CA) and 0.9 $\mu g/m^3$ (4.5 percent) reduction in the east (Chicago).

Commenter (0359) cites the Connecticut Department of Energy and Environmental Protection providing comment to the Advanced Notice of Proposed Rulemaking for the Control of Air Pollution from New Motor Vehicles: Heavy Duty Engine Standards on February 19, 2020, acknowledged the magnitude of the vehicular contribution by stating: "Connecticut air quality monitors record some of the highest ozone levels in the eastern United States, especially along heavily trafficked transportation corridors where criteria air pollutant emissions are most densely concentrated. In 2019 Connecticut monitored twenty-one days when air quality in the state exceeded the 2015 ozone NAAQS. Mobile sources account for sixty-seven percent of

NO_X emissions in Connecticut."

Response:

The EPA finalized a regulation addressing the Control of Air Pollution From New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards (88 FR 4296; January 24, 2023)[50] which sets engine and vehicle standards for heavy duty vehicles beginning with model year 2027 vehicles. The resulting emissions reductions will phase in gradually and not before calendar year 2027 and therefore are not included in the calendar year 2026 emissions used for the 2016v3 modeling. Commenter 0323 performed air quality modeling using a year 2028 emissions inventory from the 2016v1 platform merged with the potential emissions benefits from the Heavy Duty 2027 rule that would not result until after the year 2035, and then argues that additional controls should be placed on mobile sources instead of requiring controls to stationary sources. Their computed improvements in ozone and PM air quality at various monitors resulting from the Heavy Duty 2027 rule—which we do not necessarily concede are an accurate reflection of emissions reductions under this or other final mobile source rules—would not occur until well past the Serious Area attainment date of 2027. Thus, any such changes would not affect the outcome of our conclusions at Steps 1, 2, or 3 in the analysis for this rule.

See Section V.B.4 of the preamble regarding from the consideration of mobile sources at Step 3.

3.3.4 Nonroad Mobile Sources (Other Than Marine Vessels)

3.3.4.1 Uinta Basin Railway and Emissions Impacts from Increased Production

Comments:

Commenter (0758) states the emissions inventory, and thus the modeling, ignores an important aspect of the problem, increased emissions from the Uinta Basin Railway. Recently, the U.S. Surface Transportation Board approved construction and operation of the Uinta Basin Railway, a planned 88-mile-long railway that would transport crude oil from Myton and Leland Bench, Utah to Kyune, Utah, where it would connect to the national rail network. Thus, as this is a final action by the federal government itself, the EPA cannot justify ignoring it based on a claim that the EPA does not consider future actions which are not final actions. The commenter explains, the oil railway is intended to quadruple oil production in the Uinta Basin from roughly 90,000 barrels per day to 350,000 barrels per day, by providing a cheaper means of transporting crude oil to the Gulf Coast. Uinta Basin oil producers currently lack a cost-effective means of transporting oil outside the Basin, so they are mostly limited to trucking their oil to Salt Lake refineries (which cannot accept more than 80,000-90,000 barrels per day) and are thus forced to sell to Salt Lake refineries at a discount, compared to the West Texas

[50] See *https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-and-related-materials-control-air-pollution*.

Intermediate price benchmark. According to the project's proponents, the rail would open oil producers' access to new markets, allowing them to raise their prices, which would spur increased oil drilling and production. According to the EIS for the oil railway, the intended quadrupling of oil production in the Basin would require up to 3,330 new wells to be drilled in the Uinta Basin over the next 15 years; increased trucking to transport oil from oil fields to the rail terminal and to construct and maintain new wells, resulting in 46,051,432 vehicle miles traveled per year; and 11 unit trains per day traveling in and out of the Uinta Basin and through Colorado, each consisting of 110 tanker cars each and nearly 2 miles long.

Commenter (0758) cites the EIS, estimating this amount of drilling would result in the following annual emissions (tpy) associated with oil and gas development, including trucking: CO- 4,454, NO_X- 3,146, VOCs- 5,558. These figures, however, are likely a gross underestimate, because they assume the application of operator-committed measures that do not apply generally to all wells in the Uinta Basin. Further, they do not consider VOC emissions from wastewater pits. Recently, Utah, the EPA, and the Ute Indian Tribe updated the 2017 Uinta Basin Emissions Inventory as catalogued in a paper published in November 2020 ("VOC Inventory Study"). This effort made the inventory more accurate and found that the previous inventory significantly underestimated VOC emissions from produced water disposal. Indeed, the VOC Inventory Study found that the 2017 inventory underestimates VOC emissions from produced water disposal facilities by 69,137 tpy. In any event, increased emissions spurred by the oil railway will significantly contribute to ozone levels in Utah, Colorado and downwind states.

Commenter (0758) adds, the EIS estimates the following annual emissions (tpy) associated with rail operations along the 88-mile-long rail line, excluding downline emissions in Utah and Colorado: CO-405, NO_X-1,056, VOCs-40. Total NO_X and VOC emissions along the downline segments (excluding emissions in attainment areas where train operations would not exceed 8 trains per day) would total 5,771.06 tpy and 205.33 tpy respectively, and CO emissions along the same segments would total 2,076.41 tons per year. The EPA must revise its analysis to consider these increased emissions caused by the United States government's final approval of the Uinta Basin Railway.

Response:

The commenters state that the emissions inventory, and thus the modeling, does not reflect increased emissions that would result from the construction of the Uinta Basin Railway and the increased production expected to occur once the railway is in place. The Environmental Impact Statement[51] commenter cites estimates the following annual emissions (tpy) associated with rail operations along the 88-mile long rail line: Carbon monoxide 405, Nitrogen oxides 1,056, and VOCs 40; and segments of that railway would go through the Denver nonattainment area.

The timeline for the rail construction and the additional drilling that would result is unclear. Although the Federal Surface Transportation Board issued a final Environmental Impact Statement, there is a pending petition for review in the D.C. Circuit brought by Center for

[51] *http://www.uintabasinrailwayeis.com/*

Biological Diversity and other petitioners that could impact the project.[52] Additional pending issues include nonattainment area constraints, geographical planning, and funding uncertainties. There is also a high degree of uncertainty that remain regarding the timing of the railroad's construction and the timing, location, and magnitude of any subsequent increase in exploration, drilling, or downline impacts, making it not possible nor appropriate to reflect additional emissions resulting from the Uinta Basin Railway, either directly or indirectly, in the emissions inventories used for this action. For purposes of this action, we note that any increase in emissions in Utah resulting from this railway project would only serve to confirm or reinforce that emissions from Utah are linked to out of state receptors. And the potential increases in emissions in either Utah or Colorado would likely tend to confirm or reinforce the existence of nonattainment and/or maintenance receptors in Colorado. However, due to the many uncertainties in future emissions, and thus future air quality impacts, associated with this project, the EPA disagrees with commenters' assertion that it must revise its analysis to consider these emissions in its modeling analysis in this action.

3.3.5 Other Emissions Topics

3.3.5.1 Emissions at Airports need to be Adjusted

Comments:

Commenter (0505) asserts the future year NO_X emissions from airports in Texas ozone nonattainment areas, Houston Galveston-Brazoria (HGB), Dallas-Fort Worth (DFW), and San Antonio, are overestimated in the EPA's 2016v2 modeling platform. The commenter mentions that they contracted the Texas Transportation Institute (TTI) to develop future year emissions inventories for 2023 and 2026 among other years using the latest available information. This comparison shows significant overestimation in NO_X emissions ranging from 25 percent to 43 percent. This overestimation could lead to inaccurate modeled contributions and lead to overcontrol to offset nonexistent emissions. The EPA should update the emissions in its modeling platform to the TTI emissions inventories and reevaluate its proposed FIP and the proposed Texas transport SIP disapproval in light of the update.

Response:

The EPA reviewed the inventories used for airports in Texas for the base and analytic years in the 2016v2 platform. The EPA found that there was some double counting in the year 2016 inventory between data developed by the EPA and state-submitted data for some Texas airports, and this was corrected in the final rule emissions inventory; emissions were correspondingly reduced. The EPA reviewed the TTI projected emissions inventories as compared to publicly released passenger and freight activity at major Texas airports and found that the TTI inventories did not take pandemic impacts into account and therefore disagrees

[52] *Center for Biological Diversity, et al. v. U.S. Forest Service, et al.*, No. 22-1237 (D.C. Circuit) filed September 8, 2022.

that the TTI inventories provide a better source of data for the analytic years. The EPA developed the final rule emissions for airports nationwide by computing projection factors based on the Terminal Area Forecast (TAF) 2021[53] (released in June 2022) and applying those to the base year airport emissions. The TAF 2021 accounted for pandemic impacts and supported the derivation of airport-specific adjustment factors for larger airports. To project emissions at smaller airports, the EPA derived projection factors based on state-level changes in traffic and applied those to the base year emissions. Additional information on the projection of emissions at airports are provided in the 2016v3 Emissions Modeling TSD and the resulting impact on emissions by airport is quantified in the point source summaries in the docket for this action.

3.3.5.2 The EPA Must Actively Engage Commenters to Review Potential Additional Emission Inventory Development and Modeling

Comments:

Commenters (0279, 0301, 0303, 0307, 0323, 0331, 0340, 0350, 0372, 0394, 0397, 0411, 0431, 0436, 0500, 0508, 0518, 0531, 0539, 0549, 0557, 0798) are concerned that the EPA is not providing assurances of a reasonable opportunity for actively engaged commenters to review potential additional emissions inventory development and modeling. The commenters request that the EPA incorporate all appropriate comments as submitted by state and stakeholder entities into updated modeling platforms and that projection year inventories and associated photochemical air quality modeling be conducted to revise both base case and control case assumptions. It is further requested that the EPA make these platforms, projections, and modeling results available for comment well before a proposed final FIP is published.

Commenters (0266, 0323, 0331) state in December 2021 in response to EPA requests for inventory review and updates, Minnesota and other stakeholders submitted detailed comments on the 2016v2 emissions inventory platform to correct errors that existed in that platform. Many of these revision requests have impact on the proposed rule’s projection year inventories and base case control assumptions for multiple sources and source categories. However, review of the proposed rule’s modeling platforms confirms that most of these comments have not been incorporated into the proposed rule’s base case air quality and associated analyses. The EPA’s declared efforts to revise the emissions inventory platform raises the question about whether EPA intends to update the modeling that has been used as the basis for the SIP disapprovals and the proposed FIP - but only in support of the final rule.

Commenters (0323, 0331) continue, while EPA is urged to rely on modeling that accurately reflects current on-the-books regulatory requirements and up-to-date emissions inventories, there is strong opposition to the possibility that the EPA would conduct any such additional modeling to support a final rule and not provide the opportunity for those data to be reviewed, analyzed, commented, and having those comments addressed by the EPA in advance of any

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

final proposed FIP. These concerns were also expressed earlier, in July 2021, by several Multi-Jurisdictional Organizations (WESTAR, LADCO, Southeastern States Air Resource Managers, Mid-Atlantic Regional Air Management Association, and Central States Air Resource Agencies Association).

Commenters (0324, 0332, 0336, 0359, 0436, 0513) state they are concerned that any final modeling performed for this rule will use the version 3 data set without the opportunity for states to review the changes being made. While EPA staff have indicated that the version 3 changes may not be significant, they have also discussed updates to the commercial marine emissions inventories, where emissions of NO_X may be reassigned from one area to another. Commenter (0336) states such changes could be impactful for certain states such as Virginia.

Response:

The EPA disagrees that it has not provided ample opportunity for stakeholders to review and comment on the inventories used for modeling. We acknowledge that comments submitted in December 2021 were not reflected in the emissions inventories released with the proposal in the spring of 2022. However, the EPA has incorporated updates as appropriate into its 2016v3 modeling platform based on both pre-proposal feedback and information provided in public comments on the 2016v2 platform.

The 2016v2 emissions modeling files were made available for comment starting September 2021.[54] By providing the modeling platform on September 21, 2021, and requesting that comments be provided to EPA's emissions modeling group by December 17, 2021, and also through comment on the FIP and SIP action proposals throughout 2022, the EPA gave stakeholders and interested parties sufficient opportunity to review and comment on the data used in the 2016v2 modeling analyses.

The EPA incorporated public comments received on proposals related to 2015 ozone NAAQS interstate transport to update its emissions inventories and other model inputs. The final rule modeling using the 2016v3 platform was performed using updated emissions projections, such as additional emissions reductions for EGUs that reflect the emissions reductions following promulgation of the Revised CSAPR Update for the 2008 ozone NAAQS, more recent information on plant closures and fuel switches, and updates to projected emissions for other sectors. The construct of the updated emissions platform is described in the 2016v3 Emissions Modeling TSD contained in the docket of this rulemaking. The EPA did not release the 2016v3 emissions inventories used for the final rule modeling before the modeling occurred, nor is it standard practice to do so.

3.3.5.3 Step 3 Baseline Emissions Differs from Steps 1 and 2

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

Comments:

Commenters (0396, 0517, 0554) state the 2023 and 2026 EGU NO_X emissions data that the EPA used in Steps 1 and 2 of its analysis to determine the nonattainment and maintenance receptors impacted by upwind states' contributions is different from the emissions data that the EPA used in Step 3 of its analysis where it made control determinations. Specifically, the EPA relied on its 2016v2 modeling platform for Step 1 and 2, whereas EPA conducted an "Engineering Analysis" using its IPM to redefine the 2023 and 2026 EGU NO_X emissions for Step 3.

Commenter (0396) believes many assumptions underlying EPA's analysis are suspect. As a result, there appears to be a substantial disconnect between the assumptions EPA used to identify covered states and the control determinations the EPA proposes for those states. Specifically, the EPA appears to have mischaracterized several Cleco units, including the Coughlin, Teche, and Acadia Power Stations. The NEEDS database EPA used to determine NO_X emissions in Steps 1 and 2 indicates that the capacities of Coughlin and Acadia are 729 and 1,087 MW, respectively, but the "Engineering Analytics" EPA used in Step 3 assumes those units have capacities of just 481 and 777 MW. The NEEDS database also appears to be missing Teche Unit 3 entirely, even though the EPA's "Engineering Analytics" lists Teche 3 as an oil/gas steam EGU that must reduce its emissions significantly per the EPA's assumption that SCR would be cost-effective. The EPA's IPM model also assumes that Big Cajun II Unit 3 will retire before the 2023 ozone season, and thus assumes no emissions from the unit, whereas the EPA's "Engineering Analytics" assumes that unit will emit 673 tons of NO_X in the 2023 ozone season. These inconsistencies resulted in overly optimistic control determinations and underestimated state allowance budgets. A corrected and consistent analysis is likely to confirm that the Proposal will overcontrol Louisiana.

Commenter (0554) specifies the differences are substantial, especially for BHE units. For 2026, the EPA's Step 3 analysis assumed approximately 16 percent greater emissions for both Wyoming and Utah than the EPA assumed in its Step 1 and 2 analyses. The differences for 2023 EGU NO_X emissions from PacifiCorp EGUs are even greater. In Utah, the Engineering Analysis EPA used in Step 3 for PacifiCorp EGU NO_X emissions is 143 percent greater than the 2016v2 emissions that the EPA used in Steps 1 and 2. In Wyoming, the difference is 293 percent. These differences represent a significant disconnect within EPA's 4-step interstate transport framework policy that the EPA has not explained.

Response:

See Section IV.C.2.a of the preamble for a response to the comments on the emissions inventories used for Steps 1 and 2 versus those used for Step 3.

3.4 Nonattainment and Maintenance Receptor Identification Modeling

3.4.1 Approach for Identifying Nonattainment Receptors

Comment:

Commenter (0344) states that the data used in EPA's modeling is incomplete and erroneous and believes that the impacts from the proposed rule as written won't be as significant or as cost-effective as EPA projects. The commenter believes it is problematic because Indiana must rely on the federal rule to fulfill its good neighbor obligations. However, the current rule is insufficient to stand on its own, and it fails to adequately address problem receptors.

Response:

The EPA disagrees with the commenter's claim that the EPA's modeling is incomplete and erroneous. As described in the preamble Section III.B and in the Air Quality Modeling Final Rule TSD, the EPA used the state-of-the-science CAMx model which is one of two photochemical models recommended for regulatory applications in Appendix W of the EPA's modeling guideline.[55] This comment may be in relation to the separate non-EGU screening assessment the EPA conducted at Step 3. See Section V of the preamble and Section 2.2 of this document for response to comments on those topics.

3.4.2 Approach for Identifying Maintenance Receptors

Comment:

Commenter (0763) references TCEQ who argues that 2012, rather than 2011, should be used as the base year in determining "'Good Neighbor' modeling". TCEQ contends that using outlier year data to project future NO_X levels is imprecise. In particular, 2011 was a meteorologically anomalous year for Texas as it was the hottest year on record, as well as the single-worst drought year recorded in Texas. The years 2017, 2020, and 2021 also reached record levels as the hottest years on record, and coincidently 80 percent of the state is in severe drought conditions currently. TCEQ used 2012 in their own regional photochemical modeling, arguing that this method is more reliable as it accounts for both emissions reductions and because of the shorter interval between the monitored DV and the projected DV. The use of the most recent DV out of a set of three for those downwind receptors marked as maintenance, irrespective of if they were the highest or lowest reading. TCEQ argue that this allows for consideration of emissions reductions that have occurred. TCEQ effectively has proffered alterations to the accepted framework, arbitrarily redefined the base year parameters, and selectively chosen DV and in doing so produced modeling that is ill suited to protecting nonattainment and maintenance neighbors and incorrectly concludes it is not a significant contributor to ozone pollution under the 2015 NAAQS standards.

Response:

Issues associated with TCEQ's modeling are addressed in the SIP disapproval action (88 FR 9336) and are not within scope of this action.

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[55] *Guideline on Air Quality Models* ("Appendix W" to 40 CFR part 51), section 5.3.1, page 5213

3.4.3 Method for Projecting Future Year Design Values (DVs)

Comment:

Commenter (0758) states relying largely on a 5-year average is problematic because this approach smooths the data on a metric that is already adjusted for interannual variability (*e.g.*, the DV is already a 3-year average), thus under-projecting the actual incidence of DVs above the standard.

Response:

The EPA disagrees with this comment. The EPA followed the approach recommended in its guidance for attainment demonstration modeling for determining the base period DVs to use in projecting future year DVs based on the relative change in ozone concentrations between the base year modeling and the future year modeling. Specifically, the guidance recommends using the "average of the three DV periods, which in the base emissions inventory year. This average is expected to best represent the air quality resulting from base year emissions with consideration of meteorological and emissions variability." The EPA notes that in Step 1 of the 4-step interstate transport framework, that in addition to projecting the 5-year average DV, the EPA also projects the base period maximum DV. The maximum DV is expected to account for the effects inter-annual meteorological variability and, in this respect, the projected maximum DV is used to estimate future air quality under ozone-conducive meteorology.

Comment:

Commenter (0547) says that in this proposed rulemaking EPA considers an alternative "no water" approach, in which EPA eliminated from the RRF calculations the modeling data in the grid cells that are dominated by water (*i.e.*, more than 50 percent of the grid cell is water) and that do not contain a monitoring site. This alternative approach was also used in the CSAPR Update. Air Quality Modeling Proposed Rule TSD. As a result of this alternative approach, those cells that are greater than 50 percent water are treated as being 100 percent overwater—even if part of the grid cell also includes land and land- based emissions—as the "meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water." 87 Fed. Reg. 20,067. Ultimately, for the proposed rule, the EPA relied on the "no water" approach for identifying nonattainment and maintenance receptors, and such approach culminated in a different designation of at least two receptors. Commenter (0547) specifies under the "no water" approach the Cook County, Illinois receptor 170317002 has a projected average DV of 70.1 ppb, whereas under the 3 x 3 approach it has a projected average DV of 71.1 ppb. As a result, its final designation in this proposed rulemaking is maintenance-only receptor (based on a 73 ppb projected maximum DV) as opposed to a nonattainment receptor. 87 Fed. Reg. at 20068, n. 120. Likewise, the Lake County, Illinois receptor 170971007 has a final designation as neither a non- attainment nor a maintenance-only receptor under the "no water" approach, whereas under the 3 x 3 approach it would be a maintenance-only receptor with a maximum average DV of 69.9 ppb. Id.

Response:

As described in the preamble Section IV.E and in the Air Quality Modeling Final Rule TSD, the EPA calculates projected DVs based upon two approaches, the "3 x 3" approach and the "no water" approach. In both approaches, the EPA uses the base year (*i.e.*, 2016) and future year (*e.g.*, 2023) modeled ozone concentrations to calculate Relative Response Factors (RRFs) which represent the relative change in ozone concentrations between the base year and the future year for each monitoring site. The RRFs are then applied to base period measured average and maximum DVs to project DVs for the future year. The RRFs are based on the ratio of average ozone concentrations in the future year to the corresponding average concentrations in the base year. The base year and future year average concentrations are calculated using model data for the ten days with the highest modeled ozone concentrations in the base year. In the "3 x 3" approach, the top 10 ozone concentration days are identified based on the maximum model predicted concentration in the "3 x 3" array of grid cells surrounding and including the grid cell containing the monitoring site. In contrast, in the "no water" approach, model predictions from grid cells that have 50 percent or more of their area as water, and do not contain the monitoring site, are excluded from the calculations. The commenter notes that the "3 x 3" and "no water" approaches can result in slightly different projected DVs at monitoring sites nearly coastal areas. In the instance cited by the commenter, in the proposal modeling monitoring site 170317002 was identified as a nonattainment receptor using the "3 x 3" approach, but in the "no water" approach this monitor was identified as a maintenance-only receptor. Thus, this monitor is a receptor using either approach. As described in Section III.B. of the preamble, the EPA applies the multifactor assessment at Step 3 of the 4-step interstate transport framework to a linked state regardless of whether the state's linkage is to a maintenance-only receptor or a nonattainment receptor. Regarding monitoring site 170971007 in Lake County, Illinois, including this monitor as a receptor would not have affected which states are covered by the proposed rule. That is, upwind states that contributed at or above the 1 percent of the NAAQS threshold to this Lake County monitoring site were also linked to one or more receptors that were identified using the "no water" approach based on the proposal modeling.

3.4.3.1 Alleged Failure to Account for Exceptional or Atypical Events in Calculations and Models

Comments:

Commenters (0436, 0509, 0547, 0782) state consideration of atypical or exceptional events such as wildfire can have a significant influence on a monitor's DV. The EPA noted that it was holding the 2016 wildfire data "constant" in future years, despite significant increases in wildfires over the last five years. Wildfires and other "atypical" events have only increased in the last ten years. Indeed, seven of the ten largest wildfires in Colorado history have occurred in the last ten years, and the top three occurred in 2020. Commenters argue assuming that (1) wildfire events would remain constant at 2016 levels or (2) failing to account for the impact of these events on baseline and future DVs suggests EPA's model needs adjustments. While commenter (0782) cannot confirm how removal of atypical event influenced data would affect

EPA's conclusions (particularly since the commenter did not have timely access to the model), it is likely that the EPA' s consideration of such atypical events in its model would have a significant impact on the baseline DV and future DVs of all monitors in Colorado and could affect EPA's conclusions regarding Wyoming and BHE's impacts on the Douglas County monitor's attainment.

Commenter (0547) details the increasing frequency and destruction of wildfires. From 2014-2018—the years in which the average and maximum DVs of this rulemaking are based—a significant number of wildfires occurred, and the average wildfire size increased during this period. These wildfires likely had an impact on ozone levels in Colorado during this period, and the 2014-2018 DVs. Nationally, according to National Interagency Fire Center, 8.4 million acres have burned so far this year, which is 47 percent higher than the 10-year average to this date. Montana, which accounts for 1.2 million of those blackened acres, has been a focal point for seemingly endless fires producing staggering quantities of smoke. Combined with the smoke created by other fires in Idaho, Oregon, Washington, and northern California, the fouled air has affected residents across large sections of the country. In addition, the likelihood of wildfires burning during the typical ozone season is higher in the Western United States. The commenter argues regional and local wildfire smoke can impact the DVs used to make projections at various receptors, atypical days as the result of wildfires should not have been factored into this proposed rule’s 2016, 2017, and 2018 DVs.

Commenters (0547, 0782) mention wildfires could affect whether nearby states are significantly affecting the attainment or maintenance status of Colorado monitors. Commenter (0547) also points out stratospheric intrusion increases the ozone concentration in a given area as a non-anthropogenic/natural source of ozone. Stratospheric intrusion occurs when pressure perturbations cause the boundary between the troposphere and stratosphere to ‘fold,’ allowing dry and ozone-rich air to enter into the mid- and lower troposphere. The commenter notes stratospheric intrusion was accepted as an exceptional event by the EPA in 2012 at the Boulder and Big Piney monitors located in the Upper Green River basin of western Wyoming. Nevertheless, the increased concentrations “may be indistinguishable from a peak event due to chemical production from local emissions.” The commenter provides a map demonstrating the most significant areas affected by stratospheric intrusions, mostly the Western United States.

Commenter (0782) mentions EPA accounts for wildfires more generally in its model, but it is unclear whether DMNFR monitor values that were likely influenced by atypical events were removed from the data similar to how EPA removed atypical event data in its 2019 approval of Wyoming's good neighbor SIP addressing the 2008 8-hr ozone NAAQS.

Commenter (0547) references a study that found 13 stratospheric intrusion events from April to June 2010, in contrast to prior work concluding stratospheric influence in surface air is rare.

Commenter (0547) cites “stratospheric intrusions may pose a challenge for springtime ozone over the U.S. Mountain West to stay below federal limits with domestic emissions controls.” Atypical days as the result of stratospheric intrusions should not have been factored into the proposed rule’s values for 2016, 2017, and 2018. If these atypical days had not been accounted for, the Denver-Chatfield receptor’s average baseline DV may well have been lower, which ultimately could result in the receptor no longer being a nonattainment and maintenance- only receptor for purposes of this rulemaking.

Commenters (0424, 0764) argue EPA's analysis in the proposed rule erroneously relies on air quality monitoring data influenced by exceptional events. This overstates the ozone DVs for certain monitors identified as having contribution from upwind states and results in over-control that is prohibited under the Act. The commenters believe EPA should recalculate projected DVs excluding concentrations skewed by exceptional events and determine attainment status and significant contribution metrics resulting from these new values.

Commenters (0509, 0782) show removing atypical events can have an impact on receptor projection. Commenter (0782) mentions that the EPA concluded: After removal of the atypical event-influenced data from the 2009-2013 baseline . . . the baseline maximum DV at the Douglas County receptor (2011-2013) decreases from 83 ppb to 81 ppb. To the extent Wyoming is included based on a 0.81 ppb impact to the Douglas County monitor, a decrease in impacts of 2 ppb could have substantial ramifications for Wyoming's inclusion in the Proposal.

Commenter (0782) highlights in the EPA's February 2019 approval of Wyoming's good neighbor SIP for the 2008 ozone standard, the EPA noted that it was important to account for "atypical events" affecting high ozone days in the model (*i.e.*, by removing atypical-event-influenced data).

Commenter (0509) states Section 319 of the CAA requires the EPA to disregard air quality data that has been affected by an "exceptional event." The commenter says that because EPA has not excluded ozone concentrations measured at the Chatfield monitor flagged by Colorado, EPA's proposed plan is based on improperly biased ozone design values. The commenter requests EPA to exclude monitoring data flagged by Colorado or suspected by EPA to be impacted by a fire event.

Commenter (0509) requests that the EPA eliminate improperly biased ozone DVs at the Chatfield monitor by excluding all of the monitoring data that Colorado flagged from events for informational purposes as reported in the EPA' s Air Quality System or that the EPA suspects may have been impacted by a fire event. Commenter (0509) demonstrates removing exceptional events can have a big impact with the annual 4th highest maximum value differing more than 13 ppb in 2020 depending on whether exceptional events were included in the monitored data, and 6 ppb for the 3- year average of 2018, 2019, and 2020 at the Chatfield monitor.

Commenters (0509, 0782) state that the EPA failed to exclude exceptional event air quality data. Section 319 of the CAA requires EPA to disregard air quality data that has been affected by an "exceptional event." This means that monitoring data impacted by an exceptional event can be excluded when determining an ambient standard DV. Commenter (0509) notes that on July 11, 2018, the EPA Region 8 concurred with the Colorado Department of Public Health and Environment's June 4, 2018, request to exclude ozone data at the NREL monitor influenced by wildfire exceptional events in September 2017. However, the EPA Region 8 determined that the "8-hr ozone concentrations measured at ... Chatfield ... do not currently have regulatory significance and therefore have not been reviewed. The EPA will retain the Colorado Department of Public Health and Environment's demonstration for future consideration should any of the data on which the EPA is not acting become significant for a future regulatory action". Because EPA has not excluded the ozone concentrations measured at the Chatfield monitor, EPA's Proposed Federal Plan appears to rely on improperly biased ozone DVs.

Response:

We respond to comments generally asserting the need for some different or alternative treatment of ozone transport in the western U.S. elsewhere in the record, including Section 2.4.4 of this document. We further respond to several specific comments here. As an initial matter, the EPA has made a number of updates and improvements to the 2016v2 modeling in response to comments and we find, as discussed in Section 3.2.2 (Spatial Resolution and Model Performance), that 2016v3 achieves better modeling performance and can be considered reliable to inform air quality and contribution analysis at Step 1 and Step 2, including in the western regions.

In response to comments on the impact of wildfires, the EPA agrees that there tend to be more and larger wildfires and, therefore potentially greater impacts of wildfire emissions on ozone in the western United States compared to the eastern United States. The EPA notes that emissions from wildfires were included as part of the emissions inventories used in the air quality modeling. Moreover, in the source apportionment modeling we quantified the impacts of fires (wild and prescribed) on ozone concentrations at individual monitoring sites nationwide. In a similar manner, the impacts from wildfires outside the EPA's 12 km modeling domain are transported into the U.S. as "boundary conditions" from global scale modeling, as described in the Air Quality Modeling Final Rule TSD. In this regard, the modeling accounts for the impacts of wildfires on ozone concentrations.

For this final rule, we analyzed the contributions from fires[56] and from non-US sources (*i.e.*, anthropogenic emissions in Canada and Mexico as well as anthropogenic and natural sources outside the U.S.) to quantify and compare the contributions from these types of sources at receptors in the eastern versus western U.S. Table 3-16 below provides the contributions from fires and from non-U.S. sources on average for each receptor area.[57] In this table the receptor areas are listed based on the magnitude of the contribution from fires. Overall, the contribution from fires declines progressively from west to east. The data indicate that each receptor area appears to fall into one of three geographic bins, based on the magnitude of the contributions. In the farthest western areas (*i.e.*, California Tribal Lands, Yuma, and Salt Lake City) fires contribute approximately 3 ppb. In areas that include receptors in Las Cruces, Carlsbad, and Hobbs, New Mexico, El Paso, Texas, and Denver, Colorado the contributions from fires are approximately 1 ppb which is about 2 ppb lower than in the far western areas. At receptors in Chicago, Coastal Wisconsin, and Coastal Connecticut, the contributions from fires are an order of magnitude lower than the contributions from fires at the receptors in the far western areas.

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[56] In the source apportionment modeling the fires source tag includes emissions from fires in the U.S. as well as fires from the portions of Canada and Mexico that are inside the EPA's 12 km modeling domain.

[57] The data in this table are based on the top 10-day average contribution metric which is calculated using the same method the EPA uses to calculate this metric for upwind states.

This analysis demonstrates that the EPA's modeling already captures the geographical differences between western and eastern states in terms of the contributions from fires and non-U.S. sources. However, those differences supply no inherent justification why the anthropogenic emissions of western states should be ignored or discounted in evaluating their obligations under the good neighbor provision. In view of these results, the EPA disagrees with comments that the EPA should treat western states differently than eastern states when evaluating ozone transport.

Table 3-16 (contribution in ppb)

Receptor Area	Fires
Yuma	3.1
Salt Lake City	2.9
California Tribal Lands	2.9
Denver	1.3
Las Cruces/Carlsbad/ Hobbs/El Paso	1.0
Houston/Brazoria/ Galveston	1.0
Dallas	0.9
Coastal Connecticut	0.3
Coastal Wisconsin	0.2
Chicago	0.2

In response to commenters' concerns about using 2016 wildfire emissions in the future year modeling, the EPA notes that the frequency, location, severity, and duration of wildfires are heavily influenced by meteorological conditions. Commenters did not provide any alternative approaches for modeling wildfires that may occur in 2023 or 2026. In this regard, consistent with recommendations in the EPA's air quality modeling guidance, we are using 2016 meteorology and wildfire emissions for the 2023 and 2026 model simulations in order to provide consistency between the 2016 base year modeling and the future year modeling since the base year modeling is used in conjunction with the future year modeling to project 2016-centered average and maximum design values to 2023 and 2026.

The EPA notes that when projecting design values to 2023 and 2026 the EPA removed all concurred exceptional events data from the base period DVs. To the extent commenters suggest the EPA should or is even required to complete a further analysis to identify the impact of atypical events associated with wildfires or stratospheric intrusions that are not concurred "exceptional events" under the EPA's regulations, the EPA does not concede that all such atypical events must be excluded from our modeling for interstate transport purposes.

To the extent commenters suggest the EPA should or is even required to perform an analysis to identify the impact of atypical events associated with wildfires or stratospheric intrusions, consistent with the EPA's guidance on exceptional events, while EPA welcomes early engagement with air agencies when identifying potential exceptional events and developing corresponding demonstrations, the exceptional events rule process is such that the responsibility for flagging potential event-influenced data and submitting a corresponding exceptional events demonstration is on the State where the air quality issue is located. EPA must then evaluate the demonstration and determine whether concurrence is appropriate.[58] In this action, we continue to respect the primacy of downwind states where air quality problems are located in making a judgment whether to seek EPA concurrence of an exceptional events demonstration.

This approach is consistent with how we have addressed similar circumstances in the past, as for example in approving Wyoming's 2008 ozone NAAQS transport SIP, where Wyoming applied Colorado's own analysis that high ozone levels were the result of atypical events. 83 FR 31068 (July 3, 2018). Similarly, commenters on the proposed Revised CSAPR Update (RCU) noted that the state of Connecticut submitted, and EPA concurred on, an Exceptional Events demonstration for the Westport monitoring site to remove the measured data for May 25 and 26, 2016 from the calculation of official design values. The state did not, however, submit an Exceptional Events demonstration for the Stratford and Madison monitoring sites because removing those days from these two sites did not have regulatory significance. However, both Stratford and Madison, like Westport, are located along the shoreline of Long Island Sound in coastal Connecticut. In this regard, the commenter argued that EPA should also remove the measured data for May 25 and 26, 2016 from the calculation of design values for Stratford and Madison because the smoke-influenced conditions from fires in Canada that affected the Westport site would have also affected measured data at these other two sites. Because the state had submitted technical data to support their demonstration and EPA had concurred on the Exceptional Events determination for Westport, the EPA performed a sensitivity analysis in the RCU in which the data for May 25 and 26, 2016 were removed when projecting average and maximum design values at Stratford and Madison.

Based on the EPA's Step 2 modeling for this final rule, California and Utah are each linked to three receptors in Denver (i.e., Chatfield, monitor ID 080350004, Rocky Flats, monitor ID 080590006, and the National Renewable Energy Laboratory, monitor ID 080590011) and one receptor in Ft. Collins, CO (monitor ID 080690011). Out of abundance of caution, the EPA performed a bounding analysis for the Rocky Flats monitor to determine if this monitor would still be identified as a nonattainment receptor in 2023, and therefore, California and Utah would remain linked, even if all flagged data in 2014 through 2018 were removed when calculating projected 2023 average and maximum design values at this monitor. In brief, the EPA followed the same approach for projecting future year design values as described in the Air Quality Modeling TSD for this Final Rule, except that data flagged as potentially affected by wildfires were removed from the calculations. Specifically, the EPA identified the days in

[58] 81 FR 68216 (October 2016), Treatment of Data Influenced by Exceptional Events.

2014 through 2018 that were flagged as potentially influenced by wildfires at the Rocky Flats monitor based on Informational Flagged Data reports prepared by the Colorado Department of Public Health and Environment (CDPHE). A copy of these reports is provided in the file "Colorado Flagged Data_2014-2018" which can be found in the docket of this final rule. To calculate adjusted design values for this sensitivity analysis, the EPA first removed the flagged MDA8 ozone concentrations in each of the five years, 2014 through 2018, that then re-ranked the MDA8 ozone concentrations to identify the 4th highest concentrations in each year, excluding the days with flagged data. Next, adjusted design values were calculated for 2016, 2017, and 2018 by calculating the three-year average of the 4th highest concentrations in each year. The adjusted design values in 2016, 2017, and 2018 were then averaged to calculate an adjusted 2016-centered average design value and to identify the adjusted maximum design value during this time period. The adjusted 2016-centered average and maximum designs were projected to 2023 by multiplying both of these values by the 2016 to 2023 modeling-base Relative Response Factor (RRF) for the Rocky Flats monitoring site. The results of this sensitivity analysis indicate that Rocky Flats would still be a projected 2023 nonattainment receptor to which California and Utah are linked, even if all 2014 to 2018 flagged data at this monitor were determined to be atypical. In this regard, the EPA is not making a finding as to whether or not any or all of these days represent atypical events.

	Design Values			**2016-Centered**			**2023 Projected**	
	2016	**2017**	**2018**	**Average**	**Max**	**RRF**	**Average**	**Max**
No Days Removed	77	77	78	77.3	78	0.9426	72.8	73.5
Flagged Days Removed	76	75	76	75.7	76	0.9426	71.3	71.6

In response to the comment about CAA section 319, EPA provides the following clarifying information. In 2005, Congress provided the statutory authority for the exclusion of data influenced by "exceptional events" meeting specific criteria by adding section 319(b) to the CAA. To implement this 2005 CAA amendment, EPA promulgated the 2007 Exceptional Events Rule. 72 FR 13560 (March 22, 2007). The 2007 Exceptional Events Rule created a regulatory process codified at 40 CFR parts 50 and 51 (§§ 50.1, 50.14, and 51.930). These regulatory sections, which superseded EPA's previous guidance on handling data influenced by events, contain definitions, procedural requirements, requirements for air agency demonstrations, criteria for EPA's approval of the exclusion of event-affected air quality data from the data set used for regulatory decisions, and requirements for air agencies to take appropriate and reasonable actions to protect public health from exceedances or violations of the NAAQS.

In 2016, EPA promulgated a comprehensive revision to the 2007 Exceptional Events Rule. 81 FR 68216 (Oct. 3, 2016). Under the Exceptional Events Rule, if a state demonstrates to EPA's satisfaction that emissions from an event caused an exceedance or violation of the NAAQS, EPA must exclude that data from use in determinations of regulatory significance.

In addition to having regulatory significance and meeting certain procedural requirements for submitting an exceptional events demonstration, the demonstration must include (1) a narrative conceptual model describing the event(s) causing the exceedance or violation, (2) a demonstration of a clear causal relationship between the event and the monitored exceedance or violation, (3) analyses comparing the event-influenced concentration to concentrations at the same monitoring site at other times to support the clear causal relationship, (4) a demonstration that the event was both not reasonably controllable and not reasonably preventable; and (5) a demonstration that the event was caused by human activity that is unlikely to recur at a particular location or was a natural event. EPA reviews each request to exclude data under the Exceptional Events Rule on a case-by-case basis using a weight of evidence approach. 40 CFR 50.14(c)(3)(iv).

In response to the comment on the EPA's evaluation of an exceptional event demonstration submitted by the CDPHE June 4, 2018 request to exclude ozone data, the EPA acknowledges the comment that CDPHE flagged events for informational purposes as reported in EPA's Air Quality System (AQS). From 2017 to 2020, for the five monitoring sites listed in the comment, CDPHE used an "I" series flag for 172 days in AQS to initially identify values they believed may have been affected by an event, but for which they did not yet know if they would request exclusion or develop an exceptional event demonstration. Specifically for the Chatfield monitor, CDPHE used an "I" series flag for 27 days. CDPHE only used "R" series flags at two of the five sites, each with two days, resulting in a total of four "R" flagged days, for which CDPHE ultimately submitted corresponding demonstrations. "R" flags are intended to identify data that might have regulatory significance, for which an air agency intends to request exclusion and submit a demonstration. AQS only allows EPA to place concurrence flags on data identified with an "R" flag. Therefore, EPA does not have the authority to exclude monitoring data flagged for informational purposes in EPA's AQS. See 81 FR 68216, 68263 (Oct. 3, 2016). However, based on the sensitivity analysis performed and summarized above with respect to the Rocky Flats receptor, this circumstance with respect to the Chatfield monitor would not affect our regulatory determinations with respect to any upwind states included in this final rule in any case. The EPA has made a number of updates and improvements to the 2016v2 modeling in response to comments and we find, as discussed in Section 3.2.2 (Spatial Resolution and Model Performance), that 2016v3 achieves better modeling performance and can be considered reliable to inform air quality and contribution analysis at Step 1 and Step 2, including in the western regions.

[1] *See, e.g.*, 87 FR 31443 at 31454.

[2] 81 FR 68216 (October 2016), Treatment of Data Influenced by Exceptional Events.

[3] In the source apportionment modeling the fires source tag includes emissions from fires in the U.S. as well as fires from the portions of Canada and Mexico that are inside the EPA's 12 km modeling domain.

[4] The data in this table are based on the top 10-day average contribution metric which is calculated using the same method the EPA uses to calculate this metric for upwind states.

Comment:

Commenter (0758) urges EPA to do an analysis to determine which states contribute more than 1 percent to wintertime ozone in the Uinta Basin, the Denver Metro/North Front Range, and other areas with areas with wintertime ozone problems and then come up with emissions reduction requirements for those upwind contributors.

Commenter (0758) states that the EPA has failed to consider wintertime ozone. Wintertime ozone is an important aspect because it is a problem in multiple oil and gas basins in the West. For example, the EPA designated the Upper Green River Basin Area, Wyoming as nonattainment for the 2008 8-hr ozone NAAQS. This nonattainment designation was due to wintertime ozone levels. Wintertime ozone also plagues areas which were not necessarily designated nonattainment because of wintertime ozone, but will still have a very difficult, if not impossible, time coming into attainment without addressing wintertime ozone. The commenter references the Platteville Atmospheric Observatory (PAO) monitor to demonstrate wintertime ozone events. The commenter also states EPA has completely ignored upwind states' contributions to the Denver Metro/North Front Range ozone nonattainment area. The EPA must do an analysis of monitoring data for other western areas with significant oil and gas production and winter weather to determine if they also have a wintertime ozone problem.

Response:

As stated in the Air Quality Modeling Proposed Rule TSD, the Uinta Basin nonattainment area was designated as nonattainment for the 2015 ozone NAAQS not because of an ongoing problem with summertime ozone (as is usually the case in other parts of the country), but instead because it violates the ozone NAAQS in winter. The main causes of the Uinta Basin's wintertime ozone are sources located at low elevations within the Basin, the Basin's unique topography, and the influence of the wintertime meteorologic inversions that keep ozone and ozone precursors near the Basin floor and restrict air flow in the Basin. Because of the localized nature of the ozone problem at these sites we have not identified monitors within the Basin as receptors in Step 1. Studies have found that meteorological inversion conditions and the unique topographic features of the Uinta Basin combined with local ground-level emissions of VOC and NO_X result in winter conditions that aid in the formation of ozone in the Uinta Basin.[59] The Uinta Basin is a bowl surrounded by much higher mountain ranges with varying heights from over 7,500 to 13,000 feet. In environments such as this one, cooler, denser air becomes trapped in the Basin when warmer air overrides the area during high pressure events, creating an inversion. Normal atmospheric mixing does not occur in this type of environment; instead, pollutants settle due to high-pressure ridges and low surface winds within the Basin. Only when there are cooler temperatures aloft, with high winds, or when surface warming occurs, can a temperature inversion break down and allow pollutants to mix out of the Basin.

[59] Final Report: 2014 Uinta Basin Winter Ozone Study. https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2015-021002.pdf

Snow cover also plays an essential role in winter ozone episodes in the Uinta Basin. Snow acts as a highly reflective surface for both visible and UV radiation, so the sun's rays cannot reach the ground covered by snow to warm the surface, thereby enhancing the stability of the inversion layer. In addition, because the UV radiation passes through the air column again as it is reflected away from the ground, the total UV flux is nearly doubled compared to conditions without snow cover, and the increased UV flux enhances the photochemical reactions of VOC and NO_X that form ozone. At night, cold down-sloping winds from the surrounding mountains can strengthen the inversion. The super-stable atmosphere allows emissions to accumulate, and the sunny conditions during the daytime let photochemical reactions take place. Only emissions with enough heat, plume velocity, or stack height can escape the inversion, depending on the boundary layer height, and enter the unstable atmosphere above the inversion.

As noted above, under wintertime temperature inversion conditions, cold air pools form at the lower elevations in the Basin, and pollutants are trapped in the pooled air under the temperature inversion. Providing that snow cover is present, inversions can persist for periods longer than a week, until energetic weather systems break the temperature inversion and sweep out trapped pollutants. While trapping locally emitted pollutants under an inversion layer within the Uinta Basin, the inversion layer also limits transported pollutants from outside the Basin from entering and contributing to ozone formation, as warmer air, carrying upwind emissions, tends to pass above and across the colder air trapped below. Once a temperature inversion is present, there is limited, if any, transport of pollutants horizontally or vertically that could impact local photochemistry.[60] (Lyman, et.al., 2015). In fact, even different areas of the Basin are "relatively isolated from each other, allowing spatial factors like elevation and proximity to sources to strongly influence ozone concentrations at individual sites." *Id.*

The same analysis applies to Upper Green River Basin area in Wyoming, *see* 87 FR 61249 (Oct. 11, 2022), and based on this analysis, we do not find other states linked to wintertime ozone conditions in these two areas.

3.4.3.2 Projecting Future Year DVs Based on Actual Conditions

Comment:

Commenter (0509) states that the EPA's proposed transport rule is flawed because it uses inconsistent emissions to define future year nonattainment and state contributions rather than defining necessary controls and conducting overcontrol analysis. The commenter notes that the differences between the Step 1 and 2 CAMx 2023 and 2026 base case emissions and the Step 3 AQAT 2023 and 2026 Engineering Analysis baseline emissions were quite large; in some

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[60] Lyman, S, Trang, T. Inversion structure and winter ozone distribution in the Uintah Basin, Utah, U.S.A. Atmospheric Environment. 123 (2015) 156-165.

instances, the discrepancy at individual EGU NO_X emissions was as much as 100 percent, meaning that the models were unfit to accurately estimate emissions from Wyoming EGUs. According to the commenter, these changes in the state NO_X future year emissions projections between the Steps 1 and 2, and Step 3 in the proposed rule makes the proposed rule inconsistent and incoherent. Moreover, the commenter also states that the EPA's proposed rule overcontrols Wyoming emissions because Chatfield is an attainment monitor in 2026, asserting that the EPA's CAMx modeling overstates the projected 2023 and 2026 ozone DVs at Chatfield, and that by 2026, Chatfield should be an attainment monitor so Wyoming should not be included in the proposed rule 2026 EGU and non-EGU NO_X controls. The commenter notes that the EPA recognizes that the Douglas County receptor is expected to be in attainment by 2026 and concludes that EGU and non-EGU reductions in the state of Wyoming would constitute over-control.

Response:

In regard to comments on possible overcontrol in Wyoming, the EPA explains in preamble Section IV.F that the Agency is deferring action at this time for Wyoming with respect to its proposed FIP actions for those states. See further analysis of overcontrol in Section V.D.4 of the preamble.

Comment:

Commenter (0509) also indicates that the EPA's analysis failed to include emissions controls in the DMNFR Nonattainment Area that would reduce future year ozone DVs, including:

- Electric Vehicle sales penetration in Colorado;
- Colorado's adoption of California's motor vehicle emissions standard;
- Mandatory NO_X and VOC emissions controls required under EPA's proposed redesignation of the DM/NFR 2008 Ozone Nonattainment area from serious to severe; and
- Mandatory NO_X and VOC emissions controls required under EPA's proposed redesignation of the DM/NFR 2015 Ozone Nonattainment area from marginal to moderate.

Response:

Regarding the reflection of electric vehicles in the modeling platform, the EPA did not base the proportion of electric vehicles in the analytic years on the vehicle populations from MOVES3 as asserted by the commenter. Instead, for all states, the EPA based the vehicle miles traveled data for the analytic years on year 2020 vehicle registrations by fuel type (*e.g.*, gasoline, diesel, electric) and by county, and then adjusted the 2020 data to the analytic years using fuel-specific trends based on AEO 2022. This method made use of the latest information available to the EPA at the time the modeling inputs were prepared. In contrast, for the proposal modeling, the vehicle miles traveled were based on registration data from the calendar year 2017 and were then projected to the analytic years using fuel-specific trends based on an earlier version of the AEO. In addition, we note that due to the rate of turn-over of the fleet, the total fraction of electric vehicles in the fleet will increase more slowly than the increase in electric vehicle sales.

The Colorado Electric Vehicle Plan 2020[61] says that by "achieving its goal of 940,000 EVs by 2030, the state could see significant environmental benefits that include emissions reductions. As noted in the 2018 Colorado Electric Vehicle Plan, Colorado could experience an annual reduction of ozone forming pollutants estimated at 800 tons of NOx, and 800 tons of volatile organic compounds (VOC)." If these numbers are correct, the ozone season ozone-precursor emissions would be reduced by approximately 600 tons, which is only 0.6 percent of the total ozone-precursor emissions projected for Colorado, and that level of reduction would only be achieved by 2030, well after the analytic years for this action. These changes, alone, are unlikely to bring the state of Colorado back into attainment for the 2015 ozone NAAQS.

The commenter mentions the impact of the California's CAA waiver on other states like Colorado and noted that those emissions must be accounted for accurately. We note that the emissions rates included in MOVES3 reflect the national Tier 3 program, which harmonizes emissions rates for NO_X and VOC with the California LEV program starting with model year 2017 and are applied in all states. MOVES3 was used for both the proposal modeling and the modeling for this action. The Colorado ZEV regulations are not explicitly accounted for in the 2016v2 modeling, although as discussed above, in the 2016v3 platform the EPA used county-specific data from the 2020 NEI regarding the proportion of electric vehicles and then projected those to 2023 and 2026 using factors computed based on the AEO 2022 projected growth of electric vehicles.

We anticipate that some emission reductions will come from forthcoming reformulated gasoline (RFG) requirements related to the Denver Metro / North Front Range (DM/NFR) NAA reclassification from Serious to Severe nonattainment for the 2008 ozone NAAQS. However, these will most likely be too small on their own, or in combination with other planned vehicle programs in the state, to change the attainment status of Denver. Because conventional gasoline is already limited to 10 ppm sulfur, the impact on NO_X emissions due to the adoption of RFG will be minimal, although there will be a reduction of evaporative VOC emissions starting in the summer of 2024. We note that the emissions rates included in MOVES3 reflect the national Tier 3 program, which harmonizes emissions rates for NO_X and VOC with the California LEV program starting with model year 2017 and are applied in all states. While there are other NO_X and VOC control requirements that will likely come into place due to reclassification actions for Colorado for the 2008 and 2015 ozone NAAQS, these effects are not known with certainty and could not be incorporated in emissions inventories used for the 2016v3 modeling. Nonetheless, because Colorado is a "home state," our analysis at Step 3 takes into account a "fair share" of emissions reductions from Colorado in assessing air quality effects of the rule, including for purposes of our overcontrol analysis. See Section V.D.4 of the preamble. The relationship of the timing and effects of downwind vs upwind emissions reductions is further discussed in Section IV.A of the preamble and Section 3.1 of this document.

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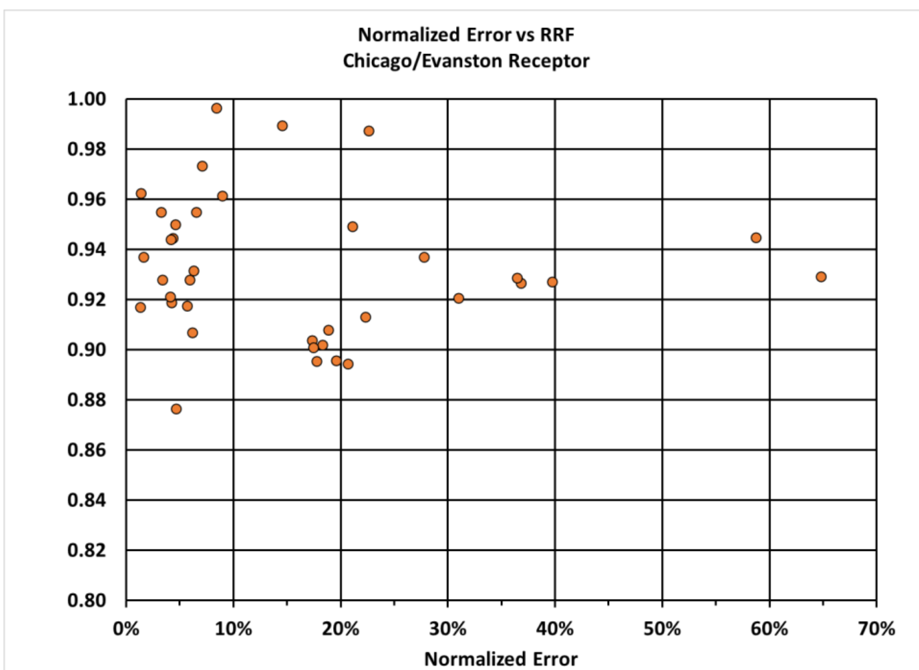
[61] The Colorado Electric Vehicle Plan 2020 can be accessed via *https://energyoffice.colorado.gov/zero-emission-vehicles/colorado-ev-plan-2020.*

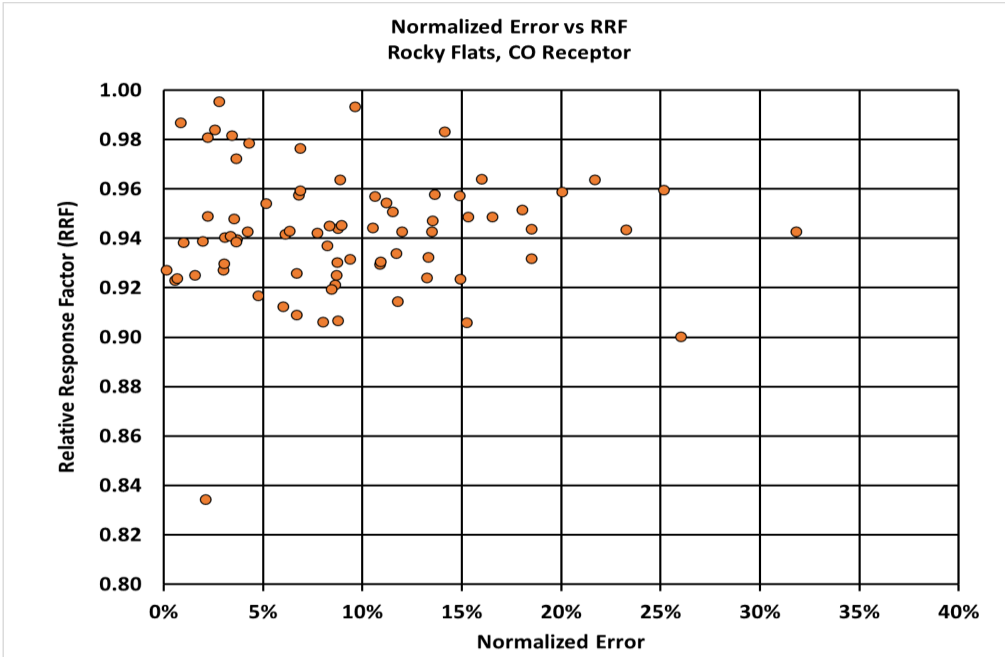
Comment:

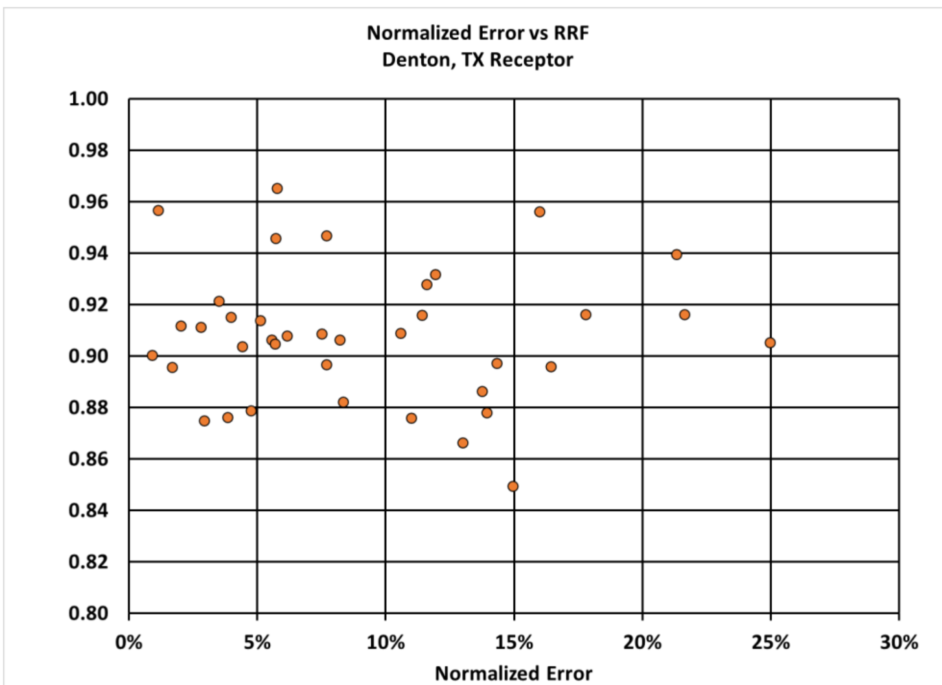
Commenter (0531 Ameren) notes that the EPA's use of the RCF and RRF to determine Missouri's significant contribution compounds the modeling inaccuracies. The RRF which is the average ratio of the two modeled concentrations on the top 10 modeled base year concentrations has the same relative error. The RRF is then multiplied by the actual observed ozone DV for the base year (2016) to estimate the future year DV for that monitor location. The error in the DV calculation is equal to the normalized mean error for the RRF calculation. The error in the RCF calculation is similar to the RRF error. The RCF error can be estimated based on the normalized mean error of the base year modeled MDA8 ozone concentrations of the days used to calculate the RCF.

Response:

The EPA disagrees with commenter’s assertion that the error in the DV calculation is equal to the normalized mean error for the RRF calculation and that the error in the RCF calculation is similar to the RRF error. In response to this comment the EPA conducted an analysis to determine if there is any clear relationship between base year (*i.e.*, 2016) model error and the response of the EPA’s CAMx modeling to emissions changes between 2016 and 2023. The figures below show the normalized mean error on individual days as a function of model response (*i.e.*, daily RRF) at the Chicago/Evanston, Denver/Rocky Flats, and Dallas/Denton receptors. The plots are based on days with modeled MDA8 ozone concentrations greater than or equal to 60 ppb in the grid cells used to project 2023 DVs. As evident from these plots, there is no discernable relationship between model error and model response.







Comment:

Commenter (0758) states the EPA inaccurately modeled Ozone levels in Harford County, Maryland to erroneously exclude North Carolina from the proposal. Harford County has never attained the 2015 ozone NAAQS and the 2021 4th highest 8-hr daily maximum of 73 ppb will be averaged into the calculation of the 2021-2023 DV. The EPA nevertheless projects a 2023 max “no water” DV for monitor 240251001 of 64.8 ppb. That is, in spite of DVs remaining at or above 72 ppb for the past six consecutive DVs, the EPA projects that the DV fall 7.2 ppb in just two years.

Response:

In response to the commenter’s concern about projected 2023 DVs in relation to recent measured at the Harford County, Maryland monitoring site, the EPA examined the trends in recent measured at this location. The first table below provides the 4th high maximum daily average 8-hr ozone concentrations that are used to calculate 2017 through 2021 and preliminary 2022 DVs. The second table provides the DVs from 2017 through 2021 along with the preliminary DV for 2022. The measured data show that the 4th high ozone value decreased from 77 ppb in 2019 to 66 ppb in 2022 which averages out to approximately 3 ppb per year. If that trend were to continue, the 2023 4th high value would be 62 ppb which would result in a 2023 DV of 67 ppb [(73 + 66 + 62)/3]. While this calculation is not intended to predict the ozone concentration in 2023, it does suggest that a projected 2023 DV below 71 ppb would be consistent with trends in recent measured data.

Table 3-16

4th Maximum MDA8 Ozone Concentration (ppb)							
2015	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***Preliminary 2022***
74	77	76	74	77	67	73	66

Table 3-17

	Ozone DVs (ppb)					
	2017	***2018***	***2019***	***2020***	***2021***	***Preliminary 2022***
	75	75	75	72	72	68

3.4.4 Other Receptor Topics

Comment:

Commenter (0411) states the findings from both the LADCO and EPA photochemical modeling results show the shore of Lake Michigan is below the 2008 standard, and below the 2015 threshold of 0.070 ppb. The findings also show ozone concentrations are expected to continue to decrease across the area, which conflicts with the finding that Minnesota, Wisconsin, and Texas are linked to contributing above the impact threshold for the 2015 Ozone NAAQS. At a minimum, it demonstrates inconsistencies and potential errors where EPA found the IPM modeling platform (used in the current rulemaking) to be superior to the LADCO photochemical analysis and the photochemical analysis performed by the TCEQ’s in determining Minnesota's and Texas's contributions in modeling performed for the 2015 Ozone NAAQS to inform their SIP. Again, in the time allowed to evaluate the supporting information in the docket Xcel Energy has been unable to identify any specific information in the record that addresses or attempts to reconcile these conflicting findings.

Response:

The EPA notes that the commenter did not specify which findings of LADCO and EPA they viewed to be in conflict. In any event, the EPA disagrees that receptors near the shore of Lake Michigan are not expected to have difficulty attaining or maintaining the NAAQS. Based the EPA's 2016v3 modeling developed for this final rule Minnesota is linked to the Chicago/Alsip maintenance-only receptor with a contribution of 0.85 ppb. As shown in the table below, measured DVs at this monitor have exceeded the NAAQS since 2017 and the preliminary 2022 DV is above the NAAQS (72 ppb), the preliminary 2022 4th high concentration is 73 ppb, and the EPA's projected maximum DV is 71.9 ppb. Based on these data, the EPA believe that Alsip receptor is at risk of continued nonattainment in 2023. As shown in the tables below, Texas is linked to 20 receptors in 2023. Of those 20 receptors, 11 are identified based on model projections for 2023, while 9 are identified as violating-monitor receptors, as described in Section IV.D of the preamble. In addition, of the 20 receptors to which Texas is linked, 14 are located in the Lake Michigan area. Comparing the model-projected 2023 average and maximum DVs to measured data in 2021 and preliminary data in 2022 indicate that the projections are likely to understate actual ozone DVs in 2023. All of the receptors in the Lake Michigan area measured nonattainment in 2021 and in 2022 based on preliminary data and five of these receptors had 2021 measured DVs at or above 74 ppb. Moreover, Texas contributes over 1.00 ppb to 11 of the 14 receptors in the Lake Michigan area. Thus, the current measured data strongly indicate that the receptors in the Lake Michigan areas to which Minnesota and Texas are linked will continue to have a nonattainment problem in 2023.

Table 3-18

Modeling-Based Receptors in 2023													
Monitor ID	**State**	**County**	**2023 Average**	**2023 Maximum**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022***	**2021 4th High**	**2022 4th High***	**Impact From Texas**
170310001	IL	Cook	68.2	71.9	73	77	75	75	71	72	68	73	1.09
170314201	IL	Cook	68.0	71.5	72	77	74	77	74	74	75	70	1.05
170317002	IL	Cook	68.5	71.3	73	77	75	75	73	74	78	71	1.95
350130021	NM	Dona Ana	70.8	72.1	72	74	77	78	80	81	86	80	4.74
350130022	NM	Dona Ana	69.7	72.4	72	74	76	74	75	75	79	75	3.59
350151005	NM	Eddy	69.7	74.1	68	74	79	78	77	77	80	79	1.91
350250008	NM	Lea	69.8	72.2	67	70	71	68	66	66	68	72	2.17
550590019	WI	Kenosha	70.8	71.7	78	79	75	74	74	75	79	70	1.54
550590025	WI	Kenosha	67.6	70.7	73	77	74	74	72	73	72	71	1.83
551010020	WI	Racine	69.7	71.5	74	78	74	73	73	75	78	70	1.57
551170006	WI	Sheboygan	72.7	73.6	80	81	75	75	72	75	73	77	1.03

* Data for 2022 are preliminary and based on measured data as of January 3, 2023

Table 3-19

Violating-Monitor Maintenance-Only Receptors													
Monitor ID	**State**	**County**	**2023 Average**	**2023 Maximum**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022***	**2021 4th High**	**2022 4th High***	**Impact from Texas**
170310032	IL	Cook	67.3	69.8	72	75	73	74	75	75	77	72	1.40
170311601	IL	Cook	63.8	64.5	69	70	68	71	72	73	72	71	0.78
181270024	IN	Porter	63.4	64.6	69	71	70	71	72	73	72	73	1.32
261210039	MI	Muskegon	67.5	68.4	74	76	74	76	74	79	75	82	1.52
260050003	MI	Allegan	66.2	67.4	73	73	72	73	75	75	78	73	1.68
350130008	NM	Dona Ana	65.6	66.3	68	68	70	70	72	76	79	78	3.83
350011012	NM	Bernalillo	63.8	66.0	67	69	71	71	72	73	76	74	0.78
390850003	OH	Lake	64.3	64.6	73	74	73	74	72	74	72	76	0.78
550890008	WI	Ozaukee	65.2	65.8	71	72	71	71	71	72	72	72	1.24

* Data for 2022 are preliminary and based on measured data as of January 3, 2023

3.4.4.1 Alleged Overly Optimistic Model Ozone Level Predictions

Comment:

Commenter (0758) notes that the EPA's modeling underpredicts future ozone levels in Brazoria County, Texas, and in Douglas County, Colorado, resulting in weaker protections, and should be updated in the final rule. Although a key receptor in Brazoria County, Texas, (480391004) is projected to continue to have maintenance issues in 2026, those issues resolve following reductions from EGUs and other sources according to the proposed rule's analysis. Similarly, a receptor in Douglas County, Colorado, (80350004) would continue to have maintenance issues in 2026 were it not for the rule's requirements. These receptors are important because Arkansas and Mississippi are only linked to Brazoria County in 2026, and Wyoming is only linked to Douglas County in that year. The commenter states several factors likely contribute to EPA's underestimation of future ozone levels and should be corrected in the final rule. First, the modeling approach used for the proposed rule does not incorporate and account for recent monitored ozone values, even though those monitored values are already available and will be used to calculate the ozone DVs used to determine whether the ozone standard is being attained and maintained in 2023. Instead, the EPA's model uses the average ambient 8-hr DVs for the period 2014 to 2018" projected forward to the years around 2023.

1. Interstate pollution contributes to states' ongoing difficulties in attaining and maintaining the 2015 ozone standard.
    a. Ozone pollution remains problematic across the United States. In fact, 213 monitors show a DV (DV) of greater than 70 ppb in 2020, see Figure II.1.

Unhealthy ozone levels persist along the eastern seaboard in Connecticut, New York, Maryland, and Washington D.C., as well as in the Great Lakes region and Texas. Ozone levels are unhealthy and are actually increasing in several regions of the western United States. These monitoring data demonstrate the clear need for additional reductions in ozone precursor emissions.

2. Ozone problems are worsening in several states.
    a. Phoenix, Arizona continues to have elevated ozone concentrations with many local sites' 2020 DVs exceeding the standard, and the DVs for a number of sites are rising rather than improving. See Figure II.3 and Table II.3. The high elevation site at Humboldt Mountain, in the Tonto National Forest (040139508, data not shown), is also exceeding the standard, with a DV of 73 ppb for the last 6 DVs, indicating the possible impact from interstate transport on the nearby Wilderness Area.
    b. New Mexico has five sites with 2020 DVs exceeding the standard; seven sites are trending upwards since 2016. See Figure II.4. The Desert View monitor in the New Mexico portion of the El Paso-Las Cruces Nonattainment Area (350130021) has a 2020 DV of 78 ppb.
    c. Some sites in Nevada have persistent or increasing ozone levels (*e.g.,* 320310031, 320312009). Ozone levels in Colorado are also increasing and exceeding the standard, not only in the designated Denver Metro/North Front Range sites but also in Colorado Springs (El Paso County) as identified in Table II.5 below and a newer site in Boulder, Colorado (080130014). The Fort Collins site (80690011), while not increasing, continues to have chronically and consistently high ozone levels. Figure II.5 shows DVs for some of the sites in Colorado since 2015.
    d. While some Texas sites are seeing declining ozone levels, others are getting worse. Ozone levels in the El Paso area have increased dramatically since 2016 (481410037, 481410044). And ozone levels remain unhealthy around the large metropolitan areas of Houston and Dallas as well as in San Antonio (480290032, 480290052).
    e. California's ozone levels continue to be high, with some regions worsening. The EPA should have included the San Francisco Bay area Livermore site (060010007) as a receptor site in modeling. This CA site had its last 4^{th} highest exceedance in 2019 (72 ppb), and data for 2021 have this site at 72 ppb. This location is slightly higher in elevation (greater than400') and is adjacent to significant traffic corridors including routes connecting the I-5 trucking route to just east of 880 corridor that sees significant truck traffic and gridlock. Other California sites that should be included as receptor sites because they are both in designated nonattainment areas and currently exceeding the health standard are Eastern San Luis Obispo (060798005), Sutter Buttes (061010004), and Tuscan Buttes (061030004).
    f. Three Maryland sites' 2020 DVs exceeded the standard, and the coastal area of the state continues to experience persistently high levels. Excluding 2020, which

is influenced by the COVID-related lockdowns in the Eastern US, and instead looking at 2019 DVs as more representative of Maryland's ozone problem, the state had 6 locations exceeding the standard. In 2021, Maryland had 17 exceedance days reported by the Maryland Dept. of the Environment with several sites' 4th highest ozone levels rebounding back above 70 ppb after falling in 2020. The Agency has detailed the complex meteorology that contributed to ozone exceedances in 2021 and identified interstate transport as a cause, in combination with local emissions, stagnation, and remixing that occurs over multiple days from onshore breezes and upper atmospheric reservoirs. Relief from interstate transport would help to improve Maryland's ongoing unhealthy air quality.

Commenter (0758) states EPA's overly optimistic modeling has significant consequences for its proposed transport rule. In some instances, by modeling certain monitors into attainment by 2023, despite strong evidence that key downwind monitors will not actually attain, entire states are excluded from the rule (*e.g.,* North Carolina, New Mexico, Arizona). In other instances, by modeling certain monitors into attainment by 2026, when relevant downwind monitors show persistent nonattainment, the budgets and compliance obligations of other states are dramatically reduced (*e.g.,* Alabama, Tennessee). Furthermore, the divergence of EPA's projected ozone levels from real-world observations and trends cannot be explained by random variation, because projected ozone levels are much more frequently understated than overstated in comparison to measured values. Indeed, the tendency of EPA's projections consistently to understate ozone levels overall is starkly apparent in the data. The commenter adds the 2020 monitored DV exceeds EPA's 2023 projected average DV at 94 out of the 111 nonattainment and maintenance receptors for which EPA has made projections, usually by large margins. By contrast, the EPA's projections exceed measured DVs at only 12 of these 111 monitors, and almost all of these are by very small margins.

Commenter (0758) argues the tendency of the EPA's projected ozone DVs to understate real-world levels is borne out by past experience. For instance, in the CSAPR Update, the EPA used a similar methodology to the approach here, projecting DVs in 2017 based on a five-year base period from 2009 to 2013. In retrospect, the projected values often proved much lower than observed levels. For example, for one receptor in Fairfield, Connecticut, (90010017), the EPA projected a 2017 average DV of 74.1 ppb; the measured 2017 DV was 79 ppb. For Bucks County, Pennsylvania, (420170012), the EPA projected a 2017 average DV of 70.3 ppb; the measured 2017 DV was 80 ppb. And for one receptor in Kenosha County, Wisconsin, (550590019), the EPA projected a 2017 average DV of 66.3 ppb; the measured 2017 DV was 78 ppb. Although the EPA's projections were not low in every instance, the preponderance of underestimates when the projected values are checked against real-world observations calls into question the EPA's methodology and demonstrates the consistent tendency of the EPA's approach towards underestimation.

Commenter (0758) continues, the EPA must update its modeling to more closely align it with real world ambient ozone trajectories and should begin by addressing overly optimistic assumptions. Moreover, the EPA must include in its final contribution analysis all monitors that may fail to attain or maintain the NAAQS by 2023 under realistic assumptions. For dozens of monitors currently violating the 2015 ozone standard, the EPA projected ozone levels to decline by between 7.1 and 10.6 ppb in a period of only three years. This magnitude of improvement is contrary to recent air quality trends for many of these monitors, which reveal ozone levels flatlining or increasing.

Commenter (0758) believes Arizona exemplifies the inaccuracy of the EPA's 2023 DV modeling. Two receptor sites that exceed the standard and are not included in modeling are to the SE of Phoenix (40218001) and on the eastern side of the Mazatzal Mountains and Wilderness Area near the Tonto National Monument (040070010). Maricopa County has 19 monitors with 2019-2021 DVs violating the 2015 ozone NAAQS. Six of these monitors have DVs of 75 ppb or higher for 2019-2021, and 4th highest 8-hr maximum daily average ozone concentrations were as high as 82 ppb at these monitors in 2021. Moreover, Maricopa monitors show alarming worsening trends. The number of days where the 8- hour maximum daily ozone concentration exceeded 70 ppb skyrocketed beginning in 2020, jumping from 33 days in 2019 to 189 days in 2020 and 221 days in 2021. Yet, commenter (0758) states, the EPA modeling projects that no monitors in Maricopa County will be out of attainment of the 2015 ozone standard come 2023. This is simply not credible given current ozone levels and recent ozone trends.

Commenter (0758) continues, Arapahoe County, Colorado, similarly illustrates the over-optimism of the EPA's modeling. DVs at both Arapahoe County monitors have been increasing in recent years. At monitor 080050002, the 2019-2021 DV hit 80 ppb, the highest level in the past ten years, driven in part by a 2021 4th highest 8-hr daily maximum level of 84 ppb. The number of ozone exceedance days also jumped in 2021 to the highest number in more than two decades. Despite these recent trends, the EPA projects that Arapahoe County will have a maximum "no water" 2023 DV of only 68 ppb, a 12 ppb drop in just two years' time. This again defies credibility.

Commenter (0758) states the EPA arbitrarily modeled Collin, Denton, Harris and Tarrant Counties in Texas to irrationally exclude Alabama and Tennessee from the Post-2023 Phase of the rule. Collin County, Texas, has consistently recorded violations of the 70 ppb ozone standard for the past ten years. The EPA nevertheless projects that Collin County will attain the ozone standard in 2023 with a "no water" max of only 66.8 ppb. Given that the 4th highest 8-hr daily maximum from 2021 was 81 ppb, 4th highest daily ozone levels would have to average 59.7 ppb in 2022 and 2023 for Collin County to achieve the "max" 2023 DV EPA projects and would have to average below 66 ppb in 2022 and 2023 to attain the 2015 standard by 2023. Harris County has also demonstrated persistent nonattainment of the 2015 ozone standard. The EPA projects that Harris County will fall just below the threshold for a maintenance monitor in 2026 with a 2026 "no water" max of 70.8 ppb. As with Collin County, the EPA needs to provide some plausible explanation for such precipitous and dramatic projected improvements in air quality. Denton County, Texas continues to struggle to meet the 2015 ozone standard. The EPA projects that in only two years this monitor will be meeting the 2015 ozone standard. Tarrant County has four monitors that continue to violate the 2015 NAAQS. In the past ten years, only one of these monitors had a DV that ever dipped below 71 ppb (to 70 ppb for one year in 2018). The EPA projects that all five of the Tarrant County monitors will have max "no water" 2021-2023 DVs well below the 70 ppb standard (ranging from 65.3 ppb to 68.7 ppb).

This degree of rapid improvement in ozone levels is not realistic given current levels and recent trends.

Response:

In response to these comments and other similar comments, the EPA compared the projected 2023 maximum DVs based on the 2016v3 modeling for this final action to the corresponding 2021 and preliminary 2022 DVs based on measured data at individual monitoring sites nationwide. The table below provides the projected 2023 maximum DVs at modeling-based receptor sites nationwide along with the difference between these maximum DV and the measured DVs in 2021 and 2022 (preliminary). The data in the table indicate that of the 33 receptors, projected maximum 2023 DVs are more than 1 ppb lower than the corresponding 2021 (2022) preliminary DVs at 24 (22) receptors. In addition, the EPA has identified 49 monitoring sites that are projected to be in attainment based on model-projected 2023 average and maximum DV but are measuring nonattainment based on 2021 and preliminary 2022 data. As described in the preamble of this final rule, the EPA has identified these 49 monitoring sites as "violating-monitor" maintenance-only receptors in 2023. The "violating monitor" receptors and the upwind states linked to these receptors can be found in the Air Quality Modeling Final Rule TSD. As described in Section III.B of the preamble, the violating monitor 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 and is only being used as a receptor category on a confirmatory basis in this rulemaking. 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.

In response to commenter's concerns regarding projections for specific monitoring sites, among the set of violating-monitor receptors are monitors in Maricopa County, Arizona, Arapahoe County Colorado, Clark County, Nevada, and Collin, Denton, and Tarrant counties, Texas. In addition, the EPA's 2016v3 modeling has identified receptors in Dona Ana, Eddy, and Lea counties, New Mexico, and in El Paso County, Texas that are also of interest to the commenter.

The EPA disagrees with the commenter's claim that monitoring sites in Maryland should be identified as receptors based on recent measured data. The EPA responds to a similar comment regarding the Edgewood monitor in Harford County, Maryland in Section 3.4.3.2 (Projecting Future Year DVs Based on Actual Conditions).

The EPA is not making a final determination regarding the treatment of certain monitoring sites in California. See Section IV.G of the preamble.

AQS ID	State	County	2023 Max DV	2023 Max DV – 2021 DV	2023 Max DV – 2022 DV (Preliminary)
40278011	Arizona	Yuma	72.1	5.1	4.1
60650016	California	Riverside	73.1	-4.9	-3.9
60651016	California	Riverside	92.2	-2.8	2.2
80350004	Colorado	Douglas	71.9	-11.1	-11.1
80590006	Colorado	Jefferson	73.5	-7.5	-9.5
80590011	Colorado	Jefferson	74.1	-8.9	-9.9
80690011	Colorado	Larimer	72.1	-4.9	-4.9
90010017	Connecticut	Fairfield	72.2	-6.8	-4.8
90013007	Connecticut	Fairfield	73.8	-7.2	-7.2
90019003	Connecticut	Fairfield	73.6	-6.4	-6.4
90099002	Connecticut	New Haven	72.6	-9.4	-6.4
170310001	Illinois	Cook	71.9	0.9	-0.1
170314201	Illinois	Cook	71.5	-2.5	-2.5
170317002	Illinois	Cook	71.3	-1.7	-2.7
350130021	New Mexico	Dona Ana	72.1	-7.9	-8.9
350130022	New Mexico	Dona Ana	72.4	-2.6	-2.6
350151005	New Mexico	Eddy	74.1	-2.9	-2.9
350250008	New Mexico	Lea	72.2	6.2	6.2
480391004	Texas	Brazoria	72.5	-2.5	-0.5

481210034	Texas	Denton	71.6	-2.4	-4.4
481410037	Texas	El Paso	71.4	-3.6	Missing 2022 DV
481671034	Texas	Galveston	72.8	0.8	2.8
482010024	Texas	Harris	76.7	2.7	7.7
482010055	Texas	Harris	71.9	-5.1	-5.1
482011034	Texas	Harris	71.3	0.3	-0.7
482011035	Texas	Harris	71.3	0.3	-0.7
490110004	Utah	Davis	74.2	-3.8	-4.8
490353006	Utah	Salt Lake	74.2	-1.8	-1.8
490353013	Utah	Salt Lake	73.8	-2.2	-3.2
530330023	Washington	King	71.0	7.0	1.0
550590019	Wisconsin	Kenosha	71.7	-2.3	-3.3
551010020	Wisconsin	Racine	71.5	-1.5	-3.5
551170006	Wisconsin	Sheboygan	73.6	1.6	-1.4

Comment:

Commenter (0344) states that the EGU portion of Indiana's overall ozone impact was modeled by the EPA at 0.37 ppb at the Kenosha - Chiwaukee receptor, while Indiana's non-EGU ozone impact was modeled at 3.03 ppb. Thus, the combined pre-control overall ozone impacts from Indiana's EGU and non-EGU account for 4.7 percent of the overall modeled ozone at Chiwaukee. The difference between the 2023 and 2026 modeled DVs for the Kenosha - Chiwaukee receptor decreased from 72.8 ppb to 71 .7 ppb. Of the 1.1 ppb modeled difference, Indiana's modeled impacts decreased by just 0.17 ppb. If 47,186 tons of NO_X reduction [Note: this was the total amount from all states.] amounts to less than 0.5 ppb ozone improvement at any receptor that Indiana is linked to, and the receptor is not projected to attain the standard, then emissions reductions from other source sectors that account for a larger impact must be targeted. Reducing emissions from source categories that account for less than 5 percent of the total concentration by a fraction does not provide meaningful or cost-effective impacts. Based on the most recent source apportionment modeling conducted by the Lake Michigan Air Director's Consortium, the overall non-EGU impacts for the Kenosha - Chiwaukee receptor were less 7.3 percent, while onroad and nonroad sectors account for nearly 50 percent of the overall ozone concentrations.

Response:

This is essentially an argument against the 4-step interstate transport framework, but it fails to address the logic of the EPA's approach at Step 3 or the EPA's findings with respect to Step 3 in this action. As in prior transport rules, our Step 3 analysis continues to show that obtaining a uniform and reasonable level of emissions control from large stationary sources across the geography of the linked upwind region delivers meaningful air quality benefits to downwind receptors. The basis for the Step 3 approach is discussed in Section V.A and the air quality findings in relation to Step 3 for this rule are set forth in Section V.D.

Comment:

Commenter (0547) states EPA's modeling at Step 1 and Step 2 raise serious concerns regarding the inclusion of Wyoming as an upwind state subject to this rule. The commenter stated that:

- EPA should adequately explain why it concluded certain receptors in California can be removed at Step One based on in-state contributions and cumulative contributions from upwind states.
- EPA should investigate why the modeling results for the Chatfield-Denver receptor is abnormally high relative to the other Denver-area receptors. The outlier results at this single receptor alone result in Wyoming being included as a contributing upwind state.

Response:

As explained in preamble Section IV.F, the Agency is deferring action at this time for Wyoming with respect to its proposed FIP actions for that state.

Comment:

Commenter (0758) states that intensifying wildfire events and more severe wildfire smoke events linked to climate change are influencing the co-occurrence of multiple harmful air pollutants including ozone and fine PM. Another source of underestimation in EPA's ozone projections is underestimated mobile- source emissions for multiple reasons: recent studies have shown that mobile-source NOx emissions performance deteriorates faster than assumed, abundant evidence confirms that tampering with emissions control equipment on vehicles is rampant, EPA's projections do not reflect decreases in fleet turnover rate, and the real-world operational lives of heavy-duty highway engines are now longer than the current useful life mileages in EPA's regulations. Yet another source of underestimation in EPA's ozone projections, which is likely to become more consequential with time, is EPA's failure to account for growing emissions from the burning of fossil fuels to mine cryptocurrencies in its Emissions Inventories.

Response:

The EPA includes wildfires in its projected emissions at the levels at which they occurred in the base year of 2016. We use the 2016 fires in the future year air quality modeling because fires are heavily impacted by meteorological conditions and 2016 meteorology is used in the base year and future year modeling, as described in the Air Quality Modeling TSD for this Final Rule.

Regarding the commenter's claim that mobile source emissions are underestimated in the EPA's projections, the responses to the main points are as follows. On the claim that recent studies have shown that mobile-source NOx emissions performance deteriorates faster than assumed, the cited study[62] uses remote sensing to show that light-duty vehicles emit more NOx as they age. Light-duty vehicle NOx emissions control deterioration is accounted for in EPA's analysis. The MOVES model used to estimate light-duty NOx accounts for emissions deterioration as explained in the EPA report Exhaust Emission Rates for Light-Duty Onroad Vehicles in MOVES3 (PDF)[63]. Regarding the impacts of tampering with emissions control equipment[64], the EPA has found evidence of tampering in diesel pickup trucks and does not yet account for the impacts of tampering in the MOVES model. However, it is not yet clear the degree to which emissions control tampering occurs among gasoline vehicles, or among the long-haul trucks that drive the majority of diesel miles. This uncertainty has been addressed with the recently finalized heavy-duty truck rule, 87 Fed. Reg. 17,414, 17,505-6 (Mar. 28, 2022) and is not of a magnitude that would impact the conclusions reached by the modeling analysis supporting this action. Regarding the increased average age of vehicles in the U.S., fleet turnover is modeled in MOVES using age distributions. While the commenter is correct that year 2022 fleet turnover[65] is lower than that assumed for this analysis, the differences from year to year are relatively small. The source notes an average age of 11.7 years in 2017, the year used as the base for the MOVES age distribution projection, and the "record level" in the cited report is 12 years. In projecting age distributions to future years, the EPA maintains county by county variability in the typical vehicle age such that counties with newer vehicles in the base year also have newer vehicles in the analytic years. We note that the "useful life mileages" in EPA regulations are not the values used when estimating vehicle emissions in

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[62] TRUE Initiative, New Report: Real-world emissions of US vehicles increases with age, says 60m dataset (Oct. 30, 2020), *https://www.trueinitiative.org/blog/2020/october/new-report-real-world-emissions-of-us-vehicles-increase-with-age-says-60m-dataset*.

[63] https://www.epa.gov/system/files/documents/2022-12/420r22032.pdf.

[64] *https://www.epa.gov/sites/default/files/2021-01/documents/epaaedletterreportontampereddieselpickups.pdf*

[65] *With cars in short supply, U.S. drivers are holding onto their vehicles longer than ever*, CBS News (May 23, 2022, 6:34 PM), *https://www.cbsnews.com/news/average-car-age-american-drivers-are-holding-on-to-theirs-longer-than-ever/*

MOVES. Instead, we use real-world mileage and registration data from FHWA as explained in Population and Activity of Onroad Vehicles in MOVES3[66] and in the 2016v3 Emissions Modeling TSD.

The mining of cryptocurrency is one of many demands on the power grid and is currently estimated to account for 0.9 to 1.7 percent of U.S. power demand.[67] Forecasted electricity demand is included in the IPM modeling for this rule. EGUs used for crypto mining are subject to this rule if they meet the applicability criteria for the Group 3 trading program (which is identical to the applicability criteria of prior transport rules).

3.5 Upwind State Contributions Modeling

3.5.1 Approach for Source Apportionment Modeling

Comment:

Commenter (0518) The EPA's use of the Anthropogenic Precursor Culpability Assessment (APCA) probing tool similarly added to overstated upwind state contribution by accounting for ozone formed from both anthropogenic NO_X emissions and biogenic VOC emissions. It is problematic for two reasons: First, had the EPA used a true ozone source apportionment tool, instead of the APCA, biogenic emissions would not have been allocated in this manner. Second, the inclusion of these combined anthropogenic and biogenic emissions raises concerns over potential double-counting of ozone.

Commenters (0509, 0516) state had the EPA considered natural emissions, such as lightning, the corresponding upwind state contribution to downwind receptors would have been reduced. Additionally, the EPA's use of the APCA probing tool similarly added to overstated upwind state contribution by accounting for ozone formed from both anthropogenic NO_X emissions and biogenic VOC emissions. Had the EPA used a true ozone source apportionment tool, instead of the APCA, biogenic emissions would not have been allocated in this manner. Additionally, the inclusion of combined anthropogenic and biogenic emissions raises concerns over potential double-counting of ozone.

Response:

The commenters claims that the Anthropogenic Precursor Culpability Assessment tool (APCA) in the CAMx model, which the EPA used to quantify upwind state contributions to downwind receptors at Step 2 of the 4-step interstate transport framework, is biased toward attributing

[66] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1011TF8.pdf

[67] https://www.whitehouse.gov/ostp/news-updates/2022/09/08/fact-sheet-climate-and-energy-implications-of-crypto-assets-in-the-united-states/#:~:text=The%20United%20States%20is%20estimated,mining%20is%20also%20highly%20mobile.

more ozone to NO_X emissions and, as a result, the EPA has overestimated the potential efficacy of NO_X controls on the (Lake Michigan area) receptors. The EPA notes that the Agency is not defining “significant contribution” at Step 3 for any state covered by this action. To clarify the issue raised by the commenter, however, the EPA notes that the CAMx Ozone Source Apportionment Tool (OSAT) and APCA use the ratio of the production rates of hydrogen peroxide and nitric acid as the indicator to classify ozone formation as being limited by NO_X or VOC. This ratio is used in OSAT to assign ozone production to sources of NO_X versus sources of VOC depending on the magnitude of this ratio. Ozone formation is classified as being NO_X-limited when the ratio is less than the 0.35 and VOC limited when the ratio is above this threshold.[68] As stated in the CAMx User’s Guide, the APCA tool operates similar to OSAT, except that APCA recognizes that biogenic emissions categories are not controllable and that apportioning ozone production to this category does not provide information that is relevant to development of control strategies. To address this, in situations where OSAT would attribute ozone production to non-controllable biogenic emissions, APCA re-allocates that ozone production to the controllable precursors that participated in ozone formation with the non-controllable precursor. For example, when ozone formation is due to biogenic VOC and anthropogenic NO_X under VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NO_X present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NO_X sources and less ozone formation attributed to biogenic VOC sources.[69]

Considering the construct and purpose of APCA, as stated by the model developers, the EPA does not agree with the comment that using APCA overstates the efficacy of NO_X controls. *See also Wisconsin*, 938 F.3d at 323-24 (upholding use of APCA approach to apportionment).

The EPA disagrees with commenter’s claim that had the EPA considered natural emissions, such as lightning, the corresponding upwind state contribution to downwind receptors would have been reduced. First, the commenter does not provide any information to support their contention. Second, as described in the 2016v2 and 2016v3 Emissions Modeling TSDs, used for the proposed and final rules, respectively, the EPA includes emissions from biogenic sources in its air quality modeling. Moreover, in response to comments, the EPA has added NOx emissions from lightning in the air quality modeling for this final rule.

Comment:

Commenter (0509) specifies, if naturally occurring NOx emissions from lightning as well as methane emissions were included in the EPA's proposed rule CAMx modeling from the

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

[69] Ramboll Environ, 2021. User's Guide Comprehensive Air Quality Model with Extensions version 7.1, www.camx.com. Ramboll Environ International Corporation, Novato, CA.

Denver- Julesburg Basin that lies between the Chatfield receptor, it would reduce Wyoming contributions to the 2023 and 2026 ozone DVs at Chatfield.

Commenter (0509) specifies, if naturally occurring NOx emissions from lightning were included in the EPA's Proposed Transport Rule CAMx modeling, then the EPA would have determined that Wyoming's contributions to the 2023 and 2026 ozone DVs at Chatfield would be lower.

Commenter (0509) also argues that the EPA did not map CMAQ methane (CH_4) to the CAMx ECH4 species, that some researchers believe that methane emissions are already understated in emissions inventories, and that, as a result, the EPA overestimated Wyoming's contributions at Chatfield.

Response:

The commenter did not provide any information or data to support the claim that including NOx emissions from lightning strikes would reduce contributions from Wyoming to the Chatfield receptor in Denver. Although the EPA is not taking final action on the proposed FIP for Wyoming at this time, the EPA is responding to the general criticisms of the EPA's emissions inventories and modeling raised by this comment. In response to this issue of lightning raised by commenters, the EPA included NO_X emissions from lightning strikes in the 2016v3 emissions inventory used for the air quality modeling of this final action. The method for including these emissions in the modeling are described in 2016v3 Emissions Modeling TSD, available in the docket and at https://www.epa.gov/air-emissions-modeling/2016v3-platform.

The EPA disagrees with the commenter's claim that including methane emissions from oil and gas production in the Denver- Julesburg Basin would decrease the contribution from Wyoming. First, the comment is speculative. The commenter provided no analyses or data, to support their hypothesis that including a higher amount of global background methane by 6 percent or adding methane emissions in EPA's modeling would have increased model predicted ozone concentrations in the Denver area or decreased ozone contributions from Utah or Wyoming to those receptors. Furthermore, the commenter is focused on the contribution to local ozone production of methane emissions from oil and gas production in Colorado but fails to consider the contributions from methane emissions from oil and gas production in both Utah and Wyoming. Following the commenter's logic, adding methane emissions in the EPA's modeling would *increase*, not decrease the contributions from these two states to receptors in Denver.

We note that the ozone source apportionment tools in the latest version of CAMx are not designed to include methane emissions. While methane emissions play a role in the formation of ozone, the model currently accounts for this through functions establishing background levels of ozone, given the slower, longer-term, and larger distances over which ozone from methane emissions is formed.

Comment:

Commenter (0398) claims the EPA was not afforded the time necessary to perform a sufficiently robust determination through modeling because of the consent decree timeline. This is why the agency performed base modeling and used scaling at a statewide level to determine the "effect" of their proposed control strategy on upwind monitors. However, according to the commenter, a restrictive deadline is no excuse for performing conventionally inept technical analysis (*e.g.*, without QA/QC data, riddled with unchecked assumptions, etc.) to support such an economically aggressive proposal. Because of the immense scope of the proposed FIP, this is precisely the time EPA should have doubled-down on supporting analysis and documentation to be sure the proposal that was produced is defensible through sound science and by reliable reasoning. In its present form, the proposed FIP offers neither of these, and the proposed controls in the FIP are therefore indefensible and unreasonable. To properly correct these deficiencies, the commenter suggests that the EPA must perform new modeling that takes into account state corrections and the EPA should perform a more robust source-apportionment analysis. The EPA must also release a NODA when the modeling results are available to allow states to evaluate the impact of sources or sectors from within the state on linked downwind monitors and whether the control strategies proposed by the EPA are appropriate based on the corrected inventory projections and source/sector contributions (based on source-apportionment) from within the state to downwind linked monitors.

Response:

The EPA finds that the 2016v2 was sufficiently robust to support the proposed rulemaking. In response to this comment and other similar comments, the EPA performed updated modeling using the 2016v3 emissions platform which reflects comments and corrections on the emissions and air quality modeling in the proposed rule. The EPA is even more confident in the technical merits of the 2016v3 modeling.

The EPA addresses comments related to consent decrees in Section 1.11.3.6 (Role of Consent Decrees). The EPA addresses other procedural comments in Section 10.1 (Complaints About Not Having Long Enough Comment Period).

Comments:

Commenter (0436) states there appears to be a proportional discrepancy in the identified emissions reductions relative to a state's downwind contribution. As an example, the commenter notes that California's contribution to Utah's Northern Wasatch Front's (NWF) nonattainment area was identified as 2.5 ppb and California will be required to reduce 1,666 tons of NO_X emissions, while at the same time, Utah's contribution to Colorado's Denver Metro nonattainment area is 1.3 ppb but is being required to reduce 7,816 tons of NO_X, a 4.7 times greater emissions reduction than that required of California despite Utah's substantially smaller contribution to downwind areas. This disconnect implies that the sources selected for emissions reductions were selected based on criteria other than ozone transport alone.

Commenter (0398) The EPA performed no higher resolution source-apportionment analysis beyond tagging statewide emissions to identify individual significant contributors. The EPA instead used anecdotal data from other states regarding source types impacting non-attainment receptors and then broadly applied these source-specific impacts to broad sectors to develop their control strategy. This does not provide adequate reasoning to apply costly controls with such a broad brush. The EPA proposes the same level of categorical control for all fossil-fuel fired EGUs, and Tier 1 and Tier 2 non-EGU NO_X sources in all upwind states that are linked to non-attainment downwind monitors, no matter the magnitude of effect, and without an analysis of which sources are significantly contributing to these monitors.

Commenter (0782) notes the EPA should perform source-apportionment modeling to determine which EGU sources significantly impact downwind receptors. The EPA uses "source apportionment" modeling to show impacts of emissions from Wyoming on Colorado. However, the EPA groups all emissions from all sources from Wyoming together and makes no attempt to apportion impacts from particular sources to specific monitors in Colorado. It is possible that just one large unit in Colorado or Wyoming slated for retirement could be impacting the Douglas County monitor. Yet the EPA arbitrarily and unreasonably imposes onerous and expensive requirements on the entire state of Wyoming and virtually all EGUs and non-EGUs in the state. Source apportionment in Wyoming and Colorado is particularly important because the EPA failed to consider all source retirements and conversions scheduled to occur in the same time period as the Proposal. If the EPA' s modeling "tagged" the emissions from future retirements or other large units, it could significantly streamline the Proposal by only requiring the largest or most significant contributors to the nonattainment of the Douglas County monitor be addressed. And to the extent facilities slated for retirement are the cause of the state's contribution to nonattainment, that would nullify the need for the EPA to expand the NO_X trading program to other Wyoming sources and impose costly requirements on other units. The EPA is grouping all units from Wyoming together without adequately demonstrating which units significantly contribute to nonattainment issues in Colorado.

Response:

In response to comments suggesting the EPA assess state-level reductions proportional to each state’s degree of ppb contribution to downwind receptors, as explained in Section V.D. of the preamble, the EPA is using the same Step 3 approach used in all prior CSAPR Rules which is informed by a uniform cost and mitigation strategy for linked states. While cost is a consideration in its Step 3 analysis, it is not a singular determinative factor. In other words, the EPA is not identifying a $/ppb or $/ton level and then identifying each reduction below that level on a unit-level basis. Rather, the EPA is evaluating uniform control strategies for linked states (characterized by a representative cost) and assessing the reductions, air quality impact, and uniform representative cost in a multi-factor test. See preamble Section III.B and Section V for further discussion. The EPA’s analysis in Section V of preamble 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.

3.5.2 Method for Calculating Contributions

Comment:

Commenter (0758) notes the EPA irrationally omits numerous monitors from its contribution analysis, with significant implications for its proposed transport rule. The EPA's 2023 and 2026 ozone DV projection analysis includes 941 monitors. However, its contribution analysis includes only 397 monitors. The EPA's exclusion of nearly 550 monitors, some of which are projected to be nonattainment monitors creates a significant risk of missing linkages that could affect the scope of the rule. The EPA must update its contribution analysis to include, at minimum, all monitors for which the average or maximum 2023 or 2026 DV, is above the 70 ppb standard.

Commenter (0758) claims the EPA excluded from its contribution analysis only those monitors where the EPA projected that fewer than 5 days in 2023 would have an 8-hr daily maximum ozone concentration above 60 ppb—10 ppb below the 70 ppb ozone standard. While this approach appears conservatively inclusive, it was either misapplied by the EPA or its application nevertheless missed numerous monitors that should have been included in the contribution analysis. Rather than attempt to redo the analysis using this 5-day criterion, the EPA should instead use an approach that ensures that all monitors with projected average or maximum DVs exceeding 70 ppb in 2023 or 2026 are included in the contribution analysis.

Commenter (0758) explains that the EPA's focus on the 5th highest day is irrational, as it does not ensure that all monitors exceeding the 70 ppb NAAQS are included in the EPA's contribution modeling. DVs are based on a three-year average of 4th highest ozone days. The 5th highest day has no relevance to calculation of DVs. Moreover, as discussed further below, the EPA's explanation for its excluded monitors is insufficient or implausible as an explanation for many of the missing monitors. Indeed, the EPA omitted from its contribution modeling numerous monitors that are presently designated nonattainment with 2018-2020 DVs exceeding the 70 ppb NAAQS, as well as for numerous monitors with 2018-2020 DVs exceeding the 70 ppb standard that are not in areas presently designated nonattainment. There are at least 55 monitors with 2018-2020 DVs of 71 ppb or higher that were not included in the EPA's contribution modeling. Commenter (0758) believes the EPA must remedy this serious modeling deficiency and must update its contribution analysis to ensure that all monitors with 2023 or 2026 DVs above 70 ppb are included.

Response:

The EPA followed the approach recommended in the EPA's modeling guidance to project 2016-centered average and maximum ozone DVs to 2023 and 2026. There were 1,194 monitoring sites within the continental U.S. with valid 2016 base period DVs. In the EPA's modeling for this final rule, there are projected DVs for 92 percent of these monitoring sites. Of those sites without projected DVs, only one monitoring site (530050003 in Benton County, Washington) had a 2016-centered maximum DV that exceeded the NAAQS. All of the other monitoring sites for which we did not project future year DVs had measured DVs below the NAAQS in the 2016 base period. Moreover, of the 188 monitoring sites with measured 2021 DVs above the NAAQS, the EPA's modeling provides projected DVs and contributions for the vast majority of these sites (*i.e.*, 183 of the 188). In addition, in the final rule modeling there are projected 2023 contributions for all but one of the modeling-based receptors (the maintenance-only monitoring site 530330023 in King County, Washington which has a projected 2023 maximum DV of 71 ppb, but a 2021 measured DV of only 64 ppb).

The EPA disagrees with commenter's claim that the EPA's method for projecting DVs and calculating contributions focuses on the 5th highest day. As recommended in the EPA's modeling guidance, base period DVs are projected to the future using Relative Response Factors (RRFs) which are based on the fractional change in model-predicted ozone concentrations between the base year and the future year modeling. The RRF is calculated using the average ozone concentration for the days with the top 10 highest ozone concentrations in the base year. The EPA's guidance recommends not calculating RRFs for those monitoring sites where there are fewer than 5 days with base year model concentrations greater than or equal to 60 ppb. The approach for calculating the average contribution metric used in Step 2 of the 4-step interstate transport framework, follows the same logic in terms of requiring that there are at least five days with future year modeled concentrations to calculate Relative Contribution Factors (RCFs) that are representative of contributions on days with high concentrations. Contrary to commenter's claims, the absolute model-predicted ozone concentration or contribution on the 5th highest modeled day or any other single day is not the basis for projecting DVs or calculating contributions. Additional information on the EPA's approach for projecting DVs and calculating contributions can be found in the Air Quality Modeling Final Rule TSD.

Comment:

Commenter (0433) states the EPA uses the average state contributions from the top ten modeled ozone days with 8-hour daily maximum averages above 60 ppb to establish significant contribution linkages. However, the form of the ozone NAAQS is the 3-year average of the 4th annual maximum daily 8-hour average. Assessing linkages based on average contributions across ten high ozone days can dilute upwind impacts on the days that are most relevant to a NAAQS violation. For example, the weather patterns conducive to high ozone transport on the four highest days may differ substantially from the conditions on other days within the ten days, resulting in the high upwind contributions on the worst days "washing out" in the average across all ten modeled days. The commenter suggests using the existing EPA-state modeling collaborative group to review and assess potential contribution techniques for future application.

Commenter (0758) summarizes that the EPA should align its Step 2 approach with the form of the ozone standard and ensure that all downwind receptors with nonattainment and maintenance concerns are fully evaluated. Specifically, the commenter urges EPA to adopt an approach where any upwind state that contributes at least 1 percent of the NAAQS to a nonattainment or maintenance receptor on any day when that receptor's modeled 8-hour daily maximum value exceeds the NAAQS be subject to the requirements of the rule.

Commenter (0318) supports the use of photochemical grid modeling as an important tool in assessing linkages between upwind emissions sources and downwind ozone nonattainment and maintenance problem areas. The commenter notes in past communications with the EPA that its methodology for determining if a linkage exists is conservative, *i.e.*, less prone to establish a linkage. The EPA uses the average state contributions from the top ten modeled ozone days with 8-hr daily maximum averages above 60 ppb to establish significant contribution linkages. However, the form of the ozone NAAQS is the 3-year average of the 4th annual maximum daily 8-hr average. Assessing linkages based on average contributions across ten high ozone days can dilute upwind impacts on the days that are most relevant to a NAAQS violation. As an example, the commenter states that the weather patterns conducive to high ozone transport on the four highest days may differ substantially from the conditions on other days within the ten days, resulting in the high upwind contributions on the worst days “washing out” in the average across all ten modeled days. The commenter shares an example of an approach with the EPA in February 2022 where the top four state contributions during modeled high ozone days are averaged, which the commenter believes would improve on the current technique of identifying linkages. The commenter suggests using the existing EPA-state modeling collaborative group to review and assess potential contribution techniques for future application.

Commenter (0328) supports EPA’s use of the average of the 10 highest modeled exceedances for determining each upwind state’s contribution to each receptor in downwind states. While other commentators may favor a modeled 4th highest exceedances approach in determining contribution, the commenter believes that the use of that approach can concentrate ozone impacts based upon one type of meteorological scenario. The commenter states that the 4th highest modeled exceedances approach could cause an overestimation of ozone contributions as actual meteorology often differs from the modeled meteorology.

Response:

Some commenters suggested that the EPA should calculate the multi-day average contribution metric based on model predicted contributions and concentrations on the top 4 concentration days while another commenter offered that the EPA should evaluate an upwind state’s contribution based on the maximum contribution on days with model-predicted exceedances. A third commenter supports the EPA’s methodology. As explained in the Air Quality Modeling Proposed Rule TSD, as well as the Air Quality Modeling Final Rule TSD, the EPA’s methodology for calculating contributions is based on the average of daily contributions on the days with the top 10 model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in the future year modeling. If there are fewer than 10 modeled days that meet this criterion for the given receptor, then the average contribution is calculated based on the remaining days greater than or equal to 60 ppb, provided that there are at least five days with modeled MDA8 values greater than or equal to 60 ppb. Average contribution metric values are not calculated for a receptor if there are fewer than 5 days with future year modeled MDA8 ozone concentrations at or above this threshold.

The basis for using the average contribution as the metric for evaluating upwind state contributions with respect to the 0.70 ppb screening threshold and the basis for requiring a minimum of 5 days with MDA8 ozone concentrations for calculating the average contribution metric is that the magnitude of contributions from upwind states can have very large day-to-day variability. The variability in contributions is the result of different multi-day transport wind patterns combined with the relative proximity of the upwind state to the downwind receptor. Ignoring contributions on all but the top four concentration days when calculating the average contribution metric risks failing to link upwind states which make large contributions on other high ozone days that are not necessarily among the top 4 days. In contrast, limiting the evaluation contributions to the single day with the highest contribution risks linking an upwind state that is not, on balance, a meaningful part of the upwind collective contribution and should, therefore, not be subject to emissions reductions as part of this final rule.

Comment:

Commenter (0547) questions why, unlike the Relative Response Factors (RRF) analysis, in this rulemaking, the EPA uses the top 10 modeled high days in 2023 for day selection—as opposed to the top 10 modeled high days in 2016 for day selection in its RCF analysis. The EPA's modeling guidance does not explain the agency's reasoning for using modeled high days in 2023 in this instance. (see *e.g.*, Air Quality Modeling Proposed Rule TSD at 21). Commenter (0547) asked an agency to follow EPA's process for determining ozone contributions but used the top 10 modeled high days in 2016 to determine the RCF in 2023 and 2026, as well as Wyoming's overall predicted contribution amount based on the RCF. The commenter believes relying on these days, as opposed to the top 10 modeled days in 2023, resulted in Wyoming's contribution levels falling below the 1 percent threshold. Commenter (0547) argues EPA must adequately explain and defend its choice of relying on 2023 modeled high days, as opposed to 2016 modeled high days. The EPA's day selection is critically important, as Wyoming is unlinked from the Denver-Chatfield receptor in 2026 and 2023 when 2016 modeled high days are used—like they were used in the RRF calculation.

Commenter (0509) states an analysis of Wyoming's contribution under EPA's previous methodologies demonstrates that Wyoming's contribution falls under the 1 percent of the NAAQS significance threshold. Of the nine ozone contribution metrics commenter (0509) analyzed, eight demonstrated that Wyoming's ozone contribution to Chatfield is less than 1 percent of the NAAQS significance threshold. The only ozone contribution metric that resulted in a value above the significance threshold was EPA's arbitrary ozone contribution metric.

Response:

In the contribution analysis at Step 2, the EPA uses the modeled concentrations and modeled contributions for the future year to derive a RCF based on the *modeled* 2023 future year (not the 2016 modeled data). The RCF is calculated as the ratio of the 2023 average contribution to the 2023 average ozone concentration, where the averages are based on the top 10 ozone concentration days in 2023. It is important to note that the top 10 concentration days in 2023 may not be the same as the top 10 concentration days in the 2016 base year modeling. Because the average contribution metric is intended to reflect upwind state impacts in 2023, it would be illogical to base that average value in 2023 on model predictions for the 2016 base year, seven years earlier. The RCF is then applied to the projected 2023 average DV to apportion the 2023 DV to individual states and other source categories tracked in the contribution modeling as described in the Air Quality Modeling Final Rule TSD.

Step 2 analysis starts from the premise that downwind receptors have already been properly identified using the methodology at Step 1. At Step 2, the question is who is contributing to those receptors, for which EPA's methodology provides a reliable answer using modeling and the RCF approach. As noted above, the approach for selecting days to calculate the contribution metric is designed to align with recommendations in the EPA's modeling guidance for projecting future year DVs. Following the selection of days, the approach for calculating the average contribution metric then determines what proportion of the ozone formed on those days, on average, was attributable to emissions from each upwind state or other source.

The table below provides the modeled MDA8 ozone concentrations at the receptor in Sheboygan, Wisconsin for the top 10 days greater than or equal to 60 ppb in 2016 and 2023 along with the ranking of each day in each year. At this receptor there are 10 days greater than or equal ot 60 ppb in 2016, but only 9 days that meet this criterion in 2023. In total, 8 of the top 10 days in 2016 are also among the highest days in 2023. However, two of the top 10 days in 2016 are predicted to be below 60 ppb in 2023. One of the days greater than 60 ppb in 2023 was not among the top 10 in 2016. In this case, relying upon the top 10 days in 2016 would result in calculating the average contribution metric using daily contributions for two days (*i.e.*, 05/25 and 08/11) that are below the 60 ppb criterion in 2023 while excluding data for one of the top days in 2023.

Table 3-20

Date	**Rank Based on 2016**	**2016 MDA8 O3**	**Rank Based on 2023**	**2023 MDA8 O3**
08/04	**1**	84.5	**1**	75.2
07/20	**2**	78.9	**2**	72.0
06/25	**3**	76.9	**3**	69.9
07/11	**4**	75.9	**5**	67.9
06/15	**5**	75.4	**4**	68.3
06/19	**6**	72.6	**6**	64.8
06/10	**7**	68.6	**7**	62.4
08/18	**8**	64.1	**9**	60.0
05/25	**9**	63.3	**-**	57.9
08/11	**10**	62.3	**-**	57.9
05/24	**-**	62.1	**8**	60.1

Regarding the commenters claims about the contributions from Wyoming to the Denver/Chatfield receptor, the EPA first notes that the EPA is deferring action related to Wyoming at this time. However, as a sensitivity analysis the EPA recalculated the average contribution metric for Wyoming at this receptor based using the 2023 contributions on the top 10 days in 2016. The table below provides the 2016 and 2023 modeled MDA8 ozone concentrations at the Denver/Chatfield monitoring site (080350004) and the daily 8-hour average contributions to this receptor from Wyoming based on the EPA's 2016v3 modeling that is used for this final rule. At this receptor, 7 of the top 10 days in 2023 are also among the top 10 days in 2016. The remaining three days that comprise the top 10 are different days in 2016 versus 2023. In this instance, the contributions from Wyoming are higher, overall, on the remaining three days in 2016 compared to three days in 2023. Applying the EPA's contribution calculation method to these data results in an average contribution metric value for Wyoming to this receptor of 0.68 ppb (*i.e.*, below the 1 percent of the NAAQS screening threshold) using data for the top 10 days in 2023, whereas the contribution from Wyoming to this receptor is 0.87 ppb (*i.e.*, above the screening threshold) using data on the top 10 days in 2016. As stated above, the EPA continues to believe that contributions on high ozone days in 2023 are most relevant for calculating the average contribution metric for 2023.

Table 3-21

	Date	2016 MDA8 Ozone	2023 MDA8 Ozone	Wyoming Contribution
Days in Top 10 in both 2016 and 2023	*08/03*	83.5	76.3	1.00
	07/27	77.5	74.2	0.81
	07/16	76.8	71.6	0.05
	08/12	76.8	70.6	0.57
	06/19	76.6	70.8	0.00
	06/29	74.1	70.8	0.88
	06/17	74.0	69.2	2.04
Days in Top 10 in 2016, but not 2023	*06/09*	74.2	67.0	1.87
	07/17	73.6	68.5	1.05
	06/26	73.3	66.9	0.36
Days in Top 10 in 2023, but not 2016	*07/18*	71.0	69.4	0.02
	08/11	70.9	68.7	0.08
	07/28	69.9	68.7	1.29

Comments:

Commenter (0323) cites the Alpine Geophysics, LLC report that merged the onroad emissions data with a 2028 “base case” modeling simulation. This work assesses how the change in mobile source emissions between a 2028 base case and the CTI scenario would change the ozone and $PM_{2.5}$ ambient air quality projections at receptors in the continental United States. The modeled 2028 base year 8-hr ozone DVs were found to be above the 70 ppb NAAQS in the states of California, Utah, Colorado, Texas and Connecticut. Applying the 90 percent NO_X emissions reduction CTI scenario to a 2028 base year eliminates ozone nonattainment everywhere east of the Rockies and in Denver and leaves only the states of California and Utah with 70 ppb 2015 ozone NAAQS nonattainment areas. Multiple monitors in California and in Salt Lake County, Utah also show modeled attainment with the CTI strategy. The greatest ozone impact of the strategy is seen in urban areas and along highway corridors with reductions of up to 6.5 ppb seen in the west (San Bernardino) and 4.9 ppb seen in the east

(Atlanta). The commenter provides details on the CTI strategy impacts on the annual $PM_{2.5}$ DV nationwide with modeled attainment changes occurring at monitors in Madera, San Joaquin, and Stanislaus counties in California. The greatest annual $PM_{2.5}$ impacts are reductions of 0.64 $\mu g/m^3$ (4.1 percent) seen in the west (Kern County, CA) and 0.21 $\mu g/m^3$ (2.3 percent) reduction in the east (Chicago). As with the annual $PM_{2.5}$ modeling, areas shown to move to modeled attainment as a result of the CTI strategy include Madera, Merced, and San Joaquin counties in California. The greatest daily $PM_{2.5}$ impacts are reductions of 4.5 $\mu g/m^3$ (9.8 percent) seen in the west (Tulare County, CA) and 0.9 $\mu g/m^3$ (4.5 percent) reduction in the east (Chicago).

Commenter (0323) concludes this illustrates the need for measurable improvements to environmental conditions in communities that are heavily impacted by dense traffic. Commenter states that ambient improvements to $PM_{2.5}$ and ozone represented by this proposed rule will serve to facilitate the development of implementation outcomes of local environmental benefits attributable to controls on mobile sources like heavy duty trucks. EPA's burden is to effectively implement mobile source controls per Executive Order 12898, "Federal agencies must identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations." Given the technical availability and cost effectiveness of achieving a 90 percent reduction of NO_X emissions from heavy duty trucks by 2035 as established by MECA and by 2045 as demonstrated by the EPA and given the remarkable improvement in air quality as demonstrated by the Alpine and EPA modeling, commenter (0323) urges that the EPA work to effectively and timely regulation to achieve the 90 percent reduction in NO_X emissions from heavy duty trucks.

Response:

We understand the commenter to be arguing that ozone levels might be lower and thus interstate-transport receptors may resolve in 2028 or later years, if the EPA were to promulgate more stringent vehicle emissions standards. The levels of NO_X emissions reduction cited by commenter are speculative and not associated with any final EPA rule. Further, we did not model 2028 using the 2016v2 or 2016v3 platforms, nor is 2028 a relevant analytic year for this action, falling five years beyond the 2023 analytic year associated with the Moderate area attainment date and two years after the 2026 analytic year. We recognize that mobile sources are important contributors to emissions of criteria pollutants and greenhouse gasses. The EPA has finalized a rulemaking to reduce emissions of several air pollutants, including NO_X, from heavy-duty vehicles and engines starting in model year 2027.[70] The rule is consistent with President Biden's Executive Order 14037, "Strengthening American Leadership in Clean Cars

[70] On December 20, 2022, the EPA finalized more stringent emissions standards for NO_X and other pollutants from heavy-duty vehicles and engines, beginning with model year 2027. *See https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-and-related-materials-control-air-pollution*. The EPA is also developing new multi-pollutant standards for light- and medium-duty vehicles as well as options to address pollution from locomotives.

and Trucks,"[71] and helps ensure that the heavy-duty vehicles and engines that drive American commerce are as clean as possible while charting a path to advance zero-emissions vehicles in the heavy-duty fleet. The Final Rule for control of air pollution from heavy-duty engine and vehicle standards targets emissions reductions beginning in the year 2027. Therefore, these emissions reductions will not begin to take place until after the relevant analytic years used in this action and is therefore not included in the modeling for this action.

3.5.3 Contributions from States, International, and Other Sources

3.5.3.1 New Mexico

Comment:

Commenter (0758) states that the EPA arbitrarily omitted relevant El Paso County monitors and thus erroneously excludes Arizona and New Mexico from the proposal. El Paso County, Texas, has six ozone monitors, and routinely records elevated ozone levels. In 2020 three of the monitors recorded DVs exceeding the 70 ppb ozone standard, and in 2021, two monitors continued to record DVs of 71 ppb or higher, including one monitor (the University of Texas at El Paso Monitor, No. 481410037) with a DV of 75 ppb. The Agency characterized the University of Texas at El Paso monitor as a "maintenance" monitor, with a max 2023 "no water" DV of 71.3 ppb. In its contribution modeling, however, the EPA inexplicably omitted this monitor. The omission of the El Paso maintenance monitor has significant implications for the EPA's transport rule. The EPA's contribution spreadsheet shows that Arizona contributes well above the 1 percent contribution threshold to the two El Paso monitors that the EPA did include (1.66 ppb contribution to the Ivanhoe monitor 481410029 and 1.27 ppb contribution to the Skyline Park monitor 481410058). Similarly, New Mexico contributes well in excess of the 1 percent contribution threshold to the two El Paso monitors that the EPA included in its contribution spreadsheet (contributing 1.52 ppb to Ivanhoe and 1.67 ppb to Skyline Park).

Commenter (0758) notes the EPA also omitted relevant Dona Ana County monitors and thus erroneously excludes Arizona from the proposal. Dona Ana County, New Mexico has five ozone monitors. Based on both 2018-2020 and 2019-2021 DVs, three of the five monitors violate the 2015 ozone NAAQS. The EPA projects the "no water" max for Desert View to be 72.2 ppb in 2023 and 71.7 ppb in 2026. And the EPA projects the "no water" max for Santa Teresa to be 72.1 ppb in 2023 and 71.6 ppb in 2026. The EPA excluded monitors Desert View and Santa Teresa from its contribution spreadsheet. That is, the EPA provided no modeling of which states contribute to the elevated ozone levels at these monitors for 2023 or 2026.

Response:

As described in the preamble and Air Quality Modeling Final Rule TSD, the EPA performed updated modeling using the 2016v3 platform to identify receptors and evaluate interstate contributions for this final rule. Based on this updated modeling New Mexico contributes

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[71] 86 FR 43583 (August 10, 2021).

above the 1 percent of the NAAQS contribution screening threshold to a maintenance-only receptor in El Paso, Texas and Arizona contributes above this screening threshold to El Paso, Texas receptor as well as receptors in Dona Ana, Eddy, and Lea counties, New Mexico and in Larimer County, Colorado. The EPA's intent regarding Arizona and New Mexico is in the preamble in Section I.A.

3.5.3.2 National Parks

Comment:

Commenter (0758)

The EPA should give full consideration to, and include in its contribution modeling, receptor sites in or near National Parks and other protected lands. Public lands visitation is on the upswing as outdoor recreation increased during the pandemic. Yet National Parks are experiencing too many ozone exceedances due to pollution transport. The map below shows the number of exceedance days in 2021 at National Parks across the U.S. It is well documented that Eastern United States parks and beaches see long-range transport from areas in the Eastern United States and sea breeze remixing. The EPA has also identified interstate transport between the western states of Arizona, California, Nevada, Oregon, Utah, and Wyoming.

Response:

The EPA has considered all monitoring sites nationwide in its analysis of interstate transport. In Step 1 the EPA projected 2016 base period average and maximum DV to 2023. In total there were 1194 monitoring sites with valid base period DVs that could be projected to 2023. As recommended in the EPA's modeling guidance, 2016 modeled ozone concentrations were examined to identify those monitoring sites for which there were at least 5 days with model predicted MDA8 ozone concentration of 60 ppb or higher. Projected 2023 DVs are calculated for those monitoring sites that meet this criterion. That is, as recommended in the EPA's modeling, projected DVs are not calculated for those monitoring sites for which there are fewer than 5 days with MDA8 concentrations at or above 60 ppb. As a result of applying this criterion, we project 2023 DVs for 92 percent of the monitoring sites with valid base period measured data. This includes 112 monitoring sites in National Parks or at other regional background sites reported as part of the Clean Air Status and Trends Network (CASTNET).

3.5.3.3 Denver

Comment:

Commenter (0240) states that historically, there have been four monitors in the DM/Northern Front Range (NFR) nonattainment area that have driven the area's DVs (DV) - Chatfield, NREL, Rocky Flats North, and Fort Collins West. The commenter provides that recent source apportionment modeling looking at the future year of 2023 has demonstrated that on a typical high ozone day background ozone and ozone transported into the region accounts for 69 percent - 78 percent of the ozone being modeled at the monitor. The commenter notes that additional modeling was conducted to provide a more refined look at the origin point of ozone being transported into the DM/NFR nonattainment model. According to the commenter, this modeling demonstrates that on typical high ozone days in the DM/NFR, a significant level of anthropogenic emissions from California, Utah, and Wyoming are contributing to ozone levels in the DM/NFR nonattainment area. The commenter states that reducing emissions from sources in these states, coupled with local emissions reduction measures that are scheduled to occur, will directly reduce ozone levels across the DM/NFR nonattainment area as demonstrated by the 2023 Transport modeling analyses conducted by the RAQC. These reductions are necessary for the region to attain the 8-hour ozone NAAQS as expeditiously as possible.

Response:

As explained in Section IV.F of the preamble, the EPA is deferring action at this time for Wyoming.

Comment:

Commenter (0554) states western states (Nevada, Utah and Wyoming) should be excluded from the final rule due to their de minimis impact. Nevada's own modeling in support of its good neighbor SIP, which was based on the EPA modeling available at the time of the submittal, showed that Nevada emissions sources contribute only 0.9 percent of the NAAQS to any nonattainment or maintenance receptors. This discrepancy, based on two different models, is evidence that a slight change in assumptions will bring Nevada's impacts below EPA's 1 percent threshold. With Nevada being so close to the threshold for inclusion in the rule, the Proposed Rule is likely to overcontrol the state, since it will likely result in greater emissions reductions than the EPA has assumed in its modeling.

Response:

The EPA is deferring final action on Wyoming at this time.

The EPA disagrees Utah has a de minimis impact. The EPA is finding that Utah is linked above 1 percent of the NAAQS to one or more downwind receptors. Utah is also linked above 1 ppb in both 2023 and 2026 (see Table IV.F-1 and IV.F-2 in the preamble).

The EPA disagrees with the commenter's assertion that a slight change in assumptions will bring Nevada's contribution to below the 1 percent of the NAAQS screening threshold. The data in the top table below shows that Nevada is linked to three receptors in Salt Lake City in 2023 based the EPA's 2016v3 modeling used for this final rule (*i.e.*, Bountiful Viewmont, Hawthorne, and Herriman). At two of these receptors (*i.e.*, Bountiful Viewmont and Hawthorne) Nevada contributes more than 1 ppb. In the 2016v2 modeling used for the proposal rule Nevada was linked to two of the three receptors (Bountiful Viewmont and Hawthorne). The second table below shows the contributions from Nevada to Bountiful Viewmont and Hawthorne in the 2011-based modeling platform that the EPA released in March 2018 and that Nevada relied on for its good neighbor SIP. The contributions from Nevada to these two monitoring in the 2011-based platform are similar in magnitude to the 2016v3-based contributions, despite that fact that these two sets of modeling (*i.e.*, 2011-based and 2016-based) relied on meteorology from different years and different base year and 2023 projected emissions. Comparing the 2011-centered average and maximum DVs to the corresponding 2016-centered data indicates that measured concentrations increased to the extent that the projected average and maximum 2023 DVs using the 2016-based platform are above the NAAQS, whereas the projected 2023 DVs from the 2011-based platform were below the NAAQS at these two sites. These results indicate that the 2016-based modeling is robust with respect to Nevada's linkage to downwind receptors.

				Proposed Rule 2016v2 Modeling			Final Rule 2016v3 Modeling		
AQS Site ID	**Location**	**2016 Centered Avg DV**	**2016 Centered Max DV**	**2023 Avg DV**	**2023 Max DV**	**Nevada Contribution**	**2023 Avg DV**	**2023 Max DV**	**Nevada Contribution**
490110004	Bountiful Viewmont	75.7	78	72.9	75.1	0.86	72.0	74.2	1.00
490353006	Hawthorne	76.3	78	73.6	75.3	0.89	72.6	74.2	1.11
490353013	Herriman	76.5	77	74.4	74.9	0.63	73.3	73.8	0.77

		2011 Platform Modeling				
AQS Site ID	**Location**	**2011 Centered Avg DV**	**2011 Centered Max DV**	**2023 Avg DV**	**2023 Max DV**	**Nevada Contribution**
490110004	Bountiful Viewmont	69.3	71	60.0	61.5	0.92
490353006	Hawthorne	76.0	76	65.8	65.8	1.09
490353013	Herriman	***No Measured DVs at this Monitor Prior to 2017***				

3.5.3.4 Arkansas

Comment:

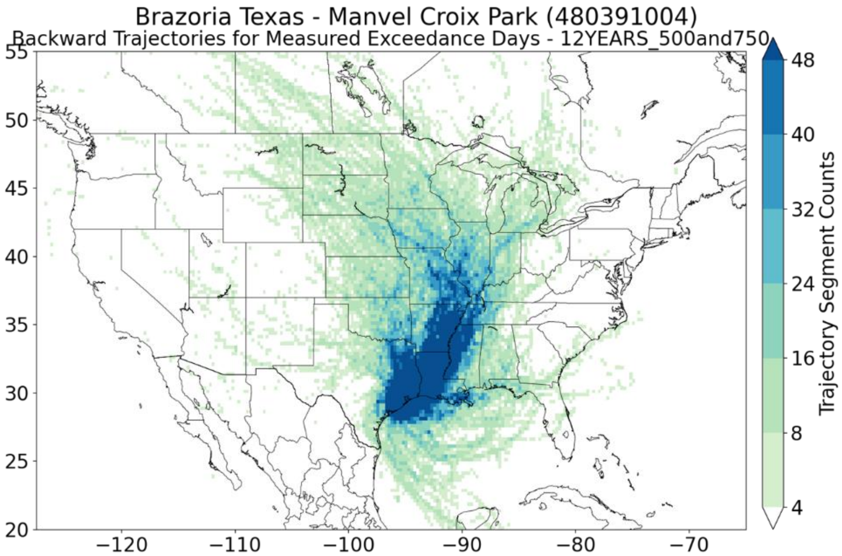
Commenter (0798) states EPA's CAMx modeling only looked at five to ten elevated ozone days and did not evaluate where the ozone and precursors arose that contributed to those days. To evaluate whether the U.S. Steel facilities in Arkansas could contribute to any of these ozone high events identified by the EPA, the commenter used HYSPLIT to calculate seventy-two hour back-trajectories for the EPA's top-ten CAMx predicted maximum daily 8-hr 2026 ozone events for the ozone monitoring site located in Brazoria, Texas. The top three ozone days had contributing air parcels originating well outside of Arkansas, or only briefly passing through the very southern section of Arkansas, and in no event originated or passed through the northeastern portion of Arkansas where the U.S. Steel facilities are located. As a result, the

U.S. Steel Arkansas facilities did not contribute to any of the events assessed by the EPA, and thus cannot be said to significantly contribute to any maintenance issues evaluated by the EPA at the Brazoria receptor. The commenter is also in the process of performing confirmatory CAMx modeling to determine the source specific contributions to the Brazoria monitor which EPA neglected to evaluate. CAMx modeling can take significant time to complete, and although we are diligently pursuing this modeling, it is impossible to complete before the June 21 comment deadline. However, because the necessity of this modeling was created by the EPA's failure to perform and/or disclose source-specific CAMx contribution modeling and unreasonably truncated public comment period, and because it bears directly on the EPA's authority to regulate U.S. Steel at all under the good neighbor provision, the EPA must consider this modeling whenever it is completed in determining applicability of any final rule to U.S. Steel facilities without running afoul of the CAA.

Response:

At Step 2, the EPA is concluding that Arkansas contributes to downwind nonattainment or interference with maintenance. This is distinct from the findings the Agency makes at Step 3 regarding which emissions from within linked upwind states are considered to "significantly contribute." The EPA further addresses this relationship in regard to non-EGU facilities in Section 2.2 of this document. As a technical matter, we disagree that emissions from the U.S. Steel Arkansas facilities are not a portion of the total Arkansas anthropogenic emissions that contribute to high ozone concentrations in Brazoria. First, when using the HYSPLIT model it is understood that the HYSPLIT back trajectory results are a central path that represents the centerline of the particles' path and there are areas on each side horizontally and vertically that also contribute to the concentrations at the end point. The horizontal and vertical areas that potentially contribute to concentrations at the endpoint grow wider from the centerline the further back in time the trajectory goes. Therefore, a HYSPLIT centerline does not have to pass directly over emissions sources or emissions-source areas but merely relatively near emissions source areas for those areas to contribute to concentrations at the trajectory endpoint and trajectories that were close to the U.S. Steel Arkansas facilities but did not necessarily pass over these facilities can still indicate the opportunity for contribution from emissions at these facilities to high ozone concentrations in Brazoria

In the EPA's 2016v3 modeling for this final action, Arkansas was found to contribute above the 0.70 ppb screening threshold to six modeling-based receptors in Texas (Brazoria, Denton, Galveston, Houston/Bayland, Houston/ East, and Houston/Clinton). The EPA ran HYSPLIT to create back trajectories from each of these receptors, among others, on days with measured ozone exceedances during the 12 years from 2010 through 2021. The maps below show the 12-year composite back trajectory analysis at 500 m and 750 m (*i.e.*, generally in the mid portion of the daytime mixed layer) for the Brazoria receptor. The map provides a visual representation of areas typically upwind wind of the receptors on days with measured exceedances at this receptor. The trajectories indicate that Arkansas is upwind of Brazoria on exceedance days. In particular, the figure below shows that a relatively high frequency of trajectories pass over northeastern Arkansas where the U.S. Steel facility is located prior to arriving over Brazoria.



Comments related to the length of the comment period are addressed in Section 10.1.

3.5.3.5 Alabama

Comment:

Commenter (0500) states for the 2021 control period, Alabama EGUs subject to the CSAPR Group 2 trading requirements emitted 6,648 tons of NO_X with total heat input of 313,037,541 mmBtu. This equates to a statewide average emissions rate of 0.042 lbs/mmBtu. This rate is below the rate identified by the EPA in the Proposal as cost-effective. Therefore, Alabama should be excluded from reductions occurring after 2023 and no cost-effective EGU reductions are available in Alabama.

Commenter (0541) states reductions from monitors 481210034 (Denton) and 482010055 (Harris) are insignificant compared to the reductions Texas can achieve on its own. And these two monitors are located in highly populated areas that owe most of their NO_X pollution to mobile sources. And, therefore, the commenter concludes that Alabama should be excluded from the rule.

Response:

The EPA's Step 3 analysis to identify reduction potential assess different EGU mitigation strategies and their availability within a state's fleet. There is no state-level cost effective rate that exempts all sources within a state from being considered for having cost-effective reduction potential. The EPA notes its Step 3 approach assumes those sources operating below the average cited by commenter are generally assumed to continue to operate at historical level with no reduction potential identified in the EPA's Step 3 analysis. However, the sources that are well above that state average cited by commenter are the ones most influencing the reduction potential for the state identified in the EPA's Step 3 analysis.

Further, whether or not local sources are also impacting a receptor has no bearing on a determination at Step 2 that a state, such as Alabama, contributes above 1 percent of the NAAQS to that receptor or a determination at Step 3 that a linked state, such as Alabama, is significantly contributing to nonattainment or interference with maintenance. Please refer to Section V.B.4 of the preamble for a discussion of mobile sources.

3.5.3.6 California

Comment:

Commenter (0237) states the FIP package issued by the EPA lacks detailed documentation for the California non-EGU source impacts at the nearby receptors. The commenter (in comment #2) notes that detailed source-specific data has not been provided for NO_X emissions reductions postulated for CA non-EGUs and for whether these reductions are significant and worthwhile, and therefore, the June 5 deadline for FIP comments becomes invalid. The commenter also states (in comment #7) that FIP failure to address CA SIP and mobile source contributions. ARB projects that the CA SIP is adequate for avoiding interstate transport (IT) impacts, and the FIP is not needed for CA sources. Any IT rule affecting Southern California needs to consider South Coast Air Basin transport to other air basins and to the Yuma Arizona monitor. The South Coast Air Basin is closer to and directly upwind of the Yuma Arizona monitor, whereas the CA non-EGU sources selected are further away and not upwind. Any IT rule affecting California needs to consider the largest NO_X sources in CA that impact attainment inside CA, and then evaluate how these sources will impact attainment in downwind states, for example, mobile sources (as postulated in the CA SIP).

Commenter (0303) states SoCal non-EGU sources have no projected impacts on any monitors other than Yuma, Arizona. Therefore, the SoCal non-EGU sources do not meet the FIP applicability criteria as set forward by the EPA elsewhere in the FIP package of documents (namely impacts on more than one monitor).

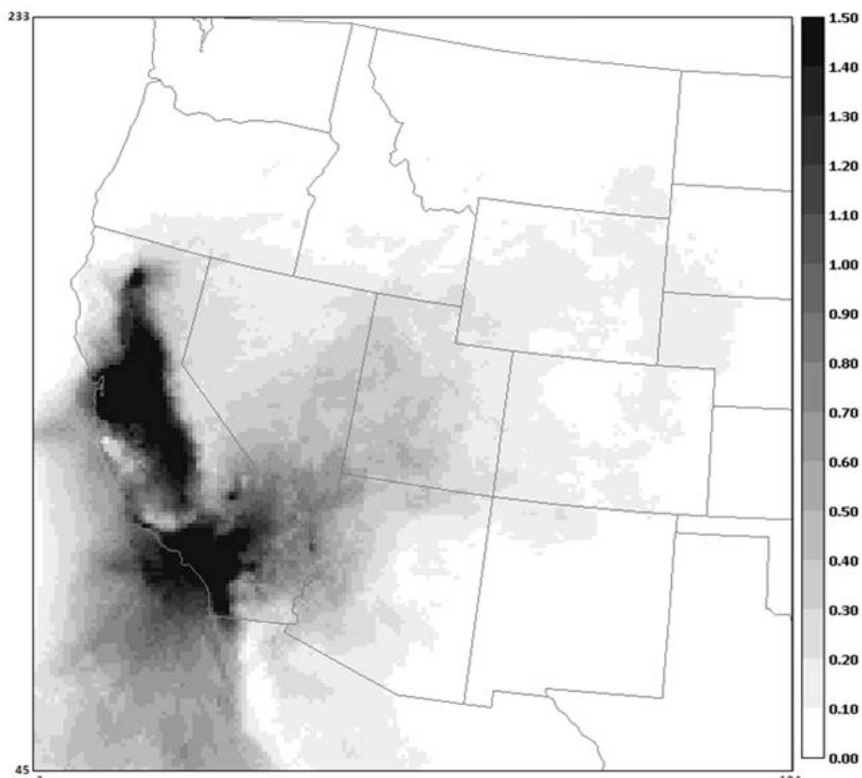
Response:

The EPA's assessment of California's good neighbor SIP submission for the 2015 ozone NAAQS is in a separate action. 88 FR 9336 (February 13, 2023). The purpose of CAA section 110(a)(2)(D)(i)(I) is to address California's significant contribution to nonattainment or interference with maintenance of the NAAQS in other states (or in tribal lands). Please refer to Section V.B.4 of the preamble for a discussion of mobile sources.

The EPA disagrees that non-EGU emissions in the South Coast Air Basin are not upwind of and impacting projected nonattainment and/or maintenance-only receptors. To support the Regulatory Impact Assessment for the proposed rule, the EPA performed state-specific contribution modeling for non-EGU point sources. In this modeling the EPA tracked the formation of ozone from emissions in the "ptnonipm" sector and sources identified as pipeline transmission of natural gas (*i.e.*, NAICS 4862). The figure below shows the average contribution from non-EGUs in California on the top 10 concentration days in each grid cell in the western U.S. The figure shows two rather distinct source areas in California one in the Central Valley and another in the southwestern part of the state including the South Coast Air

Basin. Ozone from non-EGUs in the South Coast Air Basin appears to advect east and northeastward with impacts greater than 0.10 ppb in western Arizona and southeast Nevada that extends northeastward across Utah and as far east as Denver.

Top 10 Day Contribution from California 2026 Non-EGUs Emissions



With regard to the California's Cement Manufacturer's Environmental Coalition's (Commenter 0303) statement that no southern California non-EGU sources contribute to more than one monitor, the EPA assumes the commenter is referring to the EPA's Screening Assessment requirement for Tier 1 industries. The commenter seems to be confusing the Screening Assessment methodology that looked at the entire cement industry to determine if the cement industry met the criteria for a Tier 1 industry with the applicability criteria for a particular unit. As addressed more in Section 2.2, one of the criteria for determining if an entire industry was a Tier 1 industry was whether the industry contributed >= 0.01 ppb to at least 10 receptors. Whether an individual source contributed to more than 1 receptor was not a factor considered in the Screening Assessment. Nor did the proposed or final applicability criteria under § 52.42 rely on a source contributing to more than one receptor.

3.5.3.7 Colorado

Comment:

Commenter (0492) notes that downwind states already taking aggressive steps to reduce NO_X within the state, but they are still impacted by upwind states, and it is unfair (*e.g.,* Colorado and Connecticut). In Colorado, NO_X emissions from coal-fired EGUs dropped by a dramatic 65 percent over the last ten years. (see Attachment A: Colorado Coal Units NO_X Emissions 2012–2021). According to the commenter, that drop occurred primarily because several coal-fired power plants were retired and another converted to natural gas. Of even greater importance, all remaining coal-fired EGUs in Colorado are planned for retirement, including three units alone in 2023 (Martin Drake Units 6 and 7 and Comanche Unit 1), one in 2025 (Craig Unit C1), and one in 2026 (Comanche Unit 2). In addition, Pawnee Unit 1 will convert to natural gas by 2026. Other retirements are scheduled to begin in short order after that year, and by the end of 2030 there will only be one remaining unit that burns coal in the state (Comanche Unit 3). (see Attachment B: Colorado Coal Units Summary and Attachment C: Colorado Coal Units Spreadsheets.) Of the 13 active coal-fired units in Colorado, five are already running SCR and have NO_X emissions well below the 0.08 pounds per million Btus (lb/MMBtu) rate that the EPA expects for optimized SCR in upwind states beginning in the 2023 ozone season. (see Attachments B and C). Of the remaining eight coal-fired units that are not currently operating SCR, six of them are the retirements and fuel conversion by 2026 mentioned above, meaning that by that year most of the Colorado coal fleet will be running SCR. In short, the commenter notes that Colorado has seen a dramatic decrease in its NO_X emissions from coal-fired EGUs over the last decade, and it will continue to see an important decrease in the next few years as more units retire. In the meantime, coal plants running SCR are generally obtaining significant NO_X reductions. Connecticut has already eliminated all coal-fired power plants. The last remaining unit was retired in 2021 (Bridgeport Harbor Station). In addition, more than half of the oil-fired EGUs in Connecticut already have SCR (seven out of 13). Of those seven, four are emitting far below the NO_X emissions rate of 0.03 lb/MMBtu that the EPA expects from optimizing SCR at these types of facilities in upwind states. In particular, the Devon Units 15 through 18 had 2021 ozone season NO_X rates ranging from 0.006 to 0.008 lb/MMBtu, an order of magnitude below the EPA rate. The three-remaining oil-fired EGUs with SCR at New Haven Harbor had a 2021 ozone season NO_X rate just above EPA's expected rate (0.039, for example, for Unit NHHS2), meaning that with some modest operational changes those facilities could be achieving reductions similar to what EPA is expecting from upwind EGUs, even though these Connecticut facilities are not subject to this rule. Likewise, the vast majority of gas plants already have SCR and are operating at levels below EPA's expected emissions rates in upwind states. Colorado and Connecticut have made great strides in reducing NO_X emissions from EGUs, especially by retiring coal-fired plants. Under EPA's modeling, both Colorado and Connecticut are not projected to contribute NO_X pollution to any downwind states. Yet they are projected to receive significant NO_X contributions from upwind states. As a result, these downwind states cannot protect their citizens from harmful ozone pollution, despite their aggressive regulation of NO_X sources within their borders.

Response:

Thank you for your comment.

3.5.3.8 Louisiana

Comment:

Commenter (0499) cites the Alpine report when referencing Louisiana's linkage to downwind receptors in Texas. They argue complex meteorological and photochemical conditions associated with Louisiana and Texas, the significant contribution calculations, errors in the fine grid resolution, and the use of AQAT to determine effectiveness resulted in a false linkage. The commenter states that the EPA's model failed to accurately predict ozone either by predicting a high ozone event that did not occur or entirely missing an observed ozone period. The report also asserts that the EPA failed to adequately consider wind direction shifts that alter the source/receptor relationships for the Texas and Wisconsin ambient monitors.

Response:

The EPA responds to comments on modeling ozone concentrations in near-coastal areas and areas in complex terrain and model performance in Section 3.2.2. The results of the model performance evaluation for the 2016v3 modeling platform used for this final rule can be found in the Air Quality Modeling Final Rule TSD. The EPA does not make significance determinations at Step 2. The preamble discusses the 4-step interstate framework in Section III.B. Comments related to Step 3 are addressed in Section 4 (The EPA's Quantification of Upwind State NO_X Emissions Reduction Potential to Reduce Interstate Ozone Transport). The EPA notes that AQAT is not used at Steps 1 and 2 to identify receptors or contributions. The EPA responds to comments on AQAT in Section 10.3 of this document.

Comment:

Commenter (0396) asks the EPA to reexamine the assumptions that led EPA to conclude Louisiana significantly contributes to "downwind" air quality concerns in Texas. As an initial matter, the prevailing winds from Louisiana blow the other direction. Additionally, Louisiana is a coastal state, and the Gulf Stream flows west to east, which further suggests Louisiana emissions are unlikely to actually impact Texas receptors to the west. Furthermore, Louisiana has already significantly reduced its emissions and its own ambient ozone levels in recent years. In fact, no area in Louisiana was designated as nonattainment for the 2015 ozone NAAQS of 70 ppb, and all areas achieved compliance with the 2008 NAAQS of 75 ppb no later than 2016, six years ago.

Commenter (0760) notes that in January 2018, the EPA designated all areas of Louisiana as attainment or attainment/unclassifiable with the 2015 Ozone NAAQS. The commenter's (LDEQ) process for analyzing the significance of contributions in the Louisiana Transport SIP on Texas included an applicable weather pattern analysis and a wind rose analysis. Further, at the request of the EPA, LDEQ conducted back trajectory analysis of high ozone days in Texas using the HYSPLIT Model developed by the National Oceanic and Atmospheric Administration (NOAA). The EPA requested that LDEQ conduct this analysis. The EPA modeling is based on a single base year whereas use of HYSPLIT for back trajectory analysis provides a better understanding of how Louisiana emissions may affect ozone in Texas over a broader time period. Louisiana analyses using the HYSPLIT model demonstrated that air quality within the HGB area on high ozone days was primarily influenced by air parcels that did not travel over Louisiana. Louisiana's proposed SIP concluded that the state's emissions had not contributed significantly to past high ozone events in the HGB Area or the Dallas-Ft.

Worth Area and were unlikely to do so in the future.

Response:

While Louisiana may have reduced emissions in recent years, they have not decreased sufficiently for the EPA to reach an alternative conclusion about whether Louisiana significantly contributes to nonattainment or interferes with maintenance in other states. The EPA generally already accounts for enforceable controls in its modeling along with using data such as the most recently available NEI, and the EPA's modeling still identifies that Louisiana contributes above 1 percent of the NAAQS to one or more downwind receptor.

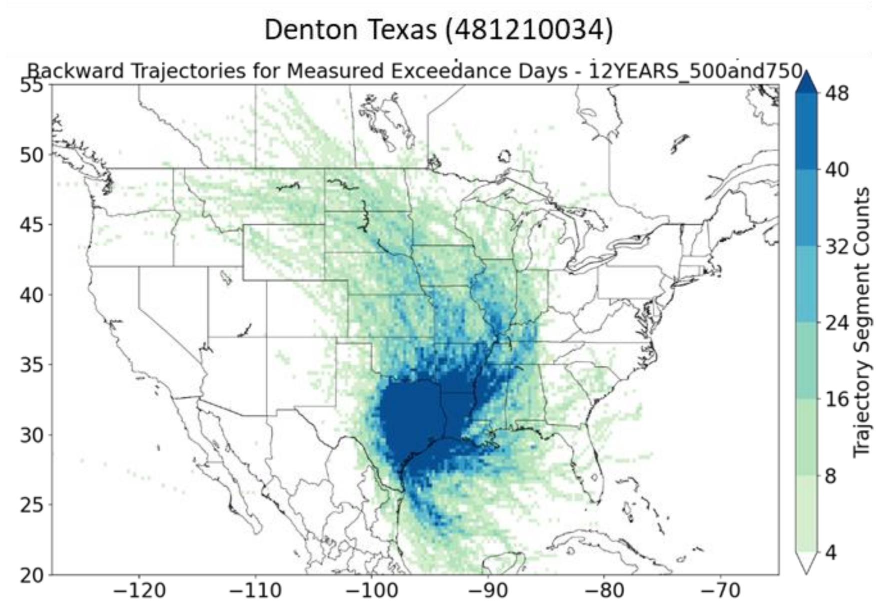
The EPA disagrees emissions from Louisiana do not blow westward at times, or that a HYSPLIT model analysis performed by LDEQ in the state's SIP submission support a conclusion that Louisiana does not significantly contribute to nonattainment or interference with maintenance in receptors in Texas. The EPA evaluated Louisiana's HYSPLIT analysis which was included as part of the state's good neighbor SIP submission for the 2015 ozone NAAQS. *See* 87 FR 9798, 9812-9815 (Feb. 22, 2022); 88 FR 9336 (Feb. 13, 2023). The EPA does not believe that HYSPLIT analyses are sufficient to determine significant contribution because HYSPLIT trajectory analyses, as run by LDEQ, do not provide any quantitative measure of contribution. Quantitative contributions are necessary to evaluate the magnitude of an upwind state's contribution to downwind receptors with respect to the 1 percent of the NAAQS screening threshold used in Step 2 of the 4-step interstate transport framework. HYSPLIT does not account for air pollution formation from emissions of precursors (e.g., NOx and VOC emissions react to form ozone), dispersion, transformation, or removal processes as influenced by chemistry, deposition, etc., so the trajectories cannot be used to develop quantitative amounts for how much ozone was formed at the downwind receptor from emissions of pre-cursors in the state of Louisiana.

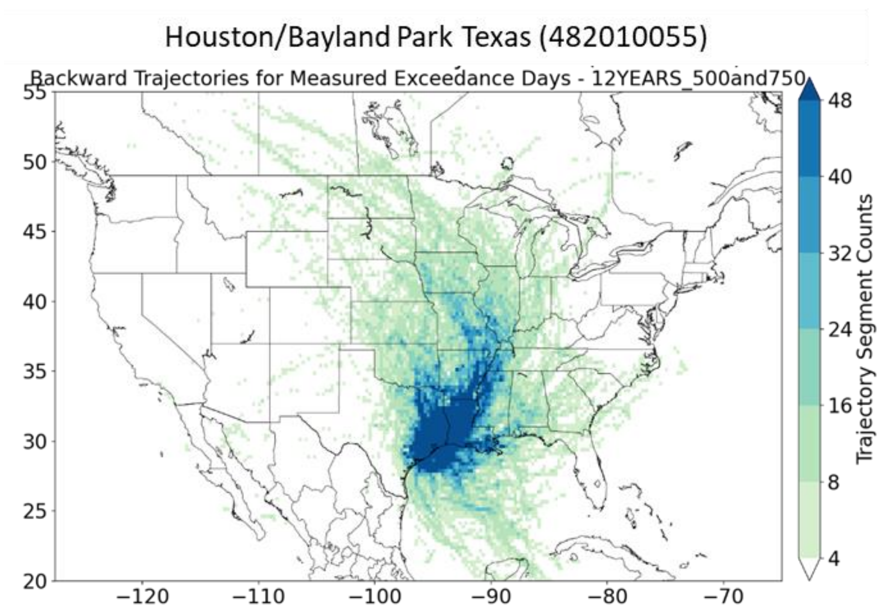
EPA did provide comments on a draft, pre-submittal version of Louisiana's good neighbor SIP submission and recommended LDEQ perform HYSPLIT analyses to evaluate the transport meteorology as a way to refine the technical analysis that LDEQ was performing for their SIP submission. However, this was not an endorsement of HYPSLIT as a way to identify significant contribution. Moreover, the EPA's Guideline on Air Quality Models[72] specifically states that "Control agencies with jurisdiction over areas with ozone problems should use photochemical grid models to evaluate the relationship between precursor species and ozone." Because the amount of interstate ozone transport is dependent in large part on the ability to credibly quantify ozone and precursor species concentrations, the EPA finds that photochemical grid modeling, rather than trajectories designed to track transport of non-reactive (*i.e.*, inert) pollutants, is the appropriate method for quantifying and evaluating interstate contributions.

In response to comments on the use of trajectories, the EPA ran HYSPLIT to create back trajectories from each of these receptors, among others, on days with measured ozone

[72] *Guideline on Air Quality Models* ("Appendix W" to 40 CFR part 51), section 5.3.1, page 5213.

exceedances during the 12 years from 2010 through 2021. The maps below show the back trajectories from the Denton and Houston receptors for elevations of 500 m and 750 m (*i.e.*, generally in the mid portion of the daytime mixed layer). These maps provide a visual representation of areas typically upwind wind of the Denton and Houston/Bayland receptors on days with measured exceedances at these locations. The trajectories indicate that the air can travel from east to west such that Louisiana is upwind of the Denton and Houston receptors on days when ozone exceeds the NAAQS. This result confirms the EPA's finding that Louisiana is linked to these receptors in Texas.





3.5.3.9 Missouri

Comment:

Commenter (0289) states there is only one monitor in Cook County, Illinois where Missouri is linked at Step 2 in the updated modeling, yet there are over a dozen other monitors in the county, and the next highest linkage to Missouri is 40 percent less than Missouri's linkage to this single monitor. With respect to the receptor in Chicago, IL, to which the updated modeling links Missouri, no other receptors in Cook County, IL are linked to Missouri at Step 2. This calls into question the validity and assuredness of the model performance when it comes to the source apportionment techniques. In EPA's spreadsheet listing the DVs and upwind state contributions, there are 10 receptors located in Cook County with available data all located in relatively close proximity to the newly identified linked receptor for Missouri. While the contribution identified from Missouri for the one linked receptor in Cook County is 0.94 ppb, the receptor with the next highest Missouri contribution is 0.56 ppb, approximately 40 percent less. From a practical standpoint it makes no sense that Missouri is contributing to this single receptor above the 1 percent threshold since there are nine other monitors in the same county where Missouri's contribution is at least 40 percent less than the modeled contribution to that problem receptor. This calls into question the ability of the model to determine significant contribution levels and the arbitrary nature of the 1 percent threshold at Step 2.

Response:

As explained in the Air Quality Modeling Proposed Rule TSD, as well as the Air Quality Modeling Final Rule TSD the EPA's methodology for calculating contributions is based on the average of daily contributions on the days with the top 10 model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in the future year modeling. If there are fewer than 10 modeled days that meet this criterion for the given receptor, then the average contribution is calculated based on the remaining days greater than or equal to 60 ppb, providing that there are at least five days with modeled MDA8 values greater than or equal to 60 ppb. Average contribution metric values are not calculated for a receptor if there are fewer than 5 days with future year modeled MDA8 ozone concentrations at or above this threshold.

Based on the air quality modeling performed for this final rule, the EPA identified four receptors in Cook County, Illinoi**s**. Table 3-22, below provides the average contribution metric values (ppb) for Missouri's contribution to each of these receptors, based on the final rule modeling. The data show that there are large differences between the receptors in the magnitude of the average contribution from Missouri. These differences are due to the fact that each receptor has a different set of days that comprise the top 10 days that are used to calculate the average contribution metric. This is evident from the data in Table 3-23 which provides the daily concentrations and contributions in 2023 on each day that was among the top 10 days at any one of these receptors. The days are ranked based on the magnitude of the 2023 ozone concentration at the Evanston receptor to which Missouri contributes 1.39 ppb. The data for these 10 days are highlighted in the table. Aside from a few exceptions, the days with high contributions from Missouri to Evanston (*i.e.*, 05/25, 06/15, 07/07, 07/20, 07/22, and 08/10) are also the days with high contributions from Missouri at the other two receptors in Cook County. The days that were among the top 10 days at the Alsip and Northbrook receptors, but not among the top 10 days at Evanston had very low contributions from Missouri. For example, the top 10 days at Northbrook did not include 06/15, 07/20, and 07/22, each of which had contributions from Missouri greater than 1 ppb. Instead of these days, the top 10 days at Northbrook included 07/26, 08/02, and 08/10 each of which had much lower contributions from Missouri. As a result, the average contribution from Missouri to Northbrook is less than the 0.70 ppb screening threshold. Based on the results of this analysis, the EPA disagrees with the commenter's contention that the contributions from Missouri and not "valid" and the 1 percent threshold is arbitrary.

Table 3-22

Receptor	***Missouri Contribution***
Evanston	1.39
Alsip	0.37
Northbrook	0.54

Table 3-23

	Evanston 170317002			Alsip 170310001			Northbrook 170314201		
Date	**Rank**	**2023 MDA8 O3**	**Missouri's Contribution**	**Rank**	**2023 MDA8 O3**	**Missouri's Contribution**	**Rank**	**2023 MDA8 O3**	**Missouri's Contribution**
08/04	**1**	83.87	0.080	**-**	63.34	0.056	**2**	78.39	0.077
06/15	**2**	79.77	2.136	**-**	65.71	1.243	**-**	66.94	1.647
07/07	**3**	79.52	3.581	**-**	54.78	3.394	**6**	72.87	2.787
07/27	**4**	78.15	0.000	**-**	60.76	0.000	**3**	76.24	0.000
06/25	**5**	75.67	1.016	**-**	64.21	1.537	**8**	70.90	1.282
07/22	**6**	74.35	2.025	**7**	69.12	1.633	**-**	68.00	1.658
07/20	**7**	73.05	0.876	**-**	59.57	0.557	**-**	67.67	1.146
08/03	**8**	71.87	0.474	**6**	69.88	0.291	**5**	73.68	0.516
07/23	**9**	71.68	0.505	**4**	74.91	1.001	**1**	83.52	0.541
08/11	**10**	69.08	4.733	**-**	59.88	5.144	**-**	63.03	4.909
08/10	-	69.05	0.558	**3**	75.27	0.573	**4**	75.67	0.680
07/26	-	63.01	0.000	**9**	68.69	0.000	**10**	69.55	0.000
08/02	-	63.00	0.064	-	62.41	0.106	**7**	72.17	0.083
07/18	-	61.03	0.153	**2**	76.14	0.233	-	65.08	0.110
07/19	-	59.44	0.012	**1**	78.61	0.045	**9**	70.10	0.011
06/03	-	58.65	0.052	**8**	68.98	0.218	-	59.76	0.112
07/25	-	54.88	0.000	**5**	72.88	0.001	-	51.11	0.000
06/18	-	50.24	0.001	**10**	65.99	0.005	-	52.37	0.001

Comment:

Commenter (0521) states Missouri's monitoring network and more specifically Springfield/Greene County monitors show compliance with the 2015 ozone NAAQS and it is inappropriate to require additional controls. Missouri has proven to be a good neighbor, and the utilities and the citizens of Missouri have paid for the ambient air quality improvements realized in Missouri and in downwind states. These reductions are no small task for the customer-owners in the Springfield-Greene County area. It is inappropriate to require additional costs and economic hardships for the rate payers of City Utilities, when City

Utilities has consistently been a good actor operating its control equipment while, at the same time, our area, region, and state have considerably met the applicable ozone NAAQS.

Response:

The EPA disagrees that Missouri has satisfied its good neighbor obligation because monitors in that state are measuring attainment of the 2016 NAAQS. As an upwind state, Missouri is required to eliminate significant contribution to nonattainment/maintenance problems in other (downwind) states. The mere fact that Springfield/Greene County is in compliance with the NAAQS does not mean that emissions from Missouri, as a whole, do not make a significant contribution to nonattainment and/or maintenance problems in other states. See response to comment below in Section 3.5.3.10 regarding the mechanisms of transport of ozone-precursor emissions.

3.5.3.10 Mississippi

Comment:

Commenter (0500) states that Mississippi does not contribute to nonattainment in 2026 and should not be subject to the draconian cuts. According to the Agency's analysis, the state of Mississippi is linked to multiple nonattainment receptors in 2023, but to only one maintenance receptor in 2026. Yet, Mississippi's 2026 illustrative budget suggests a 62 percent reduction in allowances from 2023 to 2026 (5,024 tons to 1,914 tons). For budget purposes, the commenter suggests that the EPA treats a state that does not contribute to nonattainment but does contribute to maintenance the same as a significant contributor to nonattainment. This results in Mississippi receiving the same budget as if it were still contributing to multiple nonattainment receptors in 2026. In support of this conclusion, 42 U.S.C. Section 7505a(d) requires the state SIP in which a maintenance receptor is located to "include a requirement that the state will implement all measures with respect to the control of the air pollutant concerned which were contained in the SIP for the area before redesignation of the area as an attainment area." The "home" state is not required to take additional action to ensure its maintenance areas continue to maintain the NAAQS. It is only required to continue the measures implemented before redesignation. The EPA should adopt a similar approach and hold reductions of precursor emissions for states that significantly contribute to only a maintenance receptor. Doing so will properly align the requirements for upwind, contributing, states and downwind, maintenance, states. To require additional reductions from upwind states, while allowing the downwind state with the affected maintenance area to hold its reductions in precursor emissions steady is inappropriate.

Response:

The EPA continues its same approach to addressing maintenance-only receptors as it has in prior rules and disagrees with the commenter that this is excessively stringent or out of alignment with the statutory structure. See Section 3.1 (Years Selected for Analysis). The EPA has been upheld in this approach, *see Wisconsin*, 938 F.3d at 325-27; *see also EME Homer City*, 795 F.3d at 136-37. This approach ensures that prong 2 of the good neighbor provision is given independent effect, which complies with the holding in *North Carolina*, 531 F.3d at 909-

10.

Comment:

Commenter (0300) states that meteorological research into the EPA's reliance on the air quality modeling for the 2016v2 Emissions Modeling Platform and Mississippi's alleged significant (*i.e*., greater than or equal to 1 percent threshold) contributions to receptors in Texas indicates that Mississippi, in fact, has no significant contributions to monitors in Brazoria (Manvel Croix Park, site ID# 48031004), Denton (Denton Airport South, site ID# 481210034), or Harris County (Houston Bayland Park, site ID# 482010055), Texas for nitrogen oxide (NO_X) and volatile organic compounds (VOC) pollutants to contribute to secondary O3 formation.

In most occurrences of high ozone days in Brazoria, Denton, and Harris County, Texas, the Houston and/or Dallas core-based statistical areas (CBSA), as applicable, are under very stagnant conditions with minimal mixing allowing O3 to build (Figures 15-17). Thorough research shows no correlation when Brazoria, Denton, and Harris County, Texas, experience an easterly fetch (*i.e.*, easterly winds), which is the only time Mississippi emissions could conceivably contribute to high ozone in these areas.

Regarding meteorological influence, commenter (0300) says that Mississippi has a negligible and insignificant effect on VOC/NOX transport to contribute downwind to Texas air monitoring sites. On days where Harris, Brazoria, and Denton NAAQS exceedances occur, the ozone development was locally driven, as shown by the following back trajectories. Back trajectories show the red parcel originating in Mississippi and moving downwind into Texas. Ground-level 8-hr O3 averages in Mississippi were in the green category (*i.e.*, good) in the previous days, as noted by MDEQ air monitoring sites.

Commenter (0300) argues the contributions to receptors in Texas indicate Mississippi, in fact, has no significant contributions to monitors in Brazoria (Manvel Croix Park, site ID# 48031004), Denton (Denton Airport South, site ID# 481210034), or Harris County (Houston Bayland Park, site ID# 482010055), TX for nitrogen oxide (NO_X) and volatile organic compounds (VOC) pollutants to contribute to secondary O3 formation. In most occurrences of high O3 days in Brazoria, Denton, and Harris County, TX, the Houston and/or Dallas core-based statistical areas (CBSA), as applicable, are under very stagnant conditions with minimal mixing allowing O3 to build. Thorough research shows no correlation when Brazoria, Denton, and Harris County, TX, experience an easterly fetch (*i.e.*, easterly winds), which is the only time Mississippi emissions could conceivably contribute to high O3 in these areas.

Commenter (0300) provides multiple figures showing wind roses from Houston Intercontinental Airport. They show wind speed and direction during the three-year period 2018-2020. 72-hr back trajectories demonstrate stagnant conditions resulting in a minimum distance traveled over the past 72 hours. According to the commenter, the majority of the winds blow from the south and south/southeast. Less than 2 percent of the duration does the wind blow from the east/east-northeast (*i.e.*, from Mississippi, geographically). Commenter (0542) states that Texas is geographically located upwind of Mississippi. Review of meteorological data indicates most occurrences of high ozone days in the Texas receptors occurred under stagnant conditions, not on the rare instances when the wind was blowing from east to west.

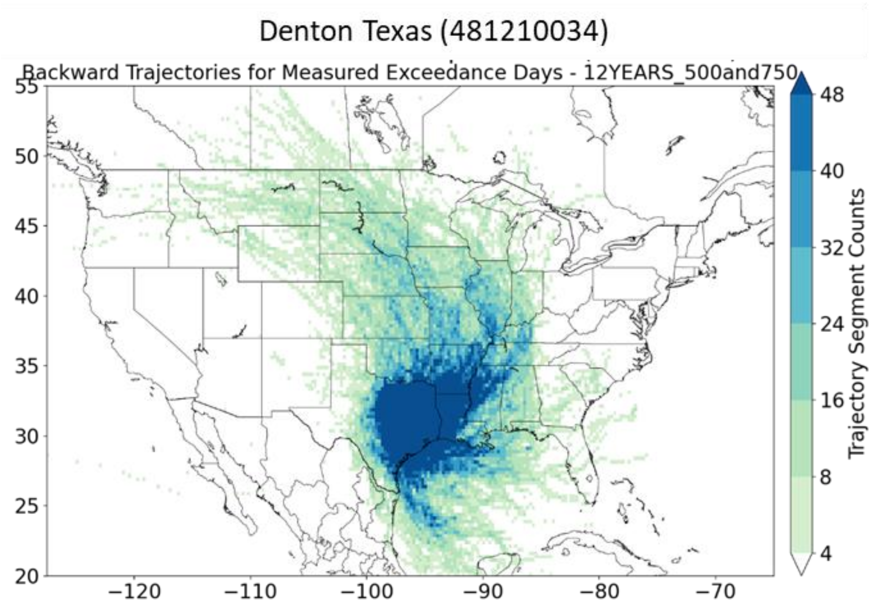
Response:

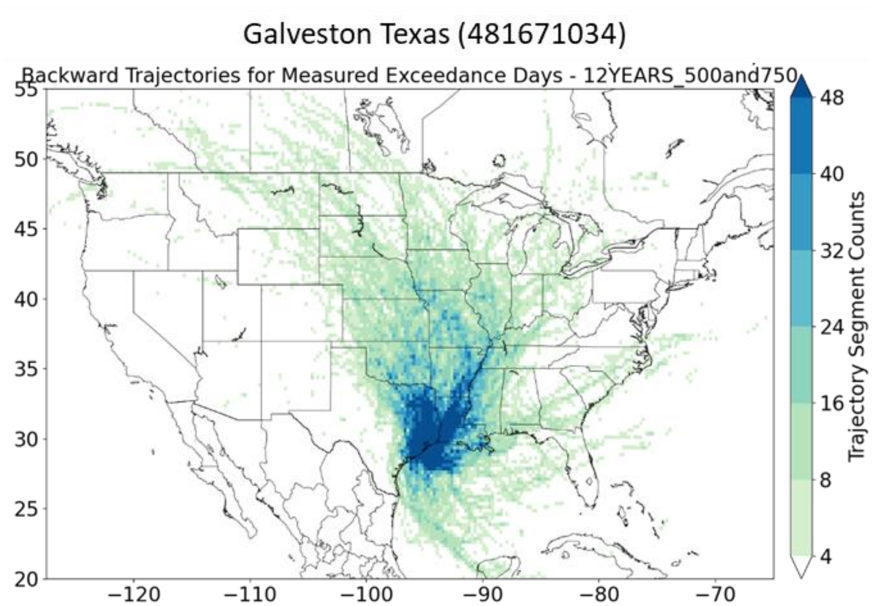
The EPA found that emissions in Mississippi were linked to downwind receptors in Brazoria County (monitoring site 48031004), Denton County (monitoring site 481210034) and Harris County (monitoring site 482010055), TX based on the 2016v2 modeling. The commenter claims that Mississippi should not be identified as linked to these receptors because they claim that air is very stagnant on days with measured exceedances at these receptors and air rarely moves from Mississippi west toward Texas on exceedance days. The commenter relies upon analyses of near ground-level wind flow (*i.e.*, wind roses) and HYSPLIT-based multi-day back trajectories on days with measured exceedances at these receptors to support their claims that Mississippi should not be linked to these receptors.

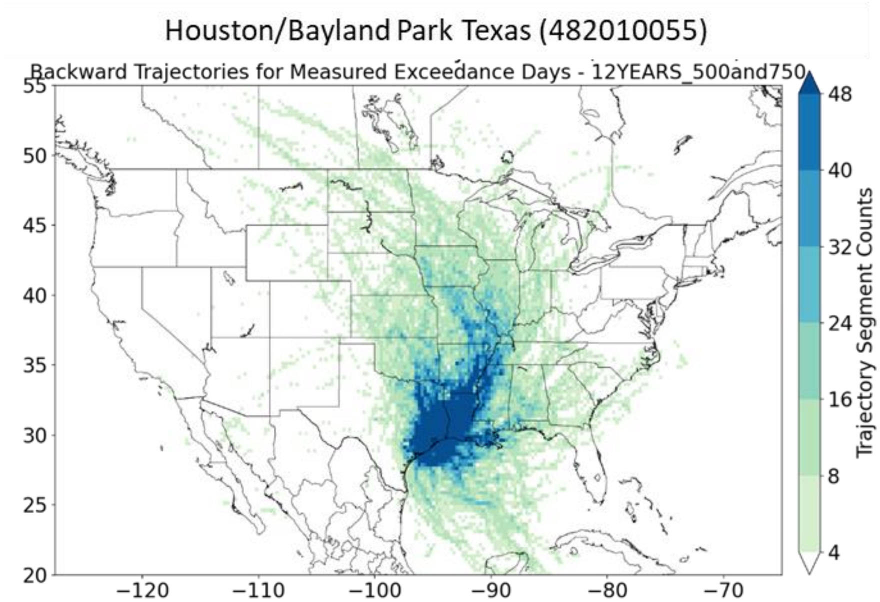
The EPA disagrees that the Agency should conclude that sources in Mississippi do not contribute to nonattainment or maintenance receptors in Texas. First, regional pollutant transport occurs when ozone precursor emissions (*i.e.*, NO_X and VOCs) from sources in an upwind state are emitted into the air and form ozone. The photochemical reactions that form ozone also form “by-product” pollutants that are “recycled” to form additional ozone farther downwind. The ozone and by-product pollutant species are vertically mixed due to dispersion and updrafts/downdrafts within the daytime boundary layer (*i.e.*, the mixed layer) during the day. Variations in wind speed and direction between the ground and the mid-to-top of the daytime mixed layer can result in different transport patterns aloft than near the ground. In addition, pollutants formed during the day that remain aloft over night or are emitted aloft during the night above the very shallow nighttime surface layer can be transported long distances due to the effects of the “nocturnal jet,” which is a high-speed ribbon of air that forms above the top of the nighttime surface layer. In addition, wind speed typically increases with height within the mixed layer, because the effects of surface roughness, which reduces wind speed near the ground, diminishes with height. Pollutants transported downwind aloft are typically brought down to the ground on subsequent days beginning in mid-morning as the height of the mixed layer rises. By this process pollutants transported aloft from upwind states can contribute to high ozone concentrations at monitoring sites in downwind states. While wind roses and trajectories based on data near or within a few hundred meters of the ground are useful for analyzing local scale transport (*i.e.*, within an urban area) such analyses generally will not provide particularly reliable or meaningful information on long-range, multi-day transport of ozone and by-product pollutants aloft.

In the EPA’s 2016v3 modeling for this final action, Mississippi was found to contribute above the 0.70 ppb screening threshold to three modeling-based receptors in Texas (*i.e.*, Denton County monitoring site 481210034, Galveston County monitoring site 482671034, and Harris County monitoring site 482010055) as well as six violating monitor receptors in Texas. The contributions from Mississippi to all receptors can be found in the Air Quality Modeling Final Rule TSD and in the file “Final GNP O3 DVs_Contributions.xls,” which are both in the docket for this final rule.

The EPA ran HYSPLIT to create back trajectories from the Denton, Galveston, and Houston receptors, among others, on days with measured ozone exceedances during the 12 years from 2010 through 2021. The maps below show the back trajectory analysis for the receptor-based trajectories at 500 m and 750 m (*i.e.*, generally in the mid portion of the daytime mixed layer). The map provides a visual representation of areas typically upwind wind of these three receptors on days with measured exceedances at the receptor. The trajectories indicate that the air can travel from northeast to southwest such that Mississippi is upwind of each receptor on exceedance days. This result confirms the EPA's finding that Mississippi is linked to receptors in Texas. The EPA's back trajectory analysis is described in the Air Quality Modeling Final Rule TSD.







3.5.3.11 Oklahoma

Comment:

Commenter (0517) states Oklahoma is being penalized for having cleaner air than downwind states. It does seem that Oklahoma sources are required to install costly controls to address a much smaller quantity of emissions moving south while sources in Texas have no requirement to address emissions impacting Oklahoma receptors since Oklahoma is in attainment. It is illogical that sources in Texas will be required to control emissions to reduce impacts on receptors in Wisconsin and Illinois, but not Oklahoma.

Response:

The EPA identifies nonattainment and maintenance receptors based on the approach described in Section IV of the final rule preamble and in the Air Quality Modeling Final Rule TSD. There are no monitoring sites in Oklahoma that are measuring nonattainment based on 2021 DVs nor are there any monitoring sites that are projected to be nonattainment or maintenance-only receptors in 2023 or 2026 based on the EPA's modeling for the final rule. This is not to say Oklahoma will not experience air quality benefits from this rule. The EPA performed air quality modeling to quantify the "ppb" impacts of the final rule control case in 2026 analyzed in the Regulatory Impact Assessment (RIA). The table below provides the impacts of the 2026 control case emissions reductions on ozone DVs at monitoring sites in Oklahoma. On average, ozone DVs are expected to be reduced by 1.0 ppb at monitors in this state. Additional information on the EPA's control case modeling can be found in the Air Quality Modeling Final Rule TSD.

Table 3-24

AQS ID	***County***	***Estimated Impact (ppb)***
400019009	Adair	-1.46
400170101	Canadian	-0.31
400219002	Cherokee	-1.98
400270049	Cleveland	-0.23
400370144	Creek	-1.30
400719010	Kay	-0.58
400871073	McClain	-0.20
400979014	Mayes	-4.47
401090033	Oklahoma	-0.21
401090096	Oklahoma	-0.24
401091037	Oklahoma	-0.39
401159004	Ottawa	-2.17
401210415	Pittsburg	0.35
401359021	Sequoyah	-1.16
401430174	Tulsa	-1.24
401430178	Tulsa	-0.54
401431127	Tulsa	-1.35

3.5.3.12 Texas

Comment:

Commenter (0763) states Texas will attain compliance and is not a significant contributor to neighboring states is predicated on a history of inaccurate assumptions and arguments that have continually failed to yield accurate results.

Response:

The EPA disagrees. The EPA is identifying in this rule that Texas is both a downwind and an upwind state. The EPA finds, based on the air quality modeling for this final rule, that monitoring sites in the Dallas area and Houston area will have difficulty attaining and or maintaining the NAAQS in 2023 and have been identified as receptors at Step 1. The projected DVs in 2023 and 2026 for monitoring sites nationwide can be found in the file “Final GNP O3 DVs_Contributions.xls” which is in the docket for this final rule. Further, Texas contributes above 1 percent of the NAAQS to one or more downwind receptors.

The EPA addresses specific criticisms of its modeling elsewhere in the RTC.

3.5.3.13 Utah

Comment:

Commenter (0378) states Utah's interstate transport SIP is approvable, and Utah should not be included in the GNR. In January 2020, Utah submitted its SIP to address interstate transport to downwind states under the 2015 ozone NAAQS. At issue for Utah is the contribution from Utah emissions to air quality in Colorado. The UDAQ detailed in the SIP how it met EPA's requirements for interstate transport using a 1 ppb threshold instead of a threshold of 1 percent of the NAAQS (0.7 ppb) which EPA used to judge the Utah SIP. Relative comparisons of the Utah contribution to Colorado are particularly important considering the CAA applicability requirement to address those contributions that contribute significantly to downwind states. The commenter provided a lengthy analysis showing how its approach matches other interstate transport SIP approvals and EPA guidance, including the following:

- Comparison to an approved Arizona SIP that relied on a 1 percent contribution to California.
- Analysis showing how Utah meets the recommendations of EPA's August 2018 memo discussing the possible use of different contribution thresholds.
- Comparison showing that the total magnitude of upwind state contributions to Colorado are small in comparison to the magnitude of in-state contributions, the opposite of what occurs in the northeastern states where upwind states contribute far more than in-state emissions.
- Analysis showing that Utah's contribution to Colorado is very small in comparison to the non-controllable portion of ozone in Colorado.
- Analysis showing significant reductions in emissions in Utah after the time of EPA's modeling study quantifying impacts to downwind states, including a number of actions related to applying Best Available Control Technology and Best Available Control Measures for the Salt Lake City $PM_{2.5}$ nonattainment area, implementing controls in the Uinta Basin on oil and gas sources to reduce ozone formation, and implementation of Tier 3 gasoline.

According to the commenter, EPA should have completed the SIP approval or disapprovals prior to publishing a FIP per the requirements of CAA § 110(c)(1) which identifies when EPA must promulgate a FIP. Furthermore, Utah's SIP is approvable as submitted. Comments on the Utah Interstate Transport Proposed Disapproval are inextricably linked with comments on the GNR. Without a final Utah SIP disapproval, Utah should not have been included in the proposed GNR.

Commenter (0378) notes the EPA applied photochemical modeling decisions inconsistently across rulemakings, especially considering the margin of error. The commenter quotes Ozone NAAQS: "Due to the complex terrain, meteorology, distance between sources and receptors, and somewhat coarse-grained modeling inputs the margin of error in the transport modeling in the Intermountain West is about 15%", and states if this margin of error to determine those states that contribute significantly to ozone in downwind states, 15 percent of the 70-ppb ozone NAAQS suggests that controls would only be required in states contributing 10 ppb or more to downwind ozone. This margin of error is applied to determine those states that contribute significantly to ozone in downwind states, 15 percent of the 70-ppb ozone NAAQS suggests that controls would only be required in states contributing 10 ppb or more to downwind ozone. This is more in line with the contributions to downwind states in the northeastern part of the United States. The EPA's use of its modeling study to support its decision to include Utah in the GNR is wholly inconsistent with the EPA's proposed disapproval of the 179B demonstration for Utah's NWF ozone nonattainment area (NWF). In NWF case, the EPA strongly criticized the modeling for underpredicting local ozone production and, as a result, the EPA did not agree with the model demonstration of 6 to 8 ppb international influence on NWF ozone. On the other hand, the EPA's model for the GNR rulemaking also showed significant underprediction of both Utah and Denver ozone by as much as 10 to 20 ppb on high ozone days, and yet the EPA used these model results despite the poor performance to evaluate downwind impacts of only 1 ppb or 0.7 ppb. The model simply does not have the accuracy for these small predictions to be reliable.

Furthermore, the EPA questioned the accuracy of 2 to 3 ppb in Texas' model for its 179B demonstration for the San Antonio ozone nonattainment area (SAT) because the 2 to 3 ppb influence falls within the range of model uncertainty. If modeling does not have enough accuracy in the San Antonio case to show a 2-3 ppb impact, it also does not have enough accuracy to show a 0.7 ppb or 1 ppb impact for the GNR. In fact, in the San Antonio case, Texas developed a model specifically for San Antonio, a more detailed and accurate exercise than the EPA's larger modeling domain and coarser grid for the interstate transport evaluations, and San Antonio lacks the complex terrain of Salt Lake City and Denver. Therefore, the San Antonio modeling has less inherent inaccuracy. The EPA cannot have it both ways. If a 6 to 8 ppb difference and a 2 to 3 ppb difference do not have sufficient accuracy to show upwind impacts in the NWF and SAT 179B demonstrations, respectively, then a 1 ppb or 0.7 ppb difference would not be sufficiently accurate in the GNR, considering the magnitude of inherent error in the modeling. Finally, the commenter states the EPA can only resolve this arbitrary and capricious dichotomy by removing Utah from the GNR.

Response:

The EPA finalized a disapproval of Utah's SIP submission, as well as several other states, in a separate action. 88 FR 9336 (Feb. 13, 2023). The EPA has a separate statutory obligation to promulgate a FIP for Utah flowing from the finding of failure to submit which predates the SIP submission disapproval. 84 FR 66612 (Dec. 5, 2019, effective Jan. 6, 2020); CAA section 110(c)(1). Comments related to the sequencing of SIP and FIP actions are addressed in Section 1.1 (Sequencing of SIP and FIP actions). Comments related to the EPA's emissions inventories are addressed in Section 3.3.

The EPA is applying a 1 percent of the NAAQS threshold at Step 2, as explained in the preamble in Section II.B, and Utah's highest-level contribution is 1.29 ppb to Douglas County, Colorado (AQS Site ID 080350004) (2016v3 modeling). The rationale underpinning the EPA's approval of Arizona's 2008 ozone NAAQS good neighbor SIP submission is inapplicable to the Douglas County, Colorado receptor. Twenty-seven percent of the ozone from U.S.

anthropogenic NOx and VOC emissions at this receptor is attributable to the contribution from upwind states. Whether or not local sources also impact Utah's linked receptors is not relevant to the inquiry of whether Utah is itself significantly contributing to nonattainment or interfering with maintenance to those receptors.

One commenter claimed that it is arbitrary and capricious for the EPA to reject Utah's 179B(b) demonstration due to model underperformance while simultaneously using a model with similar underperformance limitations as justification to include Utah in the FIP.

First, CAA section 110(a)(2)(D)(i)(I) and CAA section 179B are different provisions to address different problems and are governed by their own respective requirements, and as such do not require the same approach to implementation. We have addressed this previously in prior ozone transport rules, and we are not reopening our policy on this point. *See* CSAPR Update, 81 FR 74535-36 (Oct. 26, 2016). As we explained there:

> [T]he specific terms of section 179B outline which nonattainment area requirements will and will not apply upon approval of a section 179B demonstration, none of which apply directly to upwind states via section 110(a)(2)(D)(i)(I). In particular, the good neighbor provision does not require upwind areas to ''demonstrate attainment and maintenance'' of the NAAQS. Rather, the statute requires upwind states to prohibit emissions which will ''contribute significantly to nonattainment'' or ''interfere with maintenance'' of a NAAQS. . . . [W]hile upwind states must address their fair share of downwind air quality problems, the EPA has not interpreted this provision to hold upwind areas responsible for bringing downwind areas into attainment. Therefore, the relief provided by section 179B(a) and (b) from the obligation to demonstrate attainment, extension of the attainment date, and mandatory reclassifications, is simply not applicable to [upwind] states.
>
> Even if section 179B were in some manner applicable to upwind states' transport obligations, the EPA does not believe that the contribution of international emissions should impact EPA's identification of downwind nonattainment and maintenance receptors affected by the interstate transport of emissions. These receptors represent areas that the EPA projects will have difficulty attaining and maintaining the NAAQS, and which therefore require adequate safeguards to protect public health and welfare. The EPA therefore does not agree that, when identifying downwind air quality problems for purposes of interstate transport, section 179B requires that we subtract the contributions of international emissions from the projected DVs. This would be inconsistent with EPA's approach to area designations and is simply not required by the plain language of the statute. Moreover, such an interpretation would allow downwind and upwind areas to make no efforts to address clear violations of the NAAQS, leaving the area's citizens to suffer the health and environmental consequences of such inaction.
>
> Moreover, just as any state with a nonattainment area— including downwind states— must take reasonable steps to control emissions even where an area is impacted by international emissions, the EPA determines that it is appropriate for upwind states to also adopt reasonable emissions controls to lessen the impact of emissions generated in their state and subsequently transported to downwind areas. As noted in Section IV of the

> preamble, the EPA does not view the obligation under the good neighbor provision as a requirement for upwind states to bear all of the burden for resolving downwind air quality problems. Rather, it is an obligation that upwind and downwind states share responsibility for addressing air quality problems. If, after implementation of reasonable emissions reductions by an upwind state, a downwind air quality problem persists, whether due to international emissions or emissions originating within the downwind state, the EPA can relieve the upwind state of the obligation to make additional reductions to address that air quality problem. But the statute does not absolve the upwind state of the obligation to make reasonable reductions in the first instance.

We note that the EPA was upheld in its approach to the treatment of international contribution in *Wisconsin*, 938 F.3d at 323-24.

We disapproved Utah's 179B demonstration using a weight of evidence approach; as described in detail in the TSD, RTC and final rule, there were a number of reasons why the demonstration was not approvable, including a comparison of the modeled international contribution to the degree of violation and domestic contribution (*See* TSD, North Wasatch Front (NWF)), Utah: Failure to Attain 2015 Ozone National Ambient Air Quality Standard by Attainment Date; Reclassification and Disapproval of International Emissions Demonstration January 2022, *found at* Regulations.gov at EPA-HQ-OAR-2021-0742-0043). The EPA will not here restate all our reasons for disapproving Utah's 179B demonstration, as that information is provided in the TSD, RTC, and final rule for that action. Comments relating to CAA section 179B are outside the scope of this action. The model performance was considered in the context of the information provided and in the context of the conclusion being drawn, but was not the sole deciding factor, as is discussed in detail in that action.

In addition, the EPA disagrees with the interpretation of model performance implications as stated by the commenter. With respect to model performance, the EPA notes that the type of conclusions needed for CAA section 179B and for the proposed rule have very different implications for the evaluation submitted by the state. The NWF submission and accompanying report suggests that US-regional and international transport of ozone to Utah is well simulated, while local contributions are likely underpredicted. The effects of an underprediction of local ozone contribution would overstate the relative role of international contributions in the context of a CAA section 179B demonstration. The same underprediction of local ozone contributions could understate the contribution of NWF emissions to ozone at monitors in other states.

As described in the Air Quality Modeling Final Rule TSD, the EPA performed air quality modeling using the 2016v3 platform which includes updates made in response to comments on the proposal modeling. The table below provides normalized mean bias (NMB) and normalized mean error (NME) model performance statistics at individual monitoring sites in the NWF for June through August for both the 2016v2 and 2016v3 modeling. The EPA v3 model performance information, provided in Table 3-25 is substantially improved compared to both the EPA v2 modeling and the Ramboll modeling submitted in the state's 179B demonstration. The data show that model performance improved when looking across all days and on just those days with MDA8 ozone greater than 60 ppb. Note that the statistics for the 2016v3 modeling are well within the range of the performance criteria for NMB (less than $\pm$15 percent) and NME (less than or equal to 25 percent) offered by Emery et.al. (2017). In contrast to EPA's 2016v3 modeling, the 2016 Ramboll modeling presented in Utah's 179B(b) petition cited by the commenters had average NMB and NME of -6 percent and 10 percent for all days in the period June through August and -12 percent and 13 percent for those days with observed MDA8 ozone greater than or equal to 60 ppb. In summary, model performance concerns for monitors in the NWF expressed by the commenters have been addressed in the EPA's 2016v3 modeling. The statistics for the updated modeling at the monitors in the table below are well within the range of performance criteria offered by Emery et.al. (2017) for NMB (less than ±15 percent) and NME (less than or equal to 25 percent).

Table 3-25

June - August MDA8 O3 Stats for All Days						
			2016v2 Proposal Modeling		2016v3 Updated Modeling	
Site ID	County	Site	NMB (%)	NME (%)	NMB (%)	NME (%)
490110004	Davis	Bountiful Viewmont	-6.8	10.9	0.3	9.5
490353006	Salt Lake	Hawthorne	-5.2	10.8	1.0	11.0
490353013	Salt Lake	Herriman	-12.5	13.2	-5.3	9.5
490450004	Tooele	Erda	-7.6	11.0	-0.4	9.3
490570002	Weber	Ogden	-7.7	10.6	-1.0	8.9
490571003	Weber	Harrisville	-12.5	13.5	-6.0	9.4

June - August Stats for Days with Obs MDA8 O3 ≥ 60 ppb						
			2016v2 Proposal Modeling		2016v3 Updated Modeling	
Site ID	County	Site	NMB (%)	NME (%)	NMB (%)	NME (%)
490110004	Davis	Bountiful Viewmont	-14.0	14.6	-6.8	9.2
490353006	Salt Lake	Hawthorne	-14.1	16.4	-8.1	11.1
490353013	Salt Lake	Herriman	-16.4	16.6	-9.3	10.9
490450004	Tooele	Erda	-15.9	16.7	-8.6	10.8
490570002	Weber	Ogden	-15.5	15.7	-8.2	9.8
490571003	Weber	Harrisville	-16.4	16.5	-9.4	9.9

Regarding San Antonio, the commenter misrepresents the treatment of uncertainty in the San Antonio case and presents a false equivalency between 179B analysis and what is required here. The San Antonio 179B demonstration was disapproved because it failed to provide a full retrospective analysis of what caused the area to fail to attain based on 2018-2020 monitoring data in the case of San Antonio, and not due to any one factor like model uncertainty. CAA section 179B requires that the area would have attained "but for" emission emanating from outside the US. The Agency's 179B guidance highlights that evidence will be more compelling when international contributions are large compared to U.S. contributions. Thus, the uncertainty in TCEQ's international contribution estimate of 2-3 ppb was interpreted within those specific contexts. In its determination, the EPA noted that TCEQ's model-predicted international contribution estimates were uncertain, in part because there is less reliable data on non-U.S. emissions, particularly in Mexico and China, compared to emissions in the U.S.

Furthermore, the EPA noted that TCEQ's assertion of a 2 to 3 ppb contribution from international sources is very close to the amount needed to reduce the 72 ppb model-projected design value to below the NAAQS, as required in a "but for" 179B analysis. In this regard, given the particular circumstances of the 179B analysis for San Antonio, the uncertainties in the determination of international contributions coupled with the 2 ppb amount of nonattainment, and several other factors discussed in EPA's TSD for its action on TCEQ's 179B Demonstration for San Antonio,[73] the EPA found the estimated international impact too small to confidently conclude that the area would have reached attainment but for international emissions. In short, the relevance of "uncertainty" as applied in 179B determinations is not relevant or comparable to the modeling analyses in this action. *See Wisconsin*, 938 F.3d at 323-24 (contribution analysis under the good neighbor provision is not a but-for test).

3.5.3.14 Wisconsin

Comment:

Commenter (0369) states that upwind states (Illinois, Michigan, Indiana, Missouri, Ohio) have a considerable impact on Wisconsin's ozone pollution, which limits how much Wisconsin can affect ozone attainment, especially along the Lake Michigan shoreline. According to the commenter, ozone precursor pollutants blow over Lake Michigan which has ideal conditions for ozone formation which can then be transported to Wisconsin shoreline counties. The EPA modeling finds that out of state pollution contributes 42 – 48 percent to Wisconsin ozone average DV and that two states (Illinois and Indiana) contribute more to Wisconsin's ozone pollution than our own state. The commenter finds fault with the EPA's inclusion of certain monitors for the state contribution analysis (only 397 monitors included out of 948 modeled monitors). Specifically, the EPA should have included monitored sites that are currently measuring nonattainment for years 2020 and/or 2021. The commenter is skeptical that the monitors in Door and Ozaukee counties, which are currently out of attainment, will achieve attainment by 2023. For example, Ozaukee has been out of attainment of the 2015 ozone NAAQS every year since 2018. Not currently including nonattainment monitors projected to achieve attainment limits the potential pollution decreases from this FIP. Additionally, Sheboygan was modeled to be out of attainment in 2023 but not included in the contribution analysis. All monitors currently out of attainment and modeled to be out of attainment in 2023 should be included in the interstate transport analysis.

[73] Technical Support Document Evaluating the Clean Air Act Section 179B Demonstration for the San Antonio Marginal Ozone Nonattainment Area, December 2021 (Docket ID: EPA-R06-OAR-2020-0168)

Response:

The table below provides the 2021 and preliminary 2022 DVs, the 2021 and 2022 preliminary 4th High MDA8 ozone concentrations, and the projected 2023 average and maximum DVs for monitoring sites in Wisconsin along or near the shoreline of Lake Michigan. The definitions of nonattainment and maintenance-only receptors based on monitoring and modeling and the maintenance-only receptors based violating monitors are described in Section IV.D in the preamble of this final rule. Based on the receptor definitions, the EPA has identified five of these monitors as nonattainment or maintenance-only receptors, as indicated in the table below. The EPA has calculated average contribution metric values for each of the 13 monitoring sites in this table. The contributions from each upwind state to each of these monitoring sites can be found in the file "Final GNP O3 DVs_Contributions.xls"

Table 3-25

Site ID	County	2021 DV	2022[a] DV	2021 4th High	2022[a] 4th High	2023 Avg DV	2023 Max DV	Receptor Status
550290004	Door	70	**73**	70	**75**	65.2	65.4	-
550590019	Kenosha	**74**	**75**	**79**	70	70.8	**71.7**	*Maintenance-Only*
550590025	Kenosha	**72**	**73**	**72**	**71**	67.6	70.7	*Violating Monitor*
550610002	Kewaunee	64	67	68	**72**	62.7	63.3	-
550710007	Manitowoc	68	**73**	70	**81**	65.9	66.8	-
550790010	Milwaukee	61	63	66	65	59.3	60.9	-
550790085	Milwaukee	70	**73**	**72**	**74**	66.5	67.7	-
550890008	Ozaukee	**71**	**72**	**72**	**72**	65.2	65.8	*Violating Monitor*
550890009	Ozaukee	70	**71**	**73**	**71**	66.7	67.4	-
551010020	Racine	**73**	**75**	**78**	70	69.7	**71.5**	*Maintenance-Only*
551170006	Sheboygan	**72**	**75**	**73**	**77**	**72.7**	**73.6**	*Nonattainment*
551170009	Sheboygan	65	69	66	**71**	63.6	64.5	-
551330027	Waukesha	65	68	70	69	59.7	60.0	-

[a.] Data for 2022 are preliminary and reflect data reported to the EPA as of January 3, 2023.

In addition, the EPA has considered all monitoring sites nationwide in its analysis of interstate transport. In Step 1 the EPA projected 2016 base period average and maximum DV to 2023. In total there were 1194 monitoring sites with valid base period DVs that could be projected to 2023. As recommended in the EPA's modeling guidance, 2016 modeled ozone concentrations were examined to identify those monitoring sites for which there were at least 5 days with model predicted MDA8 ozone concentration of 60 ppb or higher. Projected 2023 DVs are calculated for those monitoring sites that meet this criterion. That is, as recommended in the EPA's modeling, projected DVs are not calculated for those monitoring sites for which there are fewer than 5 days with MDA8 concentrations at or above 60 ppb. As a result of applying this criterion, we project 2023 DVs for 92 percent of the monitoring sites with valid base period measured data.

Comment:

Commenter (0338) states that on March 10, 2022, the EPA proposed to redesignate the Chicago nonattainment area to attainment with the 2008 ozone NAAQS. In so doing, the EPA's comments indicate additional reductions in Wisconsin are not necessary for the area to maintain compliance with the 2015 ozone NAAQS:

> While modeling is not required, Illinois cited photochemical modeling performed by EPA and LADCO in support of the interstate transport "good neighbor" provision of the CAA for the 2015 ozone NAAQS. These modeling results project the highest 2023 average DVs to be 0.0662 and 0.0668 ppm, well below the 2008 ozone NAAQS. Compared to actual monitored 2009 - 2013 average DVs, both sets of 2023 modeling results show large decreases in ozone concentrations, especially in the heart of the urban area and at the critical monitors at the north of the nonattainment area along the shore of Lake Michigan. These results provide evidence that ozone concentrations will continue to decrease across the entire nonattainment area.

Commenter (0338) notes the quoted paragraph above indicates that ozone levels are predicted to be significantly below the 2015 ozone NAAQS in 2023. Thus, Wisconsin pulp and paper mills do not need to obtain additional NO_X reductions because additional reductions are unnecessary for the Chicago area to comply with the 2015 ozone NAAQS. As proposed, the EPA's FIP would result in overcontrol of sources in Wisconsin.

Response:

The EPA disagrees that there is any meaningful conflict between the air quality projections in this action and certain observations the Agency made in a footnote to a proposed action on March 10, 2022. In that notice, the EPA proposed to find that the Illinois portion of the Chicago-Naperville, IL-IN-WI area is attaining the 2008 ozone NAAQS. 87 FR 13668 (March 10, 2022). That action only applies to the 2008 ozone NAAQS. However, the EPA noted in that proposal that "while modeling is not required" to support that action, there was modeling by the EPA and LADCO suggesting that average DVs in 2023 may be as low as around 66 ppb. *Id.* at 13679 n.5. This observation was not necessary to support that proposal, and the Agency did not cite to or otherwise explain the basis for the statement in this footnote. However, this appears to have been in reference to the EPA's older modeling of 2023, which has of course been updated in the 2016v2 modeling used at proposal and the 2016v3 modeling used at final, both of which now project that ozone levels in the Chicago area will remain above the 2015 ozone NAAQS in 2023. In fact, when the EPA finalized the 2008 NAAQS action, it made no further reference to that older modeling as a basis for its action or otherwise, and in response to adverse comments highlighting the EPA's updated transport modeling, we acknowledged: "EPA's ozone transport modeling indicates that, barring further emissions reductions, this area will continue to have difficulty attaining or maintaining the 2015 NAAQS in 2024." 87 FR 30821, 30826 (May 20, 2022). Subsequently, in the EPA's final "Determinations of Attainment by the Attainment Date" (DAAD) rule for the 2015 ozone NAAQS, the EPA found that the Chicago-Naperville (IL-IN-WI) nonattainment area had failed to attain the NAAQS and had DVs of 79 ppb, 77 ppb, and 76 ppb for the 2018-2020 period. 87 FR 60904 (Oct. 7, 2022). As such, the EPA reclassified the area to Moderate nonattainment, and that area is now subject to a January 1, 2023, deadline among other things to submit a SIP submission revision implementing RACM/RACT. *Id.* at 60900.

Consistent with the information presented by the EPA in these final actions in May and October of this year, the EPA's latest ozone transport modeling indicates that this area will continue to have difficulty attaining or maintaining the 2015 ozone NAAQS in 2023. Further, the EPA's modeling of the contributions to that ongoing air quality problem used in this action further indicates that these elevated ozone levels are due in part to the emissions of ozone-precursor pollutants transported from upwind states. Therefore, the EPA disagrees with commenters that our analysis in this action conflicts with other EPA actions.

The EPA's assessment of overcontrol for all receptors can be found in preamble Section V.D and in Section C.3 of the Ozone Transport Policy Analysis TSD. As described in preamble Section IV, the EPA finds Wisconsin linked in 2023. However, based on updates to both the EPA's emissions inventory and air quality modeling due to commenter input, the EPA's final rule analysis shows no linkage between Wisconsin and downwind receptors in 2026. Therefore, the EPA is not finalizing any additional stringency levels for Wisconsin in 2026 (*i.e.*, no non-EGU mitigation measures or EGU SCR mitigation measures).

The table below provides the 2021 and preliminary 2022 DVs, 2021 and preliminary 2022 4th High MDA8 ozone concentrations, and the 2023 projected average and maximum DVs for the three monitoring sites that the EPA has identified as receptors in the Chicago area based on the air quality modeling for this final rule. The data indicate that all three receptors are measuring nonattainment based on the 2021 and preliminary 2022 DVs and these receptors have measured 4th Highs that exceed the NAAQS in 2021 and/or 2022, based on preliminary data. In addition, as shown in the Air Quality Modeling Final Rule TSD, Wisconsin is projected to contribute above the 1 percent of the NAAQS screening threshold to each of these receptors in 2023. Thus, based on current measured and model projected DVs and contribution data, the EPA disagrees with the commenter that no additional emissions reductions are needed in Wisconsin to help Chicago area receptors attain the NAAQS.

Table 3-26

Site ID	County	Receptor	2021 DV	2022 DV	2021 4th High	2022 4th High	2023 Avg DV	2023 Max DV
170310001	Cook	Alsip	71	72	68	73	68.2	71.9
170314201	Cook	Northbrook	74	74	75	70	68.0	71.5
170317002	Cook	Evanston	73	74	78	71	68.5	71.3

Comment:

Commenter (0316) states the Kohler-Andrae monitor in Sheboygan County (monitor ID: 5511710006) is not used in EPA's calculations to determine states that contribute at least 1 percent of 70 ppb to downwind sites. The commenter indicates that this is historically one of the highest violating monitors in the Great Lakes region and asserts that it should be included in the contribution calculations for upwind states. The commenter states that Kohler-Andrae's omission is based on EPA's reliance on modeling that significantly underpredicts ozone concentrations along Lake Michigan, especially at the Kohler-Andrae monitor. The commenter believes that the EPA should include the Kohler-Andrae monitor to accurately calculate the contribution from upward states to the area.

Commenter (0324) states that the EPA's application of its contribution metric removes monitors that should be included in the transport rule, including the Sheboygan Kohler-Andrae monitor. The commenter relates that after identifying nonattainment and maintenance receptors at Step 1, the EPA applies a contribution metric that removes some of these monitors from further analysis, including the Sheboygan Kohler-Andrae monitor. According to the commenter, monitors that should be evaluated for transport implications according to the 4-step interstate transport framework process are not further considered in the rule. The commenter states that the EPA should provide a more complete explanation of why using this metric is necessary and how it intends to ensure the controlling monitor in all areas is considered in future analyses. To address this issue in this rule, the commenter suggests that the EPA change its procedures to ensure that any receptor it identifies at Step 1, including Sheboygan, remain in the rule, no matter what the contribution metric results might indicate.

Commenter (0758) says that Wisconsin's Lake Michigan shoreline sees approximately 45 percent of pollution come from out of state. Out of state contributions to Wisconsin shoreline counties' nonattainment and maintenance problems primarily come from other states in the region including Ohio, Indiana, Illinois, Missouri, and Michigan, but also from as far away as Texas. For example, Kenosha, Wisconsin's two nonattainment monitors are overwhelmingly impacted by transported ozone emissions. The state of Wisconsin contributes only 2.82 and 6.06 ppb to the two Kenosha monitors. By contrast, Illinois contributes 18.55 and 18.13 ppb and Indiana contributes an additional 7.10 and 6.60 ppb. And while EPA has included Kenosha (and Racine, Wisconsin) counties in its source-receptor modeling for this proposed rule, it has disregarded other shoreline counties in nonattainment that also experience transported as well as local air pollution contributions. Sheboygan County, as shown in Table II.1 supra is in marginal nonattainment of the 2015 standard. Recent trends do not show ozone levels decreasing but instead remaining steadily in nonattainment. While some of that nonattainment can be attributed to sources in the county (just as for other counties in the state), Sheboygan, like other lake-fronting counties, experiences transported ozone from out of state as well. However, it is not included in the EPA's modeling for this proposal, despite experiencing transported ozone over the lake similar to the other more southerly counties in the state.

Commenter (0307) argues the riparian placement of the Kohler Andrae monitor, unique meteorological and geographical features of the Lake Michigan shoreline, and the transport of ozone and ozone precursors along the lakeshore from upwind states significantly influences the readings at this monitor. The Kohler Andrae monitor has historically measured the highest ozone concentrations in the state, if not the entire Midwest, even though in-state sources of emissions contribute less than 12 percent of the measured ozone. Sheboygan County sources contribute approximately 2 percent to the ozone measured at the monitor. See Lake Michigan Air Directors Consortium, "White Paper: Lake Michigan Ozone Study 2017." LADCO source apportionment modeling studies suggest that Wisconsin contributes to less than 10 percent of the ozone at Sheboygan (Figure 5), significantly limiting the state' s options to reduce ozone concentrations at this site" (Page 7).

Commenter (0307) continues, there are no effective options for Sheboygan County to get the Kohler Andrae monitor to attainment due to the overwhelming contribution from upwind states. Source apportionment modeling shows five states (Illinois, Indiana, Michigan, Missouri, Texas) contribute about 40 percent (approximately 28 ppb) of the NAAQS standard value at the Kohler Andrae monitor (see EPA' s 3/27/18 memo), with Illinois and Indiana being by far the dominant contributors. The Kohler Andrae monitor is not properly sited to assess contributions from the City of Sheboygan metropolitan area. According to the EPA's guidance on monitoring site selection, "For regulatory compliance, the principle objective is to measure the ozone concentration in the high population density areas and the maximum downwind concentration from the urban region." The Kohler Andrae monitor does not meet these objectives, but the Haven monitor does, and it measures attainment. The Kohler Andrae monitor measures ozone transported into the county from upwind sources (88+percent from out-of-state) and there are no actions Sheboygan County can take to get the Kohler Andrae monitor to measure attainment for the 2015 Ozone NAAQS. Without a proper analysis of how upwind emissions impact the Kohler Andrae monitor, it is not possible to accurately plan for attainment in Sheboygan County (and the state of Wisconsin.

Response:

The EPA has calculated contributions in 2023 and 2026 from upwind states to the Sheboygan Kohler Andrae monitoring site based on the 2016v3 air quality modeling performed for this final rule. The contributions from individual states to this site are provided in the Air Quality Modeling Final Rule TSD and in the file “Final GNP O3 DVs_Contributions.xls,” which can be found in the docket of this final rule.

3.5.3.15 Wyoming

Comments:

Commenter (0315) says most of the NO_X emissions sources in Wyoming, to which the proposed rule would apply, are several hundred miles from the Colorado NFR where ozone exceedances occur. Most of these sources are also not directly upwind from the NFR (prevailing winds across southern and central Wyoming are from the west-southwest). The modeled impacts on Colorado receptors are therefore entirely false. Requiring additional controls on sources distant from, and not upwind from the high Colorado receptors would most likely have no real impact on Colorado nonattainment.

Commenter (0547) believes that Wyoming is not appropriately linked to Colorado. According to the commenter, the EPA overestimates the contribution of Wyoming EGUs and the impact of imposing extremely costly controls when determining Wyoming’s good neighbor obligations. Additionally, the commenter states that the EPA does not appear to take into account the reductions from the enhanced trading program. Furthermore, the commenter states the EPA’s approach fails to appropriately quantify Wyoming’s contribution to ozone concentrations at downwind receptors. Wyoming’s predicted contribution from EGUs in 2026 is very small—comprising of less than 10 percent of Wyoming's total contribution to the Denver-Chatfield receptor, and one-tenth of the 1 percent of the NAAQS threshold.

Response:

As explained in Section IV.F of the preamble, the EPA is deferring action at this time for Wyoming. Therefore, the EPA will not address the part of the comment asserting Wyoming is not linked to Colorado. In general, however, the EPA does not agree that the EPA's contribution analysis is not scientifically sound. The EPA disagrees with the comment that suggests ozone precursor emissions cannot impact receptors several hundred miles away. The EPA addresses comments related to the trading program in Section VI.B of the preamble and Section 5.2 (Regulatory Requirements for EGUs).

3.6 Step 2 Contribution Threshold

Comments:

Commenters (0341, 0372, 0396, 0400, 0500, 0514, 0513, 0541, 0798, 0547) refer to EPA's August 31, 2018, memo and notes the 1 ppb threshold is reasonable, is less subject to error and should be used by the EPA as the trigger for significant contribution. Commenter (0400) states EPA should address emissions in upwind states modeled between 0.70 ppb to 0.99 ppb in a different manner.

Commenters (0341, 0424) states EPA's use of a 1-percent-of-NAAQS threshold ignores the limits of the capability of the Agency's air quality modeling techniques – and of ambient monitoring – to meaningfully detect and measure ambient-air contributions at the extremely low levels represented by 1 percent of current or possible future NAAQS. The numerical values that result from application of EPA's one-percent contribution – in this case, 0.70 ppb, to link upwind states to downwind receptors projected by the EPA to be in nonattainment of, or to have problems maintaining attainment of, the 2015 ozone NAAQS – are so low that they are likely below the detection capability of existing modeling and measurement tools.

Commenter (0396) states EPA's decision to use a 1 percent threshold rather than a 1.0 ppb threshold is arbitrary and capricious because EPA has failed to give due consideration to important aspects of the issues that were raised in Oklahoma's transport SIP, the explanation offered by the EPA justifying their rejection of the use of a 1.0 ppb threshold was inadequate and appears to contradict EPA guidance that remains in effect, and there is no unambiguous statutory basis for this threshold. As Oklahoma explained in its comments on the proposed disapproval of Oklahoma's transport SIP, a 1 percent threshold was appropriate when there were many EGUs that were decades old that had not been equipped with simple, cost-effective technology, because a larger threshold would mitigate the possibility that increased emissions from nonparticipating EGUs would negate the reductions achieved by participating states. Exclusive reliance on that threshold is no longer warranted and EPA should recognize that the current proposal departs so significantly from the earlier rules addressing interstate transport of ozone precursors that the flexibilities offered in EPA guidance are necessary adaptations to the current situation. The commenter notes equity or EPA staff difficulties in implementation are also not valid reasons for rejecting a 1.0 ppb threshold because EPA has no statutory interest in maximizing the number of states it can subject to Step 3 of the analysis. The EPA's statutory role is to achieve attainment, not to maximize the number of states and sources impacted by regulation or to make it easier for its own staff to maximize regulations. To reject a 1.0 ppb threshold, EPA needs to demonstrate that it is not possible to achieve attainment at that threshold.

Commenter (0398) disagrees with EPA's proposal that a state with a statewide linkage just above EPA's arbitrary 1 percent threshold to a downwind receptor can reasonably be required to implement the same magnitude of controls as a state with sources contributing a higher percentage of emissions to the same downwind receptor. This is especially so when the model's mean error is greater than the linkage threshold, and when compared to a linkage considerably greater than the model's mean error, the linkage would still exist even when accounting for the mean error (*i.e.*, linkage is greater than Climate Region ME + 0.7 ppb). This is not the purpose of the good neighbor provision and is blatant over-control on EPA's part. It is over-control for not only Tier 2 non-EGUs, as EPA has itself stated, but also for any non-EGU (or EGU, for that matter) in Arkansas, until the necessary analysis is done to demonstrate a significant contribution from any one or more of these sources. EPA's methodology does not address the specificity of the Transport Rule's program framework under the CAA, which necessitates a more detailed look at individual sources and robust analyses to determine whether these sources are significantly contributing to downwind monitors that are in nonattainment areas. The emissions reductions expected from obligations proposed for Arkansas's EGU and non-EGU sources impact the monitors linked to Arkansas so insignificantly that benefits from those controls could be cancelled out with but a few added commutes through the area. The commenter states it does not find EPA's proposed FIP to be reasonable or equitable for Arkansas, and the state is being required to compensate for emissions that are either beyond EPA's near-term ability to control (*i.e.*, mobile sources) or result from in-state Texas point and area sources.

Commenter (0510) provides general support for the 1 percent contribution threshold.

Commenter (0541) states for the purposes of determining attainment, the EPA truncates data to the ones, making the limit 70.9 for a 70 ppb limit; however, the EPA concludes that a 0.70 ppb contribution is significant. In addition to the incongruence between the significance threshold and attainment determination, the EPA's Air Quality Model does not address the uncertainty associated with determining state contributions to downwind receptors. Rather, the EPA addresses only the uncertainty with determining nonattainment for individual monitors. None of the statistics the EPA calculates gives confidence that the model can determine whole number contributions, let alone contributions to two decimal places. The mean error in the Southeast climate region, including Alabama, is 6.1 ppb and in the South climate region, including Texas, is 9.1 ppb. It is inappropriate to use a significance threshold to one-tenths precision when NAAQS are truncated to whole numbers and the model used has uncertainty of up to +/- 9 ppb for monitors, yet the EPA has not addressed the impact of similar uncertainty when modeling state contributions.

Commenter (0547) states, in addition to the diversion from 2018 memo, the EPA itself acknowledges that the 1 percent threshold was previously used for the 1997 ozone NAAQS and in SIP approvals more than ten years old. The commenter notes it is disjointed for the EPA to rely on a threshold for this rulemaking it found appropriate nearly a decade ago, while at the same time concluding an alternative threshold it developed only four years ago is no longer appropriate based on recent "experience." the EPA suggests allowing states to use a 1 ppb threshold "would allow certain states to avoid further evaluation" at Step Three, which can create "significant equity and consistency problems among states." 87 Fed. Reg. at 20,073. The commenter believes this reasoning is flawed, as any threshold fundamentally causes some states to proceed to Step Three, and other states to be left out of the rulemaking altogether. Moreover, the EPA's suggestion that the interstate transport rule (and therefore the contribution threshold) must be consistent across the states, is undercut by the "great flexibility accorded the states under the Clean Air Act," including their development of their SIPs. Ultimately, the commenter believes EPA has not adequately explained why the 1 ppb threshold is no longer appropriate in this rulemaking.

Commenter (0764) states the proposal fails the second test of overcontrol: the expected ozone improvements are overcontrol because the 1 percent NAAQS screening threshold is not supported for Arkansas, Arkansas linkages resolve at Step 1, not requiring tier 2 reductions resolves EPA's potential overcontrol problem, and in any event - there is no climate exception for overcontrol.

Commenters (0519, 0764) add the EPA is making control decisions based on 1 percent of the standard when the mean error is roughly 10 percent of the standard. Furthermore, as stated by MOG in its comment: The numerical values that result from application of the EPA's one-percent contribution ... are so low that they are likely below the detection capability of existing modeling and measurement tools. For that reason, the EPA lacks a reasonable basis to conclude that a one-percent-of-NAAQS threshold can be deemed to reflect a "measurable contribution" to downwind nonattainment and maintenance problems, as required by the D.C. Circuit. [Michigan, 213 F.3d at 684.]

Commenter (0398) notes the EPA's modeling is not precise or accurate enough to establish that emissions from the state of Arkansas significantly contribute to nonattainment at the receptors located in Texas that the EPA "links" to Arkansas and provides technical reasoning. The EPA's Air Quality Modeling Proposed Rule TSD states that the mean error of the model is between 6.0 and 7.0 ppb for all days during the ozone season (6.6 ppb for the 'South' climate region, which includes Arkansas, Oklahoma, Texas, Kansas, Louisiana, and Mississippi). This mean error is almost ten times or a full order of magnitude more than the 0.7 ppb figure that constrains the EPA's own arbitrary decision about what constitutes a "significant contribution" for Arkansas as a whole. Further, the EPA's Air Quality Modeling Proposed Rule TSD also points out that the mean error is "less than 20 percent" in the South climate region. Although EPA's Air Quality Modeling Proposed Rule TSD also states that its model tends to under predict concentrations above 60 ppb, the results for the South climate region, shows that the mean error consistently outweighs the mean bias, *i.e.*, the margin of error is consistently greater than the bias prediction of the model. The EPA justifies its reliance on its model stating "the ozone model performance for the CAMx 2016fj (2016v2) simulation are within or close to the ranges found in other recent peer-reviewed applications." However, just because the EPA's current model shares the same degree of error as other peer-reviewed models does not mean that it is suitable to establish a “significant contribution” at the 0.7 ppb level that the EPA has attempted to set with its analysis of Arkansas’s emissions.

Commenters (0279, 0317, 0519, 0764) explain to avoid an illegal over-control situation, the EPA’s modeling must be precise and accurate enough to confidently predict concentration differences of 0.7 ppb. Yet, the EPA’s Air Quality Modeling Proposed Rule TSD, states that the mean error of the model is between 6 and 7 ppb for all days during the ozone season, almost ten times or an order of magnitude more than the 0.7 ppb figure that constrains the EPA’s own arbitrary decision about what constitutes a “significant contribution” for the state of Arkansas as a whole.

Commenter (0519) states the EPA determined in its proposed FIP that Oklahoma's largest contribution to downwind air quality problems is 1.19 ppb in 2023 and 0.72 ppb in 2026, meaning that Oklahoma exceeds the EPA's 0.70 ppb linkage threshold by 0.49 ppb in 2023 and 0.02 ppb in 2026. These calculated values are less than 1 percent of the NAAQS standard, which is only a fraction of the mean error. Similarly, in 2023, the highest maximum DV at a linked receptor is 72.4 ppb, while the highest average DV is 70.4 ppb, meaning that the EPA concluded that these downwind receptors would experience air quality problems in 2023 by a threshold of less than 5 percent of the NAAQS, which is only half the mean error.

Commenter (0279) references the Air Quality Modeling Proposed Rule TSD: Appendix A. For both the Southeast (Alabama) and the South (Texas) regions there is bias and error in the model ranging from ±2.9 to 6.1 ppb in the southeast and ±7.8 to 9.1 ppb in the south. This bias/error is considered acceptable when evaluating how well the model replicates monitor concentrations. Given the magnitude of the acceptable bias/error, it seems illogical that such a small threshold could adequately represent, with true accuracy, impacts from states hundreds of miles away.

Commenter (0317) argues the EPA’s modeling is not precise or accurate enough to establish that emissions from the state of Arkansas significantly contribute to nonattainment or interfere with maintenance at the receptors located in Texas that the EPA “links” to Arkansas. The maximum Arkansas contribution in 2023 at a downwind nonattainment receptor is 1.00 ppb and the maximum Arkansas contribution at any downwind maintenance receptor is 1.39 ppb. Arkansas’s predicted contributions are even smaller in 2026, and EPA emissions from Arkansas will only be “linked” to a single maintenance receptor in Brazoria County, Texas at this time, with a predicted Arkansas contribution of 1.30 ppb to this receptor.

Commenter (0541) adds the mean error in the Southeast climate region, including Alabama, is 6.1 ppb and in the South climate region, including Texas, is 9.1 ppb. It is inappropriate to use a significance threshold to one-tenths precision when NAAQS are truncated to whole numbers and the model used has uncertainty of up to ± 9 ppb for monitors, yet EPA has not addressed the impact of similar uncertainty when modeling state contributions.

Commenter (0542) states according to EPA’s flawed models, which include emissions from retired resources, NO_X emissions from Mississippi contribute approximately 1.6 percent of the ozone exceedances in Denton and Harris Counties in Texas. The models estimate that emissions from Mississippi contribute 1.04 ppb and 1.4 ppb to the two counties, respectively. To effect relief for these downwind receptors, Mississippi is being required to reduce its overall NO_X budget by approximately 61 percent. Given the relatively high mean error accuracy of the model (± 6.6 ppb), the EPA cannot demonstrate that the modeled exceedances attributed to Mississippi are even, in fact, occurring. The proposed reduction on the Mississippi NO_X budget is equivalent to attacking an ant with an anvil.

Commenter (0798) states that the EPA compared the CAMx model used by the EPA to evaluate state contributions to linked receptors with actual monitoring data for each such receptor to evaluate the accuracy and precision of the CAMx model. For example, the result showed a standard deviation of 8ppb for modeling at the relevant Brazoria County, Texas receptor, and only accounted for 37 percent of observed variation at the receptor. Although EPA claims this is on par with other CAMx models so as to not invalidate use of CAMx for the proposed rule, the imprecision of the CAMx modeling should be taken into account when EPA sets its levels of what contribution amount to consider to be "significant" for purposes of determining the applicability of the proposed rule.

Response:

The EPA has addressed these comments in Section IV.F. in the preamble of this final rule.

3.6.1 Applicability of 1 Percent Threshold for Specific Upwind States and Downwind Receptors

Comments:

Commenter (0367) is in support of the 1 percent threshold and states that the EPA should continue to use 1 percent of the NAAQS as the screening threshold at CSAPR Step 2 and should rescind its 2018 alternative thresholds memorandum.

Commenter (0405) states that according to Alpine Geophysics analysis, Minnesota does not significantly contribute to the two maintenance monitors in Illinois when the threshold contribution is returned to EPA's longstanding threshold of 1 ppb. Using 1 percent arbitrarily changes what constitutes a significant contribution each time the NAAQS changes. The significance of a state's contribution should be based on an absolute value (1 ppb) to avoid the absurd result that a state, like Minnesota, could be deemed significant based on percent with the same or even a declining absolute ppb contribution to downwind receptors. Minnesota is the only upwind state with linkages to all Illinois maintenance monitors that would be explicitly unlinked should the threshold be returned to 1 ppb.

Commenter (0428) states that pollutant sources, methods of dispersion, and types of affected areas in the West are quite different from those in the eastern United States. The WESTAR region is complex in terms of air quality regulatory jurisdictions with interlinked responsibilities. In addition, a vast amount of the region are federal lands and federal agencies, including EPA, have primary responsibility to manage and control air pollution sources on those lands and from sectors the CAA has reserved for federal control. The West needs additional and ongoing research on background, interstate, and international ozone. Therefore, the commenter requests reconsideration of the 1 percent threshold for significant contribution for interstate ozone transport obligations such as applied in the proposed FIP. The commenter strongly supports improvements to ozone and related air quality indicators across the WESTAR region at both urban and rural locations. The proposed FIP is an inappropriate regional solution for a small number of affected sites hundreds of miles apart across complex terrain. The proposed FIP proposes what appears to be a narrow list of sources but is actually open-ended in terms of the state-regulated sources. The commenter also notes the problematic situation for contributions from international sources and how decisions are made by the EPA about Exceptional Event data flagging for increasingly non-rare major air pollution episodes. Smoke impacts from wildfire are frequent and normal at this point and continuing for decades, accelerated by climate change.

Commenters (0518, 0539, 0798) state the EPA has not justified its basis for asserting the 1 percent threshold is the only valid approach. Commenter (0539) asserts the EPA has ignored the viability of using additional potential triggers expressed in concentrations, either 1 part-per-billion (ppb) or 2 ppb, as the EPA evaluated in August 2018 Memorandum. While the EPA is proposing that Minnesota exceeds the one-percent-of-NAAQS threshold at the two identified Illinois maintenance monitors, Minnesota would not exceed a 1 ppb concentration threshold if the EPA instead used a concentration-based threshold to assign state culpability, and Minnesota would no longer be identified as a significant upwind contributor.

Commenter (0518, 0519) states the screening threshold the EPA applied failed to follow Agency guidance and lacked a sufficient technical basis for the threshold selected. The EPA failed to explain its decision to depart from its own agency procedures in which a peer-reviewed analysis found 1 ppb was the appropriate screening threshold for evaluating whether a state contributes significantly to downwind emissions under the 2015 ozone NAAQS.

Commenter (0518) also states that the use of a 1 ppb significant ozone contribution threshold instead of 1 percent of the NAAQS has an effect on the number of states identified in Step Two as having a significant contribution. The following states had 2023 ozone contributions between the 1 percent of the NAAQS and 1 ppb thresholds so were included in the proposed rule, even though applying the EPA’s peer-reviewed analysis they had an “insignificant” contribution to an ozone DV at a downwind state nonattainment/maintenance receptor: Alabama (0.88 ppb), Kentucky (0.88 ppb), Minnesota (0.97 ppb), Nevada (0.89 ppb), Tennessee (c ppb) and Wyoming (0.81 ppb). In addition, the following states have 2026 ozone contributions between the 1 percent of the NAAQS and 1 ppb thresholds: Mississippi (0.90 ppb), Oklahoma (0.72 ppb) and Oregon (0.98 ppb).

Commenter (0519) also states in changing the linkage threshold, the EPA does not analyze or account for any reliance interests. Many states, including Oklahoma, developed SIP submissions based on the EPA's guidance, expending significant resources in conducting complex technical analyses applying the l ppb threshold that the EPA endorsed in its August 2018 Memo. The EPA makes no acknowledgement of these reliance interests in imposing a 0.70 ppb threshold in its proposed FIP.

Commenter (0798) states Minnesota is not having a significant impact on downwind air quality. Minnesota was identified as a non-significant contributor (below 0.7 ppb) to any ozone monitors in the 2018 modeling performed by both the EPA and LADCO. Minnesota’s original submittal should have been approved based on contribution information available from both the EPA and LADCO at that time. While the EPA now maintains that it has found contributions in excess of 0.71 ppb at two monitors, the EPA's position that this alone is sufficient to subject Minnesota to regulation is based on an overly-conservative assumption that a 1 percent threshold is sufficient to justify regulation of downwind ozone impacts. The commenter also asserts that the EPA's decision to regulate Minnesota based on a maximum modeled contribution of 0.97 ppb rather than the EPA's guidance threshold of 1 ppb also is particularly troubling because the model EPA is using lacks the consistency and accuracy needed to make such fine-grained distinctions. Rather, based on the EPA's own assessment in the Air Quality Modeling Proposed Rule TSD, "the regional mean bias of the model is +/- 5 ppb and the mean error is between 6 and 7 ppb on average for all days during the period May through September in each region."

Response:

The EPA has addressed these comments in Sections IV.F. & G. in the preamble of this final rule.

3.6.2 Consideration of Alternative Thresholds

Comments:

Commenter (0318) supports the use of a uniform contribution linkage threshold of 1 percent of the NAAQS level and opposes the alternative of 1 ppb. The commenter further recommends EPA provide additional context on the extent of state-level upwind contributions to downwind ozone problems by providing a state's percent contribution based on the modeled concentration of anthropogenic emissions and anthropogenic emissions totals within only the affected states (upwind and downwind). Specifically, the commenter suggests that modeled concentrations associated with background conditions, wildfires, and emissions in Canada and Mexico would be removed from the percent calculation. The commenter believes that this framing of percent contribution would provide additional context for the impact the contributing state has on downwind monitors by only looking at the ozone precursors that can be controlled in the covered states. According to the commenter, framing contribution percentages in this manner would also put nonattainment areas and contributing states on more equal footing, as nonattainment areas can only reduce ozone precursors from the anthropogenic emissions they control.

Commenter (0323) states the EPA correctly concludes at Step 2 that many upwind states contribute less than 1 percent to downwind problem areas and should not be subject to additional controls. However, the EPA's refusal to consider higher significance levels consistent with its own guidance is an arbitrary and capricious action that is a legal flaw in this proposed FIP. The commenter also notes the EPA's use of a 1-percent-of-NAAQS threshold ignores the limits of the capability of the Agency's air quality modeling techniques – and of ambient monitoring – to meaningfully detect and measure ambient-air contributions at the extremely low levels represented by 1 percent of current or possible future NAAQS. The commenter also reviewed the remaining eastern state nonattainment monitors as defined in the proposal and states should the significant contribution threshold be raised from 1 percent of

NAAQS (0.70 ppb) to a greater than 1.0 ppb limit, several states would have their contribution linkages broken to all monitors. Additionally, even with this increase in significant contribution threshold, each monitor in Connecticut would still have over 93 percent of the original 1 percent contribution, Wisconsin would still have over 96 percent of the original 1 percent contribution, and Texas monitors would have 89 percent of the original 1 percent contribution values associated from the remaining states. Should the threshold be raised to 2 ppb, the linkage from nine additional states (Arkansas, Maryland, Michigan, Mississippi, Missouri, Ohio, Texas, Virginia, and West Virginia) would be broken to all remaining eastern state nonattainment receptors with the majority of upwind contribution still captured by the remaining linked states.

Commenters (0331, 0437) encourage the EPA to use the 1 ppb significant contribution threshold. Commenter (0331) states EPA's use of a 1-percent-of-NAAQS threshold ignores the limits of the capability of the Agency's air quality modeling techniques – and of ambient monitoring – to meaningfully detect and measure ambient-air contributions at the extremely low levels represented by 1 percent of current or possible future NAAQS. The numerical values that result from application of EPA's one-percent contribution – in this case, 0.70 ppb, to link upwind states to downwind receptors projected by the EPA to be in nonattainment of, or to have problems maintaining attainment of, the 2015 ozone NAAQS – are so low that they are likely below the detection capability of existing modeling and measurement tools. For that reason, the EPA lacks a reasonable basis to conclude that a 1-percent-of-NAAQS threshold can be deemed to reflect a "measurable contribution" to downwind nonattainment and maintenance problems.

Commenter (0409) supports a 1 ppb threshold. The commenter also suggest the EPA could address emissions in upwind states modeled between 0.70 ppb to 0.99 ppb in a different manner. The EPA's model for 2026 shows modeled contributions between 0.70 ppb to 0.99 ppb for Kentucky, Missouri, Nevada, Oregon, and Utah to downwind nonattainment receptors. Using the EPA's modeling and assumptions, these states may have not been pulled into the proposed rule at all or may have become "unlinked" in 2026 – the year when the proposed FIP imposes stringent EGU requirements. In these states, the EPA's contribution threshold decision is impactful and very expensive, especially given only a 7 percent downwind benefit.

Commenter (0433) supports the 0.7 ppb threshold and recommends that the EPA consider adopting a methodology designed to obtaining further reductions from states with contributions above the 2.5 ppb threshold.

Commenter (0516) states EPA's modeling analysis overinflates upwind state contribution to downwind receptors. The 1 percent screening threshold EPA applied failed to follow Agency guidance and lacked a sufficient technical basis, resulting in a minimum of nine states (Alabama, Kentucky, Minnesota, Nevada, Tennessee, Wyoming, Mississippi, Oklahoma, and Oregon) where non-EGU sources should not be covered by the proposed regulation. The commenter also notes the EPA's deviation from the 2018 Memo and then requests the EPA apply a 1 ppb threshold.

Commenter (0547) states the EPA should reconsider its rejection of the 1 ppb contribution threshold, or alternatively, consider an alternative analysis at Step Three for states contributing less than 1 ppb.

Commenter (0554) references the 2018 memo and notes a threshold of 1 ppb is 1.4 percent of the ozone standard of 70 ppb, and therefore rounds down to 1 percent if truncated. Despite the fact that the 2018 analysis was based on the same principles as the 2011 analysis and was improved by use of a tighter range of options and more current data and modeling, the EPA now all but disavows it. While technically retaining the 2018 memo, the EPA has proposed to disapprove numerous state submissions that relied on the memo, claiming that those states should have somehow done more analysis than the EPA did itself in writing the memo, and asserting without explanation that consistency is needed across the country. The EPA also ignores the 2018 memo in its own over-control analysis for the proposed rule, focusing solely on its prior 1 percent (0.7 ppb) threshold instead of considering the 1 ppb threshold that the EPA determined to be an appropriate alternative based on a more recent and narrowly focused modeling analysis. In addition, the EPA has already determined in another context that two ozone DV that differ by less than 1 ppb are not statistically significantly different from each other, based on the statistical analysis use to define 1 ppb ozone as the Significant Impact Level (SIL) for the PSD program. The EPA's own demonstration that 1 ppb is not statistically significant confirms that 1 ppb is an appropriate de minimis threshold. Further discussion of this point is provided in the enclosed report from Ramboll evaluating the EPA modeling analysis underlying the proposed rule. The commenter suggests the 2018 Memo value (1 ppb).

Commenter (0504) states the EPA determined that a handful of steel facilities (and only two EAF steel producers) "significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS" based on modeling contributions to downwind receptors of as little as 0.01 ppb (0.014 percent). This amount is several orders of magnitude lower than that which can be measured at any of the EPA's designated ozone monitors and far lower than the values the EPA's own guidance would deem to be insignificant, trivial, or de minimis. The commenter refers to "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration ("PSD") Permitting Program" ("2018 SIL Guidance"). The SIL value the EPA's 2018 SIL Guidance recommended for the 2015 Ozone NAAQS is 1.0 ppb. Therefore, applying the descriptions the EPA used in the 2018 SIL Guidance, emissions that contribute less than 1.0 ppb toward the 2015 Ozone NAAQS are considered "insignificant," "de minimis," or "trivial." In contrast, the EPA's Non-EGU Screening Assessment purports to identify entire non-EGU industry sectors with dozens of emissions units as "significant contributors" to downwind receptors based on collective contributions of one-tenth to one-hundredth of the threshold that the 2018 SIL Guidance recommends for single sources.

Commenter (0758) states while the EPA uses a 1 percent threshold for determining if there is significant contribution to summertime ozone, the EPA appears to be using a 50 percent or more, that is upwind states would have to be the main cause, threshold for significant contribution for wintertime ozone. To the extent the EPA responds by saying that it did not mean that an upwind state has to be over 50 percent to be the main cause but it means some other value, the EPA has failed to explain its rationale.

Commenter (0798) also states, in addition to the diversion from 2018 memo, that 1 ppb is the significant digit for reporting ozone monitoring data under the NAAQS. And imprecision of EPA's modeling demonstrates that a significance threshold below 1 ppb simply cannot be justified since the model lacks the capability to distinguish impacts below that level. Finally, EPA has already determined that 1ppb represents the level at which a single facility presents a significant impact under the 8 hr Ozone NAAQS in the context of PSD permitting. In making the determination that 1ppb represents the significant impact level (SIL) for evaluating whether a given source may contribute significantly to any attainment issues with the 8 hr Ozone NAAQS, the EPA engaged in actual statistical analysis to find what "degree of change in concentration is, thus, indistinguishable from the inherent variability in the measured atmosphere and may be observed even in the absence of the increased emissions from a new or modified source" and determined that "changes in air quality within this range (*i.e.,* the relevant SIL) are not meaningful, and, thus, do not contribute to a violation of the NAAQS." By contrast, the EPA provides no analysis for why the various proposed significance screening levels in the proposed rule (0.7ppb for an entire state, and 0.01 for an entire industrial sector) represent a significant contribution with respect to air quality at downwind receptors.

Commenter (0509) states that according to the EPA's Statistical Analysis, Wyoming's Ozone Contribution is Not Statistically Significant. The EPA' s 2018 ozone statistical evaluation report presents compelling and sound technical arguments using powerful and robust statistical procedures to determine that two ozone DVs that differ by less than 1 ppb are not statistically significantly different from each other. The EPA has not provided a technical basis for changing course. The EPA' s proposed rule estimated that Wyoming contributes 0.81 ppb and 0.80 ppb, respectively, to the 2023 and 2026 ozone DVs at Chatfield. Therefore, Wyoming's ozone contribution to Chatfield, by the EPA's own "statistically significance test", is not statistically significant.

Response:

The EPA has addressed these comments in Sections IV.F. & G. in the preamble of this final rule.

3.7 The EPA's Alleged Deviation From 2018 Memoranda

Comments:

Commenter (0279) states that the most recent guidance documents discussing significance thresholds, issued in March and August of 2018, discuss significance thresholds, with the former allowing flexibility in determining significance, and the latter finding a significance level of 1 ppb as a sufficient threshold. Based on these documents, the significance threshold can be set at 1 ppb. There is also precedent for setting significance thresholds for ozone in the PSD program, which set the level at 1 ppb. Given the maintenance receptor identified in the latest round of modeling (January 2022) projects an average concentration of 70.4 ppb and a maximum concentration of 72.2 ppb in 2023, coupled with continuing reductions in Alabama point source NO_X emissions, the only emissions that Alabama can reasonably control, it serves that this is a justifiable argument for excluding Alabama as a significant contributor.

Commenter (0323) also states that the EPA's 2018 flexibility memos have become such an integral part of the development of good neighbor SIPs that the EPA is legally and ethically obligated to allow states and stakeholders the opportunity to meaningfully assess EPA's new regulatory perspectives and actions.

Commenters (0323, 0331) state the EPA proposed to disapprove 19 good neighbor SIP submittals using eight proposed rulemakings, including for Minnesota. Many of the 19 SIPs incorporated and relied upon the flexibilities articulated in the 2018 good neighbor SIP guidance memoranda. The EPA's 2018 flexibility memos have become such an integral part of the development of good neighbor SIPs that the EPA is introducing unnecessary and substantial additional analytical burdens to states that have already spent substantial effort in following these published flexibilities. In failing to maintain the option to use these potential alternative approaches to identifying maintenance areas within the regulated domain, the EPA continues to overburden upwind states that only contribute insignificantly to maintenance areas and would likely have lesser emissions reduction response requirements when linked to nonattainment monitors alone.

Commenters (0372, 0500) disagree with the Agency's decision and action to reverse its positions articulated in 2018 guidance in the Draft FIP, largely because so many states, including Kentucky, Alabama and Mississippi relied on the 2018 guidances to prepare their SIP. The commenters criticize the Agency, stating that there was no notice of this reversal of position, and as a result, states had no opportunity to respond to the EPA's change of policy by submitting or resubmitting revised SIPs.

Commenter (0382) states that not allowing states to use the 1 ppb standard is arbitrary and capricious. In the memo, the EPA explains that it is considering various screening thresholds because determining an appropriate threshold "is a critical component of designing and applying" the second step of the EPA's framework to address upwind state obligations, and "conclusions made with respect to one NAAQS are not by default applicable to another NAAQS." After finding that "the amount of upwind collective contribution captured using a 1 ppb threshold is generally comparable to the amount captured using a threshold equivalent to 1 percent of the NAAQS," the EPA noted that "it may be reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold." This decision contradicts the EPA's own factual findings. One of the EPA's reasons for requiring the 1 percent threshold is that, while the EPA may have previously recognized some "similarity" in the amount of upwind contribution captured between the 1 percent standard and the 1 ppb standard, the 1 ppb threshold loses more upwind contribution than the 1 percent threshold. The commenter also mentioned states' reliance on the August 2018 Memo.

Commenter (0397) states EPA issued 3 memorandums in 2018 and when conducting the 4-step interstate transport framework, Oklahoma's ozone transport SIP relied on flexibilities held out in the 2018 Tsirigotis Memos to demonstrate that Oklahoma is not linked to any problematic downwind receptor (Step 2 of the 4- step framework). In the proposed disapproval of Oklahoma's ozone transport SIP, the EPA rejected Oklahoma's justification offered in the transport SIP. Then, the EPA performed a new analysis, still following the 4-step interstate transport framework, but using updated data. Of particular importance to this process was the EPA's use of new emissions inventory data, specifically Version 2 of the 2016 Emissions

Modeling Platform (2016 v2 EMP). This data set was not available to states or the EPA at the time SIPs were due or at the time the EPA was statutorily required to act on SIPs. Using updated emissions inventory data and new modeling, the EPA identified only two receptors potentially impacted by Oklahoma emissions, one of which is entirely different than any originally identified. The updated, problematic receptors are in Denton County, Texas and Cook County, Illinois.

Commenter (0510) supports the 1 percent threshold and urges the EPA to revoke the 2018 guidance memorandum as it created another opportunity for upwind states to avoid controlling high-emitting sources.

Commenter (0517) states the EPA should honor the Peter Tsirigotis memos from March, August, and October of 2018 that Oklahoma used in the development of its I-SIP. These memoranda were held out to states as providing possible guidance for development of ozone transport SIPs, and states relied on these memos accordingly. The states relied in Good Faith on the flexibilities offered in the EPA memos, but the memos are not being honored by the EPA.

Commenter (0758) states the EPA should formally rescind its 2018 alternative contribution threshold guidance. First, the commenter strongly supports the EPA's observation that "consistency in requirements and expectations across all states is essential" in regulating emissions to address a regional air "emissions from an upwind state contribute significantly to nonattainment if the maximum contribution is at least 2 ppb, the average contribution is greater than 1 percent, and certain other numerical criteria are met". Second, the commenter disputes the Contribution Guidance's characterization of the upwind contribution captured by a 1 ppb threshold and a 1 percent threshold as "generally comparable" and agree with the Agency's observation in the NPRM that, even if this were "true in some sense," it "is hardly a compelling basis to move to a 1 ppb threshold." Third, the commenter agrees with EPA that consistency also counsels in favor of retention of the 1 percent contribution threshold.

Commenter (0323) declares that the EPA seeks to advance its proposal at Steps 1 and 2 based upon inaccurate air quality modeling and without consideration of the flexibility guidance issued by the EPA for use in the preparation of good neighbor SIPs relating to the 2015 ozone NAAQS.

Response:

The EPA has addressed these comments in Section III.B and IV.F in the preamble.

4 The EPA's Quantification of Upwind State NO_X Emissions Reduction Potential to Reduce Interstate Ozone Transport

4.1 Multi-Factor Test for Determining Significant Contribution

Comment:

Commenter (0324) claims EPA's proposal does not fully address upwind state contributions to nonattainment and maintenance areas in Wisconsin. The EPA's modeling concludes that other states contribute between 42 to 48 percent of ozone at Wisconsin's nonattainment monitors but predicted 0.1 ppb reduction in 2023 in Milwaukee and Kenosha is much lower than the additional reductions required of between 0.4 to 2.7 *p/pb* to attain in 2023. Applying EPA's contributions data to these figures indicates that the upwind state "share" of this additional reduction is 0.17 to 1.22 ppb.

Response:

The EPA's assessment of air quality benefit from the identified strategies to eliminate significant contribution is found in Section V.D of the preamble. See Preamble Sections V and VII for further discussion. A fuller summary of CAMx projections of design value change under the final rule policy are in Appendix 3A of the RIA.

Comments:

Commenter (0315). Therefore, the proposed rule arbitrarily exempts certain states where tighter controls would otherwise be triggered. The inferred criteria for such exemptions would apply equally to Wyoming. The proposed rule states, "For Wisconsin, EPA determined that the available NO_X emissions reductions from non-EGU sources ... did not provide a sufficiently meaningful and timely air quality improvement at the downwind receptors." Wisconsin was therefore exempted from the requirement to reduce non-EGU emissions. By this logic, the extremely minor contributions to receptors in Colorado would exempt Wyoming from further controls on EGU and on-EGU sources. The EPA projects 2023 maximum 8-hr ozone concentrations at Colorado receptors of 72.3 to 74.4 ppb (Table V.D-1 of proposal). Eliminating Wyoming's contribution would not alter the noncompliance at these receptors. The proposed rule also states, "ozone-precursor emissions from Oregon do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, because the total collective upwind state ozone contribution to the California monitoring sites is extremely low compared to the air quality problems typically addressed under the good neighbor provision." Therefore, the rule does not propose to require reductions from new or existing EGU or non-EGU sources in Oregon. This reasoning is offered despite the fact that Oregon's contribution to nonattainment receptors in California exceeds the screening threshold of 0.70 ppb by a factor of 3. As with Wisconsin, the standard by which EPA exempts Oregon is based on potential to influence nonattainment (Stage 3 in the proposed rule's multi-factor test). Applying the same standard to Wyoming would exempt its EGU and non-EGU sources from emissions reduction requirements.

Commenter (0758) states that Oregon is a significant contributor to numerous nonattainment and maintenance monitors in California. The EPA has not analyzed, let alone demonstrated, that Oregon lacks control measures that would help abate these significant contributions. And, therefore, the EPA's proposal to exclude Oregon from the rule is unlawful and the EPA must include Oregon in the final rule.

Commenter (0509) states Wyoming and Oregon are similarly situated and yet EPA arbitrarily treats them differently. The EPA found that Oregon was not linked to downwind California ozone receptors and was not projected to contribute above 1 percent of the NAAQS to any downwind receptors in future modeled years. However, when the EPA updated their modeling in 2021, Oregon became linked to California receptors above the 1 percent NAAQS threshold. The commenter suggests the EPA should use the same weight of the evidence approach to find that Wyoming is similarly not linked to the Chatfield receptors. In the EPA's 2016 analysis, Wyoming was not linked as an upwind state to the Chatfield receptor. However, in a similar flip-flop to Oregon, Wyoming suddenly became linked to the Chatfield receptor thanks to a new model used by the EPA in 2021. As such, Wyoming should be treated similarly to Oregon: because Wyoming was not linked to the Chatfield receptor in the 2016 modeling analysis, it should not be linked now simply because a new and unexplained model produced a different result.

Response:

The status of our evaluation of interstate transport obligations, if any, for Oregon and Wyoming in this final action is discussed in the preamble. Commenter's reference to a finding regarding "Wisconsin" in the proposal is not correct. Commenter is apparently referencing the discussion of findings made in the Revised CSAPR Update on remand from the *Wisconsin* court decision and in regards to the 2008 ozone NAAQS. 87 FR at 20055. This discussion was not in relation to an evaluation of emissions from the *state* of Wisconsin as relevant to the 2015 ozone NAAQS.

Comments:

Commenter (0547) argues that the EPA's multi-factor test at Step 3 selects controls that are not cost effective not technically feasible within the timeframe proposed. The commenter maintains that assumptions made (about cost, timing, and availability of controls, especially as to SCR control technology retrofitted to units with SNCRs already installed) to develop the uniform NO_X control stringency are incorrect and drastically underestimated. According to the commenter, after correcting the flawed assumptions, SCR retrofits do not pass the multi-factor test in Step 3, and thus, the associated emissions reductions should not be considered to be significantly contributing to downwind nonattainment or maintenance receptors. The commenter requests that the EPA revise its Step 3 analysis as follows:

- Differentiate units with SNCRs already installed from units without post-combustion controls in its multi-factor analysis, recognizing the substantial investment and emissions reductions from the already installed controls.

- Use site-specific data regarding costs and timing where available to reflect real-world challenges and realities.
- Update cost and timing estimates to reflect post-pandemic costs and labor shortages.

Commenter (0547) also "objects to the EPA's divergence from previous rulemaking precedent and the process approved in case law of identifying 'highly cost-effective' controls". The commenter emphasized that in previous rulemakings the EPA used the multi-step analysis to identify "highly cost-effective" controls that "are the easiest for upwind states to implement to reduce transport." 63 Fed. Reg. 57,356, 57,426 (October 27, 1998) (Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone). In this past rulemaking, the EPA sought to give upwind states a choice of a mix of measures to adopt to achieve the required NO_X reductions. In this proposed rule, the commenter contends that the "EPA has stripped the states of any flexibility by selecting a NO_X stringency that can only be met through a single and extremely costly emissions control device." The commenter concludes that SCR retrofits do not pass the multi-factor test in Step 3 and the associated emissions reductions should not be considered to be significantly contributing to downwind nonattainment; instead "EPA should again utilize the concept of "highly cost-effective" controls to provide states the flexibility to respond to local needs and preferences."

Commenter (0760) asserts that ozone precursor reductions from the closure or conversion to renewable fuels in over 50 large coal-fired power plants throughout the country, including in Texas, Louisiana, and Arkansas, will be substantial and should be considered in the multi-factor Step 3 analysis. The commenter notes that the EPA has proposed to significantly reduce the NO_X Ozone Season allowances for EGUs and to require many Non-EGUs in Louisiana to retrofit sources with costly NO_X control measures to reduce ozone levels by small amounts at the Houston-Aldine and Houston-Brazoria monitors. The proposed FIP reduces the Ozone Season NO_X Budget for Louisiana by 60 percent from 9,312 tons in 2023 to only 3,752 tons in 2026, an extraordinarily severe cut which will impose significant costs on regulated EGUs, if such levels are even achievable, according to the commenter. The proposed FIP would require at least 83 units in Louisiana to retrofit their sources with NO_X control technologies at a collective cost of nearly $96 million per year, but which will lead to maximum air quality benefits of no more than 0.2 ppb ozone, according to the commenter. The commenter states that "Given the extreme expense of the proposed reductions and the de minimis improvement, …at Step 3, the EPA must consider, as part of the multi-factor "significance" review, that due to coal-fired power plant retirements and retrofits, there will be significant ozone precursor reductions within both Texas and Louisiana (and elsewhere) in the years just following 2026 that may, by themselves, allow the [downwind Houston] area to reach attainment." According to the commenter, the EPA must consider the 2026 retirements in its analysis, even if the corresponding emissions reductions will not be realized until 2027-2029. The commenter concludes that "even if all of the EPA's projections were accurate (which is denied), this de minimis improvement would not be worth the cost to Louisiana, particularly in light of the imminent reductions from coal-fired power retirements."

Response:

The EPA addresses many aspects of this comment in the EGU Mitigation Strategies Final Rule TSD and in preamble Section V.B-D. The EPA notes its costs are representative and any individual unit cost that varies from that representative value does not disqualify the representative nature of that cost. It certainly does not automatically justify removing those reductions from inclusion in the multi-factor test. Moreover, use of an average is not only reasonable, but well aligned with the EPA's use of a trading program for implementation which allows compliance pathways such as allowance purchase. We address the role of our cost analysis as relevant to non-EGUs in Section V.B, C, and D of the preamble and in Chapter 2.2 of this document. We note that while CSAPR and prior transport rules used the term "highly cost-effective" to describe generally the nature of the control requirements being finalized, those selected mitigation levels were also influenced by a variety of factors in EPA's multi-factor test and did not constitute an upper bound on what is sufficiently cost effective for the purposes of eliminating significant contribution to nonattainment or interference with maintenance of any given NAAQS. For instance, the CSAPR Update rule was a partial remedy for which only mitigation measures available within one year were available (e.g., SCR retrofit was omitted from inclusion not because of cost, but because of timing). Similarly, the Revised CSAPR Update Rule was addressing an air quality problem that was projected to be resolved by the time that SCR retrofits could be in place, so they were again omitted due to variables other than cost. The stringency determined through the application of Step 3 for the 2015 ozone NAAQS full remedy of this action includes additional measures in recognition of the air quality problem and projected duration of those exceedances, and those measures have been demonstrated to be cost-effective.

The TSD and preamble and Section 10 of this document discuss comments regarding supply chain challenges in 2022, the likelihood of them persisting into the future, as well as sensitivity analysis that still supports the reasonableness of the EPA's selected stringency level under higher technology cost assumptions.

In regard to future retirements, those are incorporated into the EPA's Step 1 and Step 2 analysis in a manner that includes both known and projected retirements. The EPA's 2026 EGU projection used to identify linked upwind states identifies a substantial amount of projected retirement occurring in the baseline, which is reflected in our air quality and contribution projections.

In regard to comments on looking at years beyond 2026, the EPA clearly explains in the preamble Section I and IV why it is necessary to choose analytic years of 2023 and 2026 given their relationship to the NAAQS attainment dates and prior judicial direction. In preamble Section VI.B, the EPA explains changes in the final rule that will facilitate EGU compliance in 2026 and later years.

Finally, the EPA has determined that not only are the EGU reductions identified in Louisiana reasonable from a cost perspective and viable from a timing and Final Rule program framework, they also are attributable to a small portion of generation from the state. The EPA finds that the bulk of reduction potential identified in Louisiana EGUs come from just a handful of large emitting sources currently lacking post-combustion controls. While commenters frame these reductions as a 60 percent reduction from fleet emissions, the EPA notes that these reductions are occuring at units representing approximately 6 TWh of the State's 45 TWh (*i.e.*, 13 percent) of the state's 2021 ozone season generation (See EIA Form 923 and Appendix A of the Ozone Transport Policy Analysis TSD). The suggestion that the reduction is a burdensome ask on the state's entire EGU Fleet misconstrues the relatively narrow fleet segment of large emitters identified as having mitigation measures. The EPA's Step 3 analysis, and ensuing Step 4 state emissions budgets, assume that the vast majority of units within the state only need to continue to operate in a manner consistent with their recent 2021 operation.

Comments:

Commenter (0436) notes, while the EPA provided extensive cost benefit analysis for the emissions reductions required by this FIP as expressed in the usual units of dollars per ton, the EPA made no effort to quantify the cost of controls in terms of ozone reductions at the downwind receptor, *i.e.*, dollars per ppb ozone reduced. The commenter believes that this is an important metric to examine and make public as it can help shed light on if the prescribed controls are reasonable relative to their downwind impact. The commenter requests that this metric be included with the results of any additional modeling performed as part of this rule making.

Response:

The commenter's request to include an additional metric to determine if the prescribed emissions controls are reasonable is not necessary to define significant contribution and is contrary to the Agency's historical approach at Step 3, which it is continuing in this action. In Section V of the preamble, we present our Step 3 analysis explaining how we identified significant contribution. This approach of analyzing different levels of uniform control stringency across all linked upwind states under a multifactor analysis that includes consideration of cost-effectiveness is essentially the same analysis the EPA applied in its CSAPR rulemakings to define significant contribution and which the Supreme Court upheld in *EME Homer City*, 572 U.S. 489. Commenter does not further explain how a "dollars/ppb" metric could be reliably constructed, or applied in the context of the complex interlinkages that characterize ozone transport at the regional scale.

4.2 Control Stringency Levels and Mitigation Strategies

Comments:

Commenter (0341) contends that the FIP does not result in "substantial and meaningful improvements in air quality." According to the commenter, the EPA's own analysis the proposed rule, if finalized, would result in a cost of $22 billion at a three percent discount rate. However, the commenter provides that the EPA's analysis (87 Fed. Reg. 20097) shows the following air quality improvement from the four categories of controls involved:

- Existing EGU controls in 2023 0.07 ppb
- New EGU controls/Gen. shifting in 2026 0.36 ppb

- Non-EGU (Tier 1) 0.18 ppb
- Non-EGU (Tier 2) 0.04 ppb
- Total 0.64 ppb

As such, the commenter states that the projected air quality improvements fall short of the threshold for "meaningful" improvements that would contribute toward compliance with the 70-ppb ozone NAAQS. The commenter provides that in the six previous ozone transport rules the EPA has finalized in the last ten years, the EPA has exhausted "meaningful" transport improvements from EGU NO_X reductions.

As such, the commenter concludes that in developing the rule, the EPA focused exclusively on interstate transport and failed to address local emissions from the nonattainment monitor areas that are larger contributors to nonattainment. Further, the commenter states that the EPA proposes to continue penalizing point sources like the power sector while failing to address mobile source (transportation sector) contributions despite the fact that it has been established that mobile sources are the primary contribution to the remaining air quality problems.

Commenter (0314) writes that the proposed rule will increase electricity costs by requiring expensive emissions controls at coal- and natural gas-fired power plants.

Additionally, the commenter (0499) states that the EPA has not provided nearly enough time to implement the recommended control measures in Louisiana (or other similarly-affected states) assuming such equipment is even available from vendors considering the current global and domestic economic and supply chain issues. More likely, the commenter expects the exorbitant costs to Louisiana utilities will result in the unnecessary early retirement of certain EGUs, price increases to consumers and potential electric reliability issues for certain regions and during certain seasons of the year. For this reason, the commenter requests that the EPA take the necessary time to properly evaluate air quality impacts in accordance with its own air modeling guidelines and re-evaluate its proposed control structure for regulated utilities.

Response:

In Section V of the preamble, the EPA describes the EGU and non-EGU sectors and sources that are included in the rule. The EPA's multifactor analysis is rooted in identifying technologies, that when applied to sources in a sector, result in cost-effective emissions reductions that have important air quality impacts. Section V.A of the preamble describes the EPA's response about mobile source emissions within Step 3 of the Transport framework. The EPA describes the Step 4 implementation process for EGUs and non-EGUs in Section VI of the preamble.

The EPA appropriately characterized the emissions reductions and then properly assessed the air quality effects of these emissions reductions. In preamble Section V.D, the EPA examined overcontrol for each state for each receptor.

Section IV.E of the preamble describes EPA's air quality modeling projecting nonattainment and maintenance receptors. The EPA disagrees that the effects of this rule are "vanishingly small" or that the improvements constitute overcontrol. The EPA's overcontrol assessment is described in preamble Section V.D, the Ozone Transport Policy Analysis Final Rule TSD Section C.3 and Section 10.2 (States Not Linked in 2026) and includes an evaluation of emissions reductions from EGUs and non-EGUs. As described in the RIA the benefits are significant and exceed the anticipated cost.

As described in Section I of the preamble, based on the multi-factor test applied to both EGU and non-EGU sources and our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 23 upwind states subject to EGU and non-EGU emissions reduction requirements under the rule. For additional details about the multi-factor test and the over-control analysis, see the document titled Ozone Transport Policy Analysis Final Rule TSD included in the docket for this rulemaking. For more information about the costs of the rule, see Section I.C of the preamble as well as the RIA.

See preamble Section V.B and the EGU NOx Mitigation Strategies Final Rule TSD for the EPA's discussion and response about timing and purported supply chain issues.

Comments:

Commenter (0214) urges the EPA to expand the covered sources further by including all power plants and all major industry sources in both upwind and downwind areas. The commenter also recommends that if polluting sources have existing controls, they should be required to run them by the start of the next ozone season: May 1, 2023. If polluting sources do not have existing controls, they should be required to install and optimally run them by May 1, 2024. The commenter also states the rule should not excuse state or polluter obligations under existing programs like the Regional Haze Rule that specifically aim to achieve year-round clear skies in national parks and wilderness areas. Many states covered under this new rule, including Utah and Wyoming, continue to host egregious emitters harming national park skies and over a dozen power plant units are already long overdue in complying with haze obligations. As the EPA moves forward with this regulation, it should not delay or sacrifice these necessary emissions reductions.

Commenters (0257, 0503) support the proposed rule's straightening and expansion of interstate transport ozone obligations.

Commenter (0314) states California is listed as generating the highest contributions at 34.24ppb. On the other end of the spectrum – Wyoming at 0.81ppb. The EPA has determined the emissions controls needed to ensure the state with the largest emissions contributions are reduced to the point of bringing the downwind state into attainment. Wyoming facilities should not be burdened with the cost and consequences of installing the most expensive emissions controls because Wyoming facilities are not contributing nearly as much as other states.

Commenters (0332, 0372) state electric companies are building the infrastructure needed to support increased electrification of other sectors and supporting electrification to leverage the reductions from the power sector to reduce emissions from other source categories is a tremendous opportunity the EPA should fully explore. The commenters also state the EPA is correct to propose requirements for several industrial sectors and should include them in any final rule and has more than ample record evidence to support finalizing these requirements. The Agency is correct to assess the potential for cost-effective NO_X and VOC emissions reductions from all significant contributors to interstate transport related to ozone, and to then move forward with requiring reductions from those sectors. It is certain that cost-effective NO_X reductions opportunities exist for stationary sources outside of the power sector that combined make up three-quarters of the national total for stationary source NO_X emissions. Commenter (0372) also states the EPA acknowledges mobile source contributions but declines to explore reductions. The Rule provides no explanation for why the EPA passes on mobile source emissions reductions in upwind states.

Commenter (0374) states based on reductions already underway as a result of state-level regulatory development and voluntary action, the inclusion of NO_Xlimitations in a FIP is not necessary to continue to reduce NO_Xemissions and ozone precursor transport from the specified 26 states. Of the 26 states referenced in the rule, many of the existing MWCs are currently subject to RACT-based NO_Xemissions limits that are well below the current federal NO_Xemissions limits (40 CFR 60, subpart Cb/Eb). If the EPA decides to move forward with inclusion of MWC NO_Xstandards in a FIP, the Agency should give states the flexibility to set standards that are appropriate for the MWCs located within their jurisdictions, in recognition of technological differences. In a June 2021 report, OTC initially recommended a NO_X emissions limit of 105 ppmvd seven percentO2 on a 30-day averaging basis and 110 ppmvd seven percent O2 on a 24-hr averaging basis.

Response:

The EPA acknowledges that MWCs included in this rulemaking may be subject to other regulatory programs, however the Agency disagrees that this should exclude those facilities from this rulemaking. The EPA notes that most non-EGUs have their own unique regulatory and permitting history in relation to other requirements under the CAA. 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 described in Section VI.B.2 of the preamble for the proposed rule, 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. Using the criteria developed in the Screening Assessment at proposal, the EPA has evaluated MWCs and determines that MWCs should be included in this final 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.

In preamble Section III.B, V, and VI.B, EPA describes the approach for the final rule applying the 4-step transport framework to eliminate significant contribution and interference with maintenance.

The EPA’s response to comments regarding inclusion of mobile sources can be found in Section V.A of the preamble

As explained in preamble Section VI.B.9, the EPA adjusted – based on comment – its allocation methodology in this final rule to assume units that have not installed or operated their SCR in the past, have a historical maximum emissions assumption in the allocation methodology adjusted to match the stringency assumptions used in the state budget process. This further ensures that two equal sources different only in their operation of existing controls will not experience a scenario where the source not operating its control receives more allocations.

Comments:

Commenter (0379) urges the EPA to extend NO_X emissions control requirements to all combustion-driven electricity generating units (EGUs) and all major industry sources in both upwind and downwind areas to reduce both transported and localized NO_X and ozone pollution. Doing so is essential in meeting the EPA's Objective 4.1 to Improve Air Quality and Reduce Localized Pollution and Health Impacts in its Strategic Plan. Potential revision of the current 70 ppb, which the Lung Association has repeatedly asked to be lowered to no higher than 60 ppb as warranted by science, could bump up new areas into nonattainment or into different classification of nonattainment. The EPA should seize this opportunity to make the controls as stringent as technologically feasible to maximize the public health benefits, especially given the time-intensive steps from promulgation to implementation.

Commenter (0398) states the proposed FIP imposes uniform controls over a wide range of manufacturing technologies within specific NAICS codes, despite the fact that many types of equipment and manufacturing processes may exist within the same NAICS code. The commenter also notes the infeasibility of SCR installation and incorrect reduction estimates for certain sources.

Response:

Comments on the Non-EGU Screening Assessment are addressed in Chapter 2.2. We note the purpose of the rule is not to impose emissions controls as stringent as technologically feasible but to define and eliminate significant contribution for the 2015 ozone NAAQS.

Comments:

The commenter supports the EPA providing flexibility for companies that have entered or may enter into enforceable agreements with the EPA to retire fossil units by a certain date. Timing of this flexibility should be informed by applicable attainment dates as well as an understanding of how those units may operate prior to the retirement date. For such units, the EPA should consider flexibility in state budgets as well as the daily backstop rate. Individual member companies may submit comments at this docket with more specific recommendations on the EPA's use of flexibility.

Commenter (0758) strongly support the EPA's proposal to adopt several safeguards to ensure that all power plants participating in the trading program actually control their pollution. The commenter also strongly supports the EPA's proposal to require reductions in NO_X emissions from other high-polluting industrial sources. The EPA is also correct to propose to secure these reductions through rate-based limits, rather than an emissions credit trading regime.

Commenter (0758) also states the EPA's proposed rule under controls ozone pollution, and greater reductions are therefore necessary. The commenter notes the emissions reductions that the EPA proposes to require in 2023 are very small, amounting to less than one percent of total ozone season NO_X emissions for 22 out of 26 upwind states. Even in 2026, when all emissions reductions are projected to be implemented, ozone-season NO_X emissions will be reduced by less than 10 percent in all but five covered states. The states with the highest NO_X emissions, Texas and California, will reduce their emissions by only 4 and 1 percent, respectively. The impact on downwind ozone levels is projected to be correspondingly modest in comparison to the scale of the problem. In 2023 the estimated ozone reduction is projected to be less than 0.1 ppb at most receptors. Even at the receptors that see the greatest benefit, in Connecticut, Illinois, Texas, and Utah, ozone levels are projected to be reduced by less than 0.2 ppb. Id. Even in 2026, after all proposed reductions have taken effect, the impact at most of the relevant downwind receptors is less than 0.3 ppb. While these modest, incremental ozone reductions will deliver substantial benefits to public health and the environment, harm from excessive ozone pollution will persist if the EPA fails to strengthen the proposal. The commenter notes the EPA should be consistent with CAA and Supreme Court's decision in EME Homer to not under control pollutions and requiring the additional reductions in interstate pollution needed for attainment and maintenance of the ozone standard is not "impossible." The commenter also notes the EPA has failed to sufficiently explain and substantiate its impossibility claims. Far from demonstrating with evidence that achievement of additional pollution reductions is impossible in the timeframes contemplated by the Act, and explaining those conclusions with particularity, the proposal declares that "all possible emissions reductions" have been required, "in all cases." In addition, any non-compliance with the EPA's legal obligations must be limited to the non-compliance that is strictly necessary. To allow otherwise would impermissibly "seize on a remedy made available for extreme illness and promote it into the daily bread of convenience."

Commenter (0758) also states the EPA must make clear that this rule's seasonal ozone reduction measures do not, and cannot, supplant the states' obligation to make reasonable progress toward natural visibility in all class I areas. This rule does not, and cannot, exempt states or the EPA from their obligations to implement haze plans that ensure "reasonable progress" under 42 U.S.C. 7491(b)(2). First, unlike the statutory and regulatory process for exempting sources from any BART analysis, neither the CAA nor the Regional Haze Rule allows states or the EPA to exempt sources from the reasonable progress requirements of the statute. Neither the CAA nor the Regional Haze Rule, however, provides any such mechanism for exempting states from the requirement to issue comprehensive haze plans that include enforceable emissions limitations to ensure "reasonable progress," after evaluation of the four statutory factors. Finally, by making clear that this rule does not supplant the states' obligations under the Regional Haze Rule, the EPA can avoid even further delay in the implementation of Congress's visibility mandate.

Commenter (0428) acknowledges the significant effort undertaken by the EPA in the FIP analysis, which involves the EPA's interpretation of dated emissions estimates supplied by and/or vetted with some states in the commenter's region; however, questions if the EPA's approach would be able to change air quality as it predicts.

Response:

See the EPA's description of the final rule approach in preamble Section III.B. The full elimination of significant contribution and interference for all states with regards to overcontrol is described in preamble Section V. *See also* Section 2.2.9 of this document.

The EPA's assessment of overcontrol for all receptors can be found in preamble Section V.D and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD.

The EPA fully documented its Step 3 and overcontrol assessments at proposal (see, e.g., the Ozone Transport Policy Analysis Proposed Rule TSD). The EPA updated its emissions inventories, updated its air quality modeling, and updated its assessment of emissions reductions availability for both EGUs and non-EGUs for the final rule. *See* Section V of the preamble. The presentation of other forms of cost and benefit, including air quality benefits, associated with this action, can be found in preamble Sections I.C and VIII as well as the RIA.

Comments:

Commenter (0329) encourages the EPA to continue to pursue non-point source reductions in ozone precursors. As facility nitrogen oxide emissions go down over time, it is important to achieve NO_X and VOC emissions reductions from transportation and neighborhood sources. These actions would protect local air quality and health as well as improve national issues like ground-level ozone.

Commenter (0398) understands the complexity of modeling for downwind impacts, and the importance of controlling the correct set of sources so that downwind impacts are minimized. However, this determination requires more robust source-apportionment analysis, and the process can add a month or more to assess just a single state. The EPA was certainly not afforded the time necessary to perform a sufficiently robust determination through modeling because of the consent decree timeline. This is why the Agency performed base modeling and used scaling at a statewide level to determine the "effect" of their proposed control strategy on upwind monitors. However, a restrictive deadline is no excuse for performing conventionally inept technical analysis (e.g., without QA/QC data, riddled with unchecked assumptions, etc.) to support such an economically aggressive proposal. Because of the immense scope of the proposed FIP, this is precisely the time the EPA should have doubled-down on supporting analysis and documentation to be sure the proposal that was produced is defensible through sound science and by reliable reasoning. In its present form, the proposed FIP offers neither of these, and the proposed controls in the FIP are therefore indefensible and unreasonable. To properly correct these deficiencies, the EPA must perform new modeling that takes into account state corrections and the EPA should perform a more robust source-apportionment analysis.

Commenter (0505) notes an essential assumption in the EPA's estimation of downwind air quality improvements is that the location of emissions changes within an upwind state were considered equal. The EPA did not provide a rationale for why this assumption was appropriate for states with a large geographical area such as Texas, which could lead to an inaccurate estimate of impacts to downwind sources. Such an inaccurate estimate could be determinative of whether a state should be included in the proposed FIP—the EPA's failure to justify this central assumption is in error. The commenter believes the EPA should correct this error, explain its rationale, and verify the accuracy of its estimates.

Commenter (0315) states the proposed rule aggregates all the large point sources in Wyoming into a single area source. This ignores the source location and prevailing wind patterns at that location. An EPA TSD admits that "downwind air quality improvement is assumed to be indifferent to the source sector or the location of the particular emissions source within the state where the ton was reduced."

Commenter (0798) adds the EPA's modeling does not accurately reflect the control efficiencies the EPA assumes (and requires) in the proposed rule. For instance, it appears that the EPA performed a modeling run where the EPA assumed emissions reduction of 30 percent across all covered sources to demonstrate attainment status at nonattainment and maintenance receptors, and a model run based on the statewide emissions reductions the EPA expected based on the non-EGU screening assessment. But neither of these modeling runs reflect the emissions standards that the EPA actually proposes. As previously noted, the modeling run based on the non-EGU screening assessment significantly undercounted emissions reductions associated with the proposed rule limits. And the modeling run assuming across the board reductions of 30 percent likewise does not match the limits in the proposed rule, which assume unit specific limits far more stringent than 30 percent in many cases. For EAFs, for instance, the "EPA based the emissions limit of 0.15 lb/ton of steel on projected reduction efficiency of 40-50 percent as compared to existing permit limits for EAFs". The EPA cannot haphazardly model one set of assumptions and then propose something totally different. The EPA should conduct modeling that actually reflects the rule being proposed.

Response:

In preamble Section III.B, V, and VI.B, the EPA describes the approach for the final rule applying the 4-step transport framework to eliminate significant contribution and interference with maintenance.

The EPA updated its emissions inventories, updated its air quality modeling, and updated its assessment of emissions reductions availability. As described in preamble Section IV and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, the EPA used photochemical modeling to determine the set of receptors and air quality contributions for Steps 1 and 2 of the transport framework. The EPA's analysis of Step 3, including the air quality components of the multifactor test is robust (see Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, the AQAT RTC in Section 10.2, and Section 4.6 (Consideration of Volatile Organic Compound (VOC) Emissions or Other Pollutants) for additional details). As described in preamble Section V.D and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for the EPA's overcontrol analysis, where the EPA demonstrates that the rule (using all the updated data) does not overcontrol any states that are included in the rule.

In addition, the EPA performed photochemical modeling using CAMx of a Final Rule Policy Control scenario. The results of which confirm the Step 3 assessment made using AQAT (see, e.g., Appendix J of the Ozone Transport Policy Analysis Final Rule TSD for some details).

For response to comments 0505, 0315, and 0798: We note that the calibration factors used with AQAT already account for the distribution of emissions reductions across a given state. So, while it is correct that in looking at the effects of the policy as a whole at the state level, we ascribe a single value regardless of where reductions are located, that value appropriately averages the effects of emissions reductions in a way that accounts for distribution. We further note that we only used the 30 percent-reduction scenario as a means of deriving calibration factors, not as an estimate of the effects of the rule. See Section 10.3 (Comments about AQAT) and the Ozone Transport Policy Analysis Final Rule TSD Section C.5 and C.4 for further discussion of issues related to AQAT.

4.2.1 EGUs

4.2.1.1 Support for Proposed or Stricter EGU Controls

Comments:

Commenter (0259) agrees with the proposed rule that in the near-term, fossil fuel-fired EGUs can and should do more to curb emissions, based on existing NO_X controls and operating changes. The commenter noted that not running already-installed pollution controls to save money should not be an option, given the well-understood harms, and that poorly controlled units should install controls immediately or stop operating. The commenter supports maximum daily emissions rates for NO_X from large coal-fired plants being in-force at the same time controls would be required for plants lacking controls.

Commenter (0286) states its commitment to meeting strict emissions limits at the source using already-installed SCR and wet flue-gas desulfurization systems, rather than paying to pollute through the purchase of emissions allowances.

Commenter (0352) supports the EPA's proposed reductions for EGUs without controls or that are under-controlled.

Commenter (0367) states the 0.08 lb/MMBtu is higher than the typical rate achieved by sources running their controls: over half of power plants during their third-best season of operation achieved a 0.068 rate or lower. In 2021, 71 percent of SCR-equipped power plant sources in certain states covered by the proposal achieved better than the 0.08 rate the EPA proposes. The commenter asserts that the "EPA has repeatedly underestimated the emissions reductions available from SCRs and should not do so again. Establishing a benchmark rate that is too lenient permits upwind states to continue emitting far too much ozone precursor pollution." The commenter also states that despite the substantial emissions reductions in the Proposal, the EPA should strengthen the Proposal to eliminate significant contribution as expeditiously as practicable. The EPA should de-couple the SCR and SNCR timelines and set emissions budgets to require SNCR sooner to comply with the statutory mandate to eliminate significant contribution as expeditiously as practicable.

Regarding the ozone season emissions rate limit, Commenter (0433) contends that the proposed FIP mass cap allows the unit operators to decide if they want to optimize the SCR or not, simply by operating less (meaning a lower amount of heat input or burning less coal) during an ozone season, albeit now subject to the proposed backstop daily emissions rate of 0.14 lb/mmBtu. As an assurance that units capable of operating at lower NO_X emissions rates do not choose to run less optimally over extended periods in the space created below the backstop daily rate, a reasonable and further constraint can be established using the EPA-defined reasonable rate of 0.08 lb/mmBtu for the entire ozone season.

Likewise, Commenter (0503) states that the seasonal mass cap may be too lenient to drive timely attainment of the standard. The commenter suggests the EPA either (1) lower the mass cap, or (2) establish an overall ozone season NO_X rate cap along with the mass cap. The commenter requests that the EPA apply a lower fleet-wide optimized NO_X rate between 0.06 and 0.07lbs/mmBtu.

Commenter (0758) supports the EPA's decision to include a unit-specific secondary emissions limitation contingent on assurance level exceedances within a state. The commenter also recommends strengthening the unit-specific secondary emissions limitations further by removing the benchmark floor and using each unit's historical performance to set its benchmark. Overall, the commenter supports the unit-specific secondary emissions limitation as a way to help states stay within their assurance levels as required by the CAA. However, the commenter further states that, given the CAA's requirement to eliminate significant contributions to downwind nonattainment and maintenance issues, if the EPA for whatever reason ultimately did not implement the unit-specific secondary emissions limitation, this commenter strongly recommends that the EPA include a fallback provision in the final rule that would automatically increase the allowance-surrender ratio for emissions that contributed to an exceedance of an assurance level above the 3-to-1 ratio in the current rule to a level high enough to prevent owners and operators from simply turning off controls and buying excess allowances from their counterparts in other states. As history has demonstrated, the 3-to-1 ratio is not enough to deter owners and operators from this type of gamesmanship and needs to be strengthened going forward if a unit-specific secondary emissions limitation is not implemented, according to the commenter.

Response:

See preamble Section V.B and the EGU NO_X Mitigation Strategies Final Rule TSD for more discussion on the derivation of the 0.08 lb/mmBtu rate. Although a unit-by-unit rate determination as suggested by commenter, as opposed to a uniform 0.08 lb/mmBtu rate, may result in some units being assigned greater reduction potential (*e.g.*, a lower rate) and some units being assigned a lower reduction potential (*e.g.*, a higher rate), the EPA's use of the nationwide 3rd best year average from its historical data set is appropriate for deriving state emissions budgets under a trading program. It sets a widely obtainable rate consistent with optimization, and still encourages better performance from units who are capable of overperformance through its use of a trading program. The EPA also notes that units performing better than 0.08 lb/mmBtu in 2021 are assumed to continue to do so in determining the future year budgets. The 0.08 lb/mmBtu application is only relevant to those SCR controlled units that were not achieving at least that level in 2021 – meaning in effect the fleet-wide average imposed in the Engineering Analysis and State Emission budgets is less than 0.08 lb/mmBtu, consistent with the notion that 0.08 lb/mmBtu is imposed only for the non-optimized portion of the fleet with the remainder continuing to operate their less than 0.08

lb/mmBtu recent historical rates.

4.2.1.2 Issues with Generation Shifting

Comments:

Commenter (0282) states that the EPA's modeling calculated approximately 88 tons of NO_X reduction potential in New York State, based on generation shifting, but the commenter questions the level of NO_X reductions that are possible from generation shifting in the downstate area of New York. Relying on generation shifting, which would increase activity at EGUs located outside of the downstate area, ignores transmission constraints and could lead to a system reliability risk. The commenter cautions the EPA that this level of emissions reductions from generation shifting is unlikely and will not be achievable to contribute to ozone attainment in New York.

Commenter (0319) states the EPA projects that there will be 318 GWh of generation shifting in Indiana under the proposed rule. The commenter is concerned that these generation shifting assumptions by the EPA simply cannot be implemented, because the Indiana Utility Regulatory Commission ratemaking and approval process may not allow it. Likewise, Commenter (0302) notes that the EPA did not consider that in the state of Missouri, there are two RTOs as well as an Independent Transmission Operator. Shifting generation between the Transmission operators is not feasible as they both manage separate grids and load profiles. Similarly, Commenter (0408) asserts that the EPA's assumption that generation shifting can occur to any generating unit within a state does not correlate to the unit allocations within a state, nor take into consideration the market availability and transmission constraints of purchased power. The commenter notes that the generating entity must first serve their own load before providing energy on the open market. Commenter (0408) urges the EPA to remove generation shifting from the regulation, or at least limit it to an IPM region within a state.

Commenter (0340) states the EPA's assumption regarding generation shifting is flawed and the ability to replace potential generation lost simply cannot meet the EPA's proposed timeline. The commenter explained that allocations to existing units have been reduced for future years based on the EPA's flawed assumptions for generation shifting, and further asserted that to overcome the capacity shortage, Kentucky EGUs would have to construct new units, which cannot be accomplished in the EPA's proposed timeline. Commenter (0340) concluded that the EPA has not given adequate consideration to the implication of generation shifting and the regulatory requirements necessary to allow those units to operate in that capacity.

Commenter (0344) states it is unclear whether the EPA's projected generation shifting in Indiana will actually occur, because unit operators have no control over how electricity is dispatched. Regional transmission organizations (RTOs) dispatch based on cost-effectiveness and reliability. To further complicate matters, the state of Indiana falls under two different RTOs. The commenter asserts that the complexity of the Indiana electric grid management along with the lack of control that unit operators have regarding electricity dispatch mean that the EPA's generation shifting cannot be relied upon as a means to reduce NO_X.

Commenter (0372) states the EPA's generation shifting model fails to factor in market constructs and NERC reliability standards altogether. The EPA's model creates a fiction between MISO and PJM, identifying a net Kentucky generation loss in the PJM system with the greatest net gain in MISO. The commenter further suggests that, if generation shifting must prevail, then generation shifting should be in the direction of the most-controlled generating assets, without a preference against coal (noting that the EKPC has one of the most controlled and lowest NO_X emitting fleets in the U.S., with an emissions rate between 0.06-0.076 lbs/mmBtu).

Commenter (0385) supports the EPA's "cap and trade" approach and contends that the proposed reduction of allowances in the program will essentially end the use of trading as a compliance alternative and either force technology installation or generation shifting. While generation shifting may be available to utilities with large and diverse fleets, EGUs with single-unit ownership can only reduce unit runtime commensurate with NO_X allocations and seek to buy power to make-up the shortfall. Single site cooperatives do not have a portfolio of assets that they can throttle up and down during the ozone season, according to the commenter.

Commenter (0395), in addition to generation shifting legal authority issues, also states the allocation formula introduced by the EPA in the proposal will continually shift allocations away from older units and away from coal- fired generation. Even those existing coal plants which are currently operating with SCR will experience a reduction in their allowances under this Proposal.

Commenters (0404, 0431, 0540, 0536) object to generation shifting from a financial perspective. The commenters also note the assumption that the existence of low-NO_X -emissions EGUs are available to operate in place of higher-NO_X -emissions EGUs is not true in all fleets. Commenters (0536, 0540) explain that when generation is shifted away from an EGU that provides power to a municipal utility or corporation, the community served by the utility or corporation is exposed to the volatility of market energy and capacity pricing. Further, the strategy of generation shifting would necessarily cause uneconomic EGUs to be dispatched, thereby increasing market energy costs for the utility or corporation.

Commenters (0409, 0431) assert that generation shifting is fatally flawed and should be eliminated as a NO_X reduction "technology" because it reduces state budgets, which forces down unit-level allocations to significant levels that do not recognize the reality of utility markets. The commenter notes that the EPA has many reliable and technologically proven choices available to reduce transport emissions (*e.g.*, the EPA should have explored mobile source emissions reductions through inspection and maintenance programs) and asserts that it is arbitrary and capricious to rely instead on a flawed generation shifting model as the means to achieve the EPA's goals. The commenter concludes that the EPA eliminate the generation shifting step in the state budget setting process and instead adopt the optimized baseline values as the final state budget numbers and recalculate the remaining state budgets accordingly.

Commenter (0409) states, in addition to cost/benefit and legal authority issues, generation shifting is not a "technology" that is available to smaller systems. The commenter also states the Generation Shifting Base Case is in error – causing the entire model to produce flawed results. And the Generation Shifting Model assumes the free flow of electricity across states and regional reliability organizations and all transmission constrained areas which ignores market rules and transmission infrastructure limitations. The commenter also notes there are discrepancies between the Proposed Appendix A Proposed Rule State Budget Calculations and Engineering Analytics Spreadsheet and Appendix D-1 of the Ozone Transport Policy Analysis Proposed Rule TSD. The commenter states the Model's generation shifting outcome causes unintentional, nonsensical results and the scarcity of allowances coupled with allowance bank restrictions will result in very costly allowances for purchase.

Commenter (0411) notes the EPA constrained its generation shifting analysis as a mitigation strategy with an in-state only approach. In the EGU NO_X Mitigation Strategies Proposed Rule TSD, it is unclear if the EPA considered that the Panhandle of Texas is not part of ERCOT but the SPP.

Commenter (0505) notes that the EPA has mistakenly stated that it is reasonable to quantify and include emissions reduction potential from generation shifting, without regard for any potential impacts to electric reliability or pricing.

Commenter (0553) asserts that the EPA's inclusion of generation shifting based on IPM modeling analysis is inappropriate, significantly flawed, and does not support use of the analysis for setting regulatory policy or NO_X budgets. Commenter (0553) supports the Midwest Ozone Group's extensive comments on the subject of generation shifting. Likewise, Commenter (0323) provides criticism of the three IPM runs that establish generation shifting results, especially the base case run, claiming it does not represent the generating unit profile in many of the 25 states that comprise the proposed FIP region. Commenter (0323) also asserts that the most notable concern is the EPA's erroneous assumption of unrestricted transfer of generation across a state, particularly so for states with multiple Regional Transport Organizations ("RTOs"). The EPA and IPM do not consider transmission constraints and the associated reliability issues that can occur during the height of the ozone season, according to the commenter.

Commenter (0554) supports generation shifting as a market-based strategy to cost-effectively reduce emissions, but the EPA should not mandate generation shifting, instead allowing generation shifting to occur via the market to minimize costs. The commenter also asks the EPA to reconsider aspects of its proposed rule that would inhibit generation shifting as a means of compliance and questions the accuracy of the IPM results underlying the EPA's generation shifting assumptions. Commenter (0554) opposes the EPA's attempt to force generation shifting through assumptions based on its IPM, and instead asks the EPA to allow market forces to provide for generation shifting when most efficient and cost effective for reducing emissions.

Commenters (0306, 0342) outright proclaim that the EPA inappropriately and without authority requires the consideration of electric generation shifting as a control mechanism in addition to requiring new or optimized NOx controls and stress the point that these provisions put even more strain on an already strained electric grid.

Commenter (0348) is unclear of the possible effects that may result from EPA's generation shifting assumptions and worries that the proposed FIP might alter how their members and generation owners offer their resources into markets (including run time limitations), which may further limit the commenter's (MISO's) options when committing and dispatching resources.

Response:

See Section V.B1.f of the preamble for discussion on the EPA's treatment of generation shifting at Step 3 in this final rule. *See also* Chapter 1.3.4 in this document. Generation shifting is one of multiple compliance strategies EGUs will be able to consider as a means of complying with the Group 3 trading program requirements.

The comments above, the majority of which target IPM estimated emissions reductions for generation shifting as a mitigation strategy at Step 3, are mooted by the EPA's exclusion of any such estimates in the state emissions budgets in the final rule. However, the EPA notes that IPM projected levels of generation shifting are an established practice used by the EPA successfully in prior power sector rules to inform both stringency levels and cost estimates, and the EPA's power sector modeling is informed by a comprehensive representation of generation/transmission-related constraints (e.g., wheeling charges, NERC aligned grid regions, NERC generating and availability data for utilization limits and many others described and discussed in the IPM documentation and the Resource Adequacy TSD).

In regard to comment that it is unclear if the EPA considered that the Panhandle of Texas is not part of ERCOT but the SPP, the EPA's IPM modeling does subdivide Texas into separate corresponding NERC sub regions (including capturing those SPP sources in the panhandle). See the NEEDS file and chapter 3 of the IPM documentation. The particular context of the comment is moot, as the broader state-level generation limitations (to which the commenter is speaking) that were also included in the proposed Step 3 generation shifting analysis are not part of the EPA's Step 3 analysis at final rule.

4.2.1.3 Issues with Proposed Control Technology

Comments:

Commenter (0282) notes that the EPA identified four dual-fueled units in New York State as candidates for SCR retrofit using Appendix A – Proposed Rule State Emissions Budget Calculations and Engineering Analytics. This may be difficult to achieve, according to the commenter, because: 1) if modeling did not accurately represent natural gas as the primary fuel, the weighted emissions rates would be overestimated and will affect the threshold $15,600/ton decision point to add SCR; 2) some facilities lack physical space onsite to accommodate addition of an SCR; 3) the age of the unit may prohibit additional capital investments; and 4) New York State policy requiring compliance with the Climate Leadership and Community Protection Act may lead to near-term replacement of those resources.

Commenter (0324) states the EPA should not apply additional NO_X control stringency to Wisconsin EGUs that are already well controlled. Units that already meet the EPA's target for optimized SCR control with existing alternate control systems should not be required to install new SCR retrofit controls when the gains would be minimal.

Commenter (0336) states the EPA assumed that in the near term the owners will devote resources to maintaining, enabling, and using the existing SNCR controls then subsequently installing SCR. A more likely scenario is that the owners would buy allowances to cover the additional emissions until a decision is made regarding SCR installation since buying allowances provides a short-term solution and would not interrupt facility operations as would overhauling an SNCR system that is not operational. The EPA should adjust their state budget calculations to reflect this more likely scenario.

Commenter (0366) developed a rough estimate of installing SCR on Arthur Kill 20 without considering site-specific factors and technical feasibility. This estimate is over 30 percent higher than EPA's capital cost estimate. Using only this capital cost value without factoring in variable operating expenses, a 30-year life expectancy on the equipment, and an assumed emissions reduction of 120 tpy yields a cost- effectiveness value of over $19,000/ton. Equipping this unit with SCR far exceeds EPA's computed average cost of $7,700/ton. Accordingly, it is not cost-effective to control Arthur Kill 20 with an SCR system.

Commenter (0372) appreciates and supports the EPA's recognition of the infeasibility of installing SCRs on low-NO_X combusting CFBs. The EPA is accurate in concluding that SCR technology is not compatible with CFB technology, and the commenter recommends that the EPA provide an affirmative exclusion for CFBs in the rule text.

Commenter (0533) states the EPA is proposing to rely on assumptions regarding the installation of hundreds of millions of dollars in post-combustion control technology at multiple plant sites and at very stringent emissions rates within a very compressed timeframe. The point of a cap-and-trade program is that the affected sources can choose the most cost-effective units to overcontrol and allow expensive or technologically infeasible units to operate with lesser or no controls while meeting the overall state emissions cap. The commenter also states that failure to consider individual circumstances regarding such control technology in crafting state budgets could lead to an unworkable program that results in premature retirements or reduced ozone season operation, thereby adversely impacting grid stability and reliability. It also would be likely to hinder electric generating companies' ongoing transition to expand the role of renewable generation and drive increased costs to electricity consumers. The commenter also states that the proposed FIP overestimates the emissions rates consistently achievable with SCRs and underestimates both the cost and the time necessary for installation of state-of-the art NO_X combustion controls and new SCRs and provides detailed reasoning for the 3 perspectives.

Commenter (0546) states the EPA should provide additional flexibility in state emissions budgets for units with a limited remaining useful life (RUL) beyond 2026 by not presuming SCR retrofits and allowing operators the flexibility to commit to a shortened RUL, along with an exemption for coal-fired units (not already equipped with SCR) from being subject to the proposed daily backstop NO_X emissions rate of 0.14 lb/mmBtu. Rather than presuming SCR retrofits when establishing state budgets, the EPA should instead finalize an alternative budget-setting approach, according to the commenter.

Commenter (0365) states the EPA's cost effectiveness calculations analysis is flawed because of useful life assumptions made. Many units are near the end of life. The commenter also states the EPA's underestimation of the cost of new emissions controls is significant, and results in an attainment strategy that is not achievable by the states. Cost effectiveness may not truly be correlated to emissions reductions.

Response:

The EPA explains in preamble Section V its analysis at Step 3 and in Section VI the implementation of the identified emissions reductions at Step 4. The EPA discussed the incorporation of book life assumptions in its analysis (see EGU NO_X Mitigation Strategies Final Rule TSD) and how this informed our consideration at Step 3 (see preamble Section V.B.1.e).

The EPA also determined that based on comment, the Weston Unit 3 in Wisconsin was already operating at levels commensurate with SCR retrofit (*i.e.*, 0.057 lb/mmBtu in 2021) and it was removed from the segment of the fleet identified as having additional SCR-based emissions reduction potential. The EPA is also finalizing, as proposed, and consistent with commenter's observation, that additional SCR retrofit on CFB units is not cost-effective for that fleet segment at large given both the lower emissions rates of such units and the configuration of such units.

Finally, in regard to comments suggesting the point of a cap-and-trade program is to allow sources to determine their own emissions reduction strategies in response to an average emissions control stringency level informing the applicable emissions budget, the EPA notes that the Group 3 trading program under this rule still allows for this flexibility in compliance.

4.2.1.4 Emissions Rate Assumptions Used for Budget-Setting

Comments:

Commenters (0341, 0372, 0551) state the EPA's proposal to apply a 0.199 lb/mmBtu emissions rate assumption for all unit types is flawed and should be corrected and based on vendor guaranteed capacity. The EPA has not provided the data to support that 0.199 lb/mmBtu can be achieved regardless of coal rank, and the data available in the NEEDS database and the unit specific data for this regulation do not back up this emissions rate. Stakeholders have provided detailed analysis of how considerations such as coal rank can result in large deviations from levels historically demonstrated with this control technology. The EPA has not properly accounted for the small incremental benefit of units with existing combustion controls. For example, Commenter (0341) notes that replacing LNC2 NO_X controls with LNC3 would likely reduce NO_X emissions by less than 10 percent. Technical analysis by the Midwest Ozone Group shows advanced combustion controls are capable of reducing NO_X by replacing legacy burners in existing units, but not to the extent the EPA claims. Commenter (0372) claims that only newer generating units using low burner zone liberation rates can meet these rates, and contends that the NO_X control capability of advanced combustion controls must fully consider coal rank, boiler design features, and operating characteristics. This commenter further claims that the EKPC wall-fired units cannot meet the [proposed] average, but fall within the EPRI range of 0.36-0.46 lb/mmBtu.

Commenter (0342) states that the EPA imposes additional restrictions on well-controlled units and ignores the real-world operations. According to the commenter, the EPA's calculated state budgets assume units with SCRs could be "optimized" to achieve an emissions rate of 0.08 lb/mmBtu, however the commenter's facilities consistently achieve an average NO_X rate lower than this. The commenter concludes that requiring this additional improvement in NO_X control is not justified, especially when sources and sectors in other states remain uncontrolled, and will have very little impact on ozone levels due to the mobile sources in downwind states.

Commenter (0366) states that the EPA's proposed budget allocation relies principally on past operations and assumed emissions rates to set future budgets for EGUs, but the reported rates may represent artificially inflated rates due to reporting requirements. This commenter asserts that the budget setting process potentially shifts the cost of compliance to historically lower-emitting units. The EPA's Dynamic Budget 2023 Template shows historical average NO_X emissions rates that reach as high as 0.054 lb NO_X /MMBtu for 2019-2021 for natural gas fired, combined cycle combustion turbines with between 180 MW and 280 MW capacity. States hosting these natural gas-fired combine cycle turbines equipped with SCR (that likely idled during the 2019-2021 control periods), will receive allowances based on an assumed operating rate of 0.012 lb NO_X /MMBtu with no explanation as to why EGU's like Bethlehem Energy Center's and New Covert Generating Project's EGUs are more cost-effective to control to a lower level on a lb/MMBtu basis than these other SCR-equipped EGU's. Commenter (0366) asserts that the EPA should treat all natural-gas fired, combined cycle combustion turbines equipped with SCRs similarly by using a default emissions rate for all of the affected EGUs unless a specific unit is required to operate at a lower lb NO_X / MMBtu rate during the ozone season under an existing federally enforceable requirement.

Commenter (0408) states the EPA should not set a SOA CC limit that cannot be achieved or guaranteed by the vendor, pointing to 0.199 lb/mmBtu for both wall-fired and tangential-fired coal generating units and claiming that the EPA used flawed data. The commenter estimated the median value of NO_X emissions from tangential-fired boilers firing bituminous coal to be 0.35 lb/mmBtu for LNCFS-II and 0.34 lb/mmBtu for LNCFS-III, with values for the latter option as high as 0.47 lb/mmBtu; yet the EPA cited recent technology with NO_X emissions rates less than 0.10 lb/mmBtu. Commenter (0408) contends that the EPA should remove the SOA CC requirements for units that already have combustion controls installed, or utilize an emissions limit based upon industry standards for the unit's configuration and type of fuel.

Commenter (0323) states that the EPA uses a single emissions rate for Combustion Controls (0.199 lbs/MMBtu) and thus fails to consider fuel and boiler type, which assert an impact on achievable NOx emissions rate. Table 20 (Average Achievable NOx Emission Rates (lbs/MMBtu)) of the commenter's letter presents advised achievable NOx emissions that they recommend be used is establishing emissions attributed to the 2024 budget year.

Commenter (0414) states the EPA proposes to set each unit's benchmark seasonal average NO_X emissions rate as "the higher of (1) 0.10 lb/mmBtu or (2) 125 percent of the unit's lowest seasonal average NO_X emissions in a previous control period" under the CSAPR seasonal NO_X trading program during which the unit operated for at least ten percent of the hours. The commenter states the imposition of such a limitation effectively layers on top of the CSAPR emissions trading program an inflexible, command and control NO_X emissions reduction requirement that is unnecessary for remedying ozone nonattainment problems in downwind states. Furthermore, that inflexible emissions limitation is redundant to the CSAPR assurance provision given that the EPA established the CSAPR “assurance” provisions to limit the degree to which a state could rely on net purchased allowances from other states as a substitute for making its in-state emissions reductions.

Commenter (0533) contends that the EPA’s proposed emissions rates for SCR must be reevaluated, questioning the EPA’s proposal that, on average at coal-fired EGUs, new SCRs can consistently achieve a NO_X emissions rate of 0.05 lb/mmBtu, and existing SCRs, when optimized, can consistently achieve an emissions rate of 0.08 lb/mmBtu. The commenter disagrees with the EPA’s proposed assumption that the NO_X emissions rates are consistently achievable, on average, at coal-fired EGUs, pointing to the NEEDS database and temperature limitations of SCRs.

Commenter (0542) states the FIP improperly estimates the available reductions for RHGF, arguing that a 20 percent reduction in the emissions rate by SNCR may be more appropriate than the proposed dramatic reduction rates, which are not achievable. The commenter points to an apparent error the EPA made in the IPM output RPE files, which estimates “0” projected emissions in 2023 and 2026.

Commenter (0319) contends that the EPA’s budget setting process did not accurately assign NO_X emissions rates to SCR and non-SCR units sharing a common stack. They point to a report that asserts correcting NOx emissions from SCR–equipped units to a lower value increases the NOx tons assigned to the non-SCR-equipped unit, as total common stack emissions must remain the same. It claims, if the non-SCR-equipped unit features state-of-the-art combustion controls, any such revision of assigned NOx tons increases the budget for 2024 and forward years. It further claims, if the non-SCR-equipped unit does not have state-of-the-art combustion controls, the 2024 and forward NOx emissions are adjusted based upon retrofitting the unit with a state-of-the-art emissions factor.

Response:

In regard to the commenter claims that the EPA’s methodology for apportioning emissions that are only measured at a common stack to individual units in its Engineering Analysis results in a downward state emissions budget bias when EPA’s assumes combustion control mitigation measures, those conclusions are incorrect. Contrary to commenters assertion, the EPA makes no assumptions regarding combustion control-based emissions reductions from units with this shared stack configuration where one unit has state-of-the-art combustion controls and the others do not. This includes those listed by commenter Clifty Creek 4 and 5, Ghent 3, Cooper 2, Shawnee 1 and 4, and the EPA did not do so either in the proposal or final rule. In other words, because of unit-level data uncertainty in these cases, the EPA assumes no additional mitigation measures prior to 2026 where it otherwise might exist. (Note: there are only a small number of plants for which this is the case.) Therefore, any bias created by this uncertainty would work in the opposite direction (by overstating, not understating, the state emissions budgets in the years prior to 2026).

The EPA explains its methodology for accounting for uncertainties regarding the emissions rate of units serving a shared stack in the Ozone Transport Policy Analysis Final Rule TSD. It further notes here that for shared stacks, EPA conducts compliance at the facility level so it is based on the reported data summed up to the facility. But for analytics and public access, the data are presented at the unit level, so EPA apportions the data for common and complex stack configurations. The apportionment is based on unit-level heat input. This has no downward impact on the 2023-2025 state emissions budgets, as EPA assumes the emissions from the plant remain unchanged from historical levels.

The EPA does assign SCR retrofit potential to these plants starting in 2026-2027, when emissions reduction potential from SCR retrofits at all units of 100 MW or greater serving shared stacks are incorporated into relevant state budgets under this final rule. If one unit is applied a new SCR rate of 0.05 lb/mmBtu rate and the other has the assumed existing SCR rate of 0.08 lb/mmBtu, then the apportionment of heat input among the two units will influence the state's preset emissions budget in years 2026 and beyond. However, in these years, the EPA will also be using a dynamic budget mechanism that allows for state emissions budgets to be higher than the preset budgets (through 2029). It then fully shifts to dynamic budgets starting in 2030. Dynamic budgets will incorporate updated heat input from years in which sources have the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately. Therefore, any concerns sources may have about shared stack heat input assumptions on their state budgets in years 2026 and beyond may be addressed by actions within the source's control and before they have any meaningful state emissions budget impact. Moreover, sources have not demonstrated any shortfall in state budgets over the extended time period. That is, they haven't illustrated that the forgone reduction potential attributable to non-assignment of combustion control or SCR optimization mitigation measures due to shared stack uncertainty in the 2023-2025 state emissions budgets is more than offset by a future, yet-to-be known, distribution of heat input at multiple units serving a shared stack the conceptually overstates reduction potential.

Commenters' suggestion that the EPA's methodology penalizes units with existing controls that have performed better than the assumed rates (*e.g.*, 0.08 lb/mmBtu) conflates state level budget components with unit level allocation components of the EPA implementation. While the EPA's state budget setting process does assume that units that have outperformed this level of performance in the most recent representative year will continue to do so going forward, that assumption is limited to determining expected state level emissions in the baseline and under the application of the EPA identified mitigation measures. These historical rates do not disadvantage the source when it comes to unit-level allowance allocations. The EPA's unit level allowance allocation methodology would provide two units with the same heat input the same amount of allowance allocations (without exceeding the historical maximum emissions level of each unit). In this scenario of two units that are identical except for one operating their existing SCR control at a rate of 0.08 lb/mmBtu and the other operating its SCR at an emissions rate below that level, the better-performing unit would get the same number of allowances (up to its historical maximum emissions) as the other unit while also emitting less against that initial allocation. As explained in preamble Section VI.B.9, the EPA did adjust – based on comment – its allocation methodology in this final rule to assume units that have not installed or operated their SCR in the past have a historical maximum emissions assumption in the allocation methodology adjusted to match the stringency assumptions used in the state budget process. Hence, such EGUs with historically higher emissions due solely to lack of controls or failure to operate those controls do not, under this final rule, receive higher allowance allocations purely as a consequence of these historical emissions differences compared to units that did have and did operate these controls.

4.2.1.5 Other Comments

Comments:

Commenter (0511) is concerned that the EPA did not follow its own guidance and has chosen to support the proposed rule with simplified modeling procedures in lieu of a standard full photochemical air quality modeling run as it has historically relied upon. The commenter also notes that the rule is unfair to upwind EGUs by implementing additional upwind NO_X restrictions for what has proven to be very minimal, if any, downwind gain (*e.g.*, ozone emissions reductions).

Commenters (0286, 0346, 0385, 0387, 0554) write that the regulatory process should be slowed to conduct further analysis of the potential impacts to electricity reliability and resilience on the national electric grid from the proposed rule. Commenter (0385) adds that this will prevent disproportionate rate increases on rural and minority communities in Texas.

Response:

The EPA performed standard full photochemical air quality modeling for both its base case and final policy case. The geography, stringency, and overcontrol conclusions are all affirmed by this modeling. As in prior rules, the EPA uses AQAT (calibrated to CAMx) to test different increments of reductions and sensitivities at Step 3. See the Ozone Transport Policy Analysis Final Rule TSD for the EPA's description of its use of AQAT and how we ensure our assessment using this tool is calibrated and robust to full photochemical air quality modeling. The basis for our determination of what constitutes significant contribution is discussed in Section V of the preamble. Further response to comment on AQAT is in Section 10.3 (Comments about AQAT).

Comment:

Commenter (0379) responded to the EPA's request for comment on "the assumed performance or emissions rate of the technology, the representative cost, and the timing for installation" as well as "whether other EGU ozone-season NO_X Mitigation technologies should be required to eliminate significant contribution." The commenter writes that combustion add-on emissions reduction technologies are not only feasible but decades old and have been reliably used across the world. The commenter urges the EPA to require the use of SCR controls where feasible, SCR for EGUs utilizing any combustible fuel including natural gas, and the use of SNCR controls for smaller EGUs (including peaking units – small non-CAMD EGUs of less than or equal to 25MW), irrespective of their fuel source. The commenter (0379) adds that in a whitepaper published in 2016 on high electric demand days, the OTC "revealed that peaking units can contribute over 30 percent of total OTR EGU NO_X mass on the episode days that were analyzed, and that a NO_X emissions reduction potential of over 20 tons per day could be realized if gas and oil-fired combustion turbines without installed controls were to meet ‘moderate RACT’ emissions levels. Where they have not already done so, states should adopt NO_X RACT for gas and oil-fired combustion turbines (noting however that RACT must meet technological and economic feasibility requirements).

Response:

Peaker units are addressed in preamble Section V.B.1.g and the EGU NO_X Mitigation Strategies Final Rule TSD.

4.2.2 Non-EGUs

Comments:

Commenter (0303) states that there is currently no demonstrated benefit from California non-EGU source reductions at the monitors in question (Las Vegas Nevada and Yuma Arizona). The commenter provides that the stated benefits were obtained from inconsistent emissions reduction assumptions, invalid modeling, and incomplete documentation.

Response:

The commenter did not provide details or documentation supporting the statement that the benefits were estimated from inconsistent emissions reduction assumptions, invalid modeling, and incomplete documentation.

4.2.2.1 NO_X Emissions Limits

Comments:

Commenter (0336) states for coke ovens (charging) and coke ovens (pushing), the EPA based the emissions limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50 percent based on current permit emissions limits and production-based push/charge cycles. The EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X practices, staged pushing and hood configurations, and potential use of add-on NO_X control technology at larry cars and pushing/charging machines, including potential use of low-NO_X burners, flue gas recirculation, and/or the addition of SCR to mobile hoods and PM control devices. It is unclear from the documentation if any units in the country meet these standards and if so, how they do so. The proposed coke oven and EAF limitations appear to be more stringent than reasonably available control technology (RACT) or BACT requirements across the country. A permit issued in 2022 by the West Virginia Department of Environmental Protection to Nucor Steel West Virginia lists BACT for NO_X from the EAFs as 0.30 lbs/ton of steel. The proposed standard in the FIP for EAFs is significantly lower than the BACT limit in this very recent permit.

Response:

The EPA is not finalizing its proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and

EAFs at this time. Reheat furnaces and certain industrial boilers are the only emissions units within Iron and Steel Mills and Ferro alloying Manufacturing for which the EPA is finalizing requirements. The EPA has provided further responses to these comments in Section VI.C.3 of the preamble.

4.2.2.2 Definition / Clarity on Cost Threshold Applicability

Comments:

Commenter (0336) states the definition provided in the non-EGU memo of known controls would indicate that such technology transfer may not be included in the CoST runs. These assumptions, that SCR or other NO_X control should work on EAFs and coke ovens, may be correct. However, such technology transfers generally increase costs of controls significantly. For example, on EAFs equipped with positive pressure baghouses and without stacks, SCR would need to be installed prior to the baghouse or stacks would need to be constructed. Either situation would increase the cost of the control device beyond what would typically be calculated. It is unclear if the marginal cost threshold of $7,500 per ton includes such technology transfer considerations for EAFs and coke ovens.

Response:

The EPA is not finalizing its proposed emissions limits for EAFs or coke ovens.

4.2.2.3 Cost Threshold Limit

Comments:

Commenter (0398) states the proposed FIP is only attempting to impose emissions limits during the ozone season. Yet, the EPA has calculated cost-effectiveness on an annual basis, instead of ozone-season only. The commenter also states with some cost-effective figures reaching upwards of $20,000 per ton, even the average control costs of $11,000 per ton for SCR at coal-fired EGUs, $7,700 for SCR at oil- and gas-fired EGUs, and $7,500 for blanket controls at what the EPA defines as Tier 1 and Tier 2 sources, are excessive, unfounded, and will have harsh impacts on both energy production and consumer costs during an unprecedented time of inflation and worldwide economic instability. These costs far surpass the $1,600 per ton threshold as seen in the Final Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS, the $1,400 per ton threshold identified in the Cross-State Air Pollution Rule (CSAPR) Update for the 2008 National Ambient Air Quality Standards for Ground-Level Ozone, and DEQ’s compilation of costs deemed acceptable by states and the EPA for Regional Haze Planning Period 1.

Response:

These comments are responded to in Sections V.C and V.D of the preamble, and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).

The EPA also notes that higher cost thresholds used in evaluating controls for EGUs and non-EGUs are appropriate for the FIP because the rule is addressing the 2015 ozone National Ambient Air Quality Standards, which is a more protective ozone NAAQS and may require more costly control technologies to eliminate significant contribution.

Comments:

Commenter (0424) states the EPA does not consider the significant efforts of states in their SIPs to identify reasonable cost-effective thresholds. The EPA's contention that controls are available to comply with the proposed rule at $7,500/ton of emissions or less is, in many cases, unrealistic. Analysis indicates that no controls sufficient to meet the proposed emissions limits are available for many impacted boilers at $7,500/ton or less. Also, SCR is not feasible on many industrial facilities, and its costs well-exceed $7,500/ton.

Response:

These comments are responded to in Sections V.C and V.D of the preamble, and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).With respect to states' efforts in their SIPs to identify reasonable cost-effective thresholds for evaluating controls, as discussed in Section VI.D of the preamble, a state may submit a SIP at any time to address CAA requirements that are covered by the FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate. The EPA would evaluate any assessment of potential controls and related costs from a state as part of the Agency's review of the submitted SIP for compliance with CAA requirements.

Comments:

Commenter (0433) is encouraged that the EPA has selected a more equitable cost effectiveness threshold for EGU's of $11,000/ton and a non-EGU threshold of $7,500/ton. These proposed thresholds more closely reflect Connecticut's regulatory threshold, which is in excess of $13,000/ton. The commenter appreciates that the EPA has proposed a more equitable cost threshold.

Commenter (0509) states the EPA's cost thresholds are overly generalized and cost prohibitive, as the proposed costs to control do not account for fact specific retrofit cases (existing source design and other site-specific factors that may prevent the technical feasibility of a given technology) for each emissions unit. Additionally, the proposed cost thresholds could set a precedent for establishment of BACT or even reasonably achievable control technology (RACT) at extremely high dollar per ton thresholds.

Response:

These comments are responded to in Sections V.C and V.D of the preamble, and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment). In addition, we acknowledge and recognize that many downwind jurisdictions with ozone nonattainment issues have implemented many emissions-control requirements that are well above the costs per ton values identified as reasonable in the identification of significant contribution in this rule. The final rule provides a process for requesting alternative emissions limits in cases of extreme economic hardship, as discussed in Section VI.C of the preamble.

4.2.2.4 General Comments

Comments:

Commenter (0318, 0332, 0527, 0515) supports the inclusion of non-EGU sources in the proposed rule to regulate these sources. Commenter (0332) adds that non-EGUs should contribute significant reductions in any final rule because they are a larger source of precursor emissions. In contrast, commenter (0284) objects to the inclusion of non-EGU sources from relatively high cost, low benefit, and overcontrol standpoints.

Response:

The EPA is including emissions limits for non-EGU industries and emissions units in the final rule.

Comments:

Commenter (0558) is concerned that the 100 ton/year exemption of non-EGU units is too high. The commenter recommends that non-EGU sources less than 100 ton/year be included in rule revisions.

Response:

The EPA's rationale for selecting a 100 tpy applicability threshold for certain non-EGU industries is provided in Section 2.2.3 (Screening Assessment – 100 TPY Threshold) and in Section V.B.2 of the preamble (Non-EGU or Stationary Industrial Source NOx Mitigation Strategies). The EPA's *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) was used to identify potentially impactful industries and emissions unit types for further evaluation. The non-EGU screening assessment memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150. 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.

In addition, the memorandum titled *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"* describes the proposed non-EGU applicability criteria and the relationship between those criteria and the non-EGU screening assessment. This memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0191. The applicability criteria captures some emissions units with actual NO_X emissions below 100 tpy.

To further evaluate the impactful industries and emissions unit types and establish the proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, NSPS rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. This review is detailed in the Proposed Non-

EGU Sectors TSD available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.

4.2.2.5 Inclusion of Municipal Waste Combustors

Comments:

Commenter (0301) states that the EPA's proposal can potentially interfere with the implementation of Minnesota's state solid waste management policy. The EPA's discussion of including MSW sources directly threatens the financial viability of resource recovery facilities. The commenter also recommends exclusion of Municipal Solid Waste Units. Furthermore, the commenter states that the EPA used a baseline, uncontrolled emissions level of 300 to 350 ppm NO_X to evaluate controls. The EPA has restricted NO_X to 150 ppm under the Section 129 Municipal Waste Combustor standards for new sources. The Minnesota Resource Recovery Association sources regulated under existing Section 129 standards are also typically operating well below the 300 to 350 ppm emissions level that was selected by the EPA to evaluate control cost-effectiveness. The EPA's baseline assumptions overestimate NO_X emissions and do not appear to be accurate for Minnesota Resource Recovery Association's member facilities.

In contrast, commenters (0318, 0367) state the EPA should not exclude certain non-power plant sources such as municipal waste combustors that produce a substantial amount of NO_X that could be reduced at reasonable cost.

Commenter (0416) believes the EPA should consider other NO_X mitigation strategies from local sources like simply cycle combustion turbines, municipal waste combustors, and distributed generation. These sources are known to be causing nonattainment or maintenance problems in their own areas.

Response:

For the reasons provided in the preamble at Section V.B.3.a (Municipal Solid Waste Units) and Section VI.C.6 (Municipal Waste Combustors) and in the Final Non-EGU Sectors TSD, the EPA is finalizing regulatory requirements for MWCs located in the 20 states covered by the FIPs for non-EGUs. Although the EPA had proposed to include Minnesota among the states subject to non-EGU control requirements, the final rule does not include Minnesota among these states.

4.2.2.6 Inclusion of Other Sources and Fuels

Comment:

Commenter (0283) states the proposed Plan does not account for the net emissions benefit provided by the combustion of fuels – *e.g.*, biomass combustion. For this reason, the commenter proposes that biomass combustion be exempted from ozone-season emissions requirements or that the reduction to lifecycle emissions afforded by the combustion of biomass be accounted for by some other acceptable means. Additionally, the commenter is concerned that the Plan penalizes past high-performance NO_X removal. The Plan bases emissions standards for some units on a reduced emissions rate of 0.16 lb/mmBtu. This is less stringent than the commenter's current limit, before implementation of the Plan. Units already operating under a stricter limit will face diminishing efficiency of emissions reduction strategies making the even lower emissions rates used in the Plan much more difficult to consistently maintain.

Response:

The final rule does not include emissions limits for non-EGU emissions units burning biomass fuels.

Comment:

Commenter (0324) states that emissions units that adequately demonstrate actual emissions significantly less than 100 tpy should be subject to less burdensome compliance requirements or be excluded from the rule. The commenter suggests the EPA should use a regulatory approach adopted for reasonably available control technology standards; allow exemption from this rule, with "once-in-always-in" provisions, for units that annually demonstrate low actual emissions before control, or, as an alternative, the EPA should reduce the monitoring and reporting requirements on these sources.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

Comments:

Commenter (0437) discusses feasibilities of different control technologies and concludes that it is not reasonable to expect pulp and paper mills to replace all combustion of biomass with natural gas because forest products facilities rely on combustion of carbon neutral, biomass residuals from their processes to remain economically sustainable and to keep GHG emissions low. The commenter then states that biomass boilers cannot meet the NO_X emissions levels proposed by the EPA for other fuel types and the EPA should not include pulp and paper mill boilers firing greater than 10 percent biomass (annualized heat input basis) in this rule. The commenter also states that the EPA has proposed ozone-season NO_X emissions limits for pulp and paper boilers that are more stringent than NSPS and most RACT programs, particularly for multi-fueled boilers. The proposed limits will result in challenging retrofit projects for many facilities. The commenter also states based on its own analysis that there will be more impacted units and less reduction than those proposed. The commenter also states the EPA should allow case-by-case RACT.

Commenter (0518) states the EPA should not expand the scope of fuels for industrial boilers that may be subject to controls.

Response:

In the final rule, the EPA is including single-use fuel limits for boilers using coal, residual oil, distillate oil, and natural gas. Specifically, boilers that burn 10 percent or more of fuels other than coal, residual or distillate oil, natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements contained within the final rule. Lastly, the final rule allows a facility owner to submit a request for a low use exemption that restricts the boiler from operating more than 10 percent of the year. If the EPA grants the request, the boiler will be excluded from the final FIP's requirements. For more details, see Section VI.C.5 of the preamble.

4.2.2.7 SCR Installation / Retrofit

Comments:

Commenter (0340) states that, prior to issuing the proposed rule, the EPA did not request additional information regarding NO_X emissions, actual operations, and potential control strategies from non-EGU industries, instead relying on state regulations and permits for control scenarios, without verifying that they were successful or installed. SCR specific technology is old and the majority of sources requiring SCRs installed them long ago. Given the EPA's selection of SCR as a control strategy for multiple industries in the proposed rule, and the potential number of subject units, the EPA has significantly underestimated the availability of equipment and vendors. The lack of available vendors and equipment will hinder facilities in complying with the extremely short deadlines that the EPA proposes in this rule. The EPA has not evaluated or considered the actual day-to-day operation process, which is generally a batch-type process, and is not suited for SCR controls.

Response:

In response to comments on the EPA's proposed non-EGU emissions limits, the EPA re-assessed potential emissions units and control options for industrial sources. This assessment is documented 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 also initiated a study called *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* to assess the timing needs for installation of controls on non-EGU sources and related availability of vendors, equipment, and materials. The final rule includes a provision that allows the owner or operator of an existing affected unit to request a limited compliance extension if it is unable to comply with the requirements of the final rule by May 1, 2026, due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by the applicable compliance date. See Section VI.A.2.b of the final rule preamble for additional details.

Comment:

Commenter (0356) states the EPA may be underestimating the costs for SCR in the Glass and Glass Product Manufacturing Industry. Additionally, there may be other facilities in the glass industry that would be subject to the proposed rule and could achieve comparable NO_X reductions at significantly lower cost through technologies other than SCR.

Response:

It appears the commenter is referring to proxy results presented in the EPA's *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment). The primary purpose of the non-EGU screening assessment was to identify potentially impactful industries and emissions unit types for further evaluation. The non-EGU screening assessment memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150. 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. This analysis was not intended to support a conclusion that SCR should be required for any given industry. For the Glass and Glass Product Manufacturing Industry, the emissions limits in the final rule can generally be met through installation and operation of low-NOx burners on all glass furnaces covered by the final rule.

Comments:

Commenter (0360) agrees with other cited commenters that SCR controls are technically infeasible for EAF and Ladle Metallurgical Furnaces (LMFs), noting that SCR has never been used or proven as a NO_X control in an EAF and is not feasible due to the batch nature and variability of operations and associated emissions. The commenter cites other comments, which note that the feasibility analysis relies on outdated information, is infeasible, and would lead to overcontrol.

Response:

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, and EAFs at this time. Reheat furnaces and certain industrial boilers are the only emissions units within Iron and Steel Mills and Ferro alloying Manufacturing for which the EPA is finalizing requirements. These comments are further responded to in Section VI.C.3 of the preamble.

4.2.2.8 NO_X Emissions Reduction Assumptions

Comment:

Commenter (0295) states the proposed FIP does not identify specific non-EGU facilities proposed for control and that the EPA may have overestimated potential emissions reductions from the cement sector.

Response:

The EPA was not required to identify specific facilities that would be subject to the FIP as proposed or finalized. The EPA prepared the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) to identify potentially impactful industries and emissions unit types for further evaluation. The non-EGU screening assessment memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150. 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.

The memorandum titled *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"* describes the proposed non-EGU applicability criteria and the relationship between those criteria and the non-EGU screening assessment. This memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0191. The EPA used the non-EGU screening assessment to identify impactful industries (identified in Step 1 of the analytical framework presented in the non-EGU screening assessment) but did not directly use the proxy estimates for emissions unit types, emissions reductions, and costs from the non-EGU screening assessment to establish applicability thresholds and emissions limits in the proposal. The memorandum titled *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"* describes the proposed non-EGU applicability criteria and the relationship between those criteria and the non-EGU screening assessment. This memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0191.

We provide a more detailed discussion of the non-EGU screening assessment and the EPA's evaluation of potential emissions reductions from non-EGU industries in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment), and we respond to additional comments claiming that the EPA has overstated the potential ozone season reductions available from the non-EGU sector in Section 2.3.6 (Other Comments).

Comment:

Commenter (0300) states the EPA draws an illogical conclusion that the decreases in NO_X contributions from non-EGU sources presented in this proposed rule (Table VI.C.2-1, page 20090) is a "meaningful air quality improvement." It appears misleading to sum the ppb improvements across all receptors and present this as the emissions reductions estimated for downwind receptors. The total improvements estimated from Tier 1 and Tier 2 non-EGU sources across 111 downwind receptors was only 5.161 ppb. This could hardly be considered a "meaningful air quality improvement" with an average improvement of 0.046 ppb per receptor, 0.07 percent of the 70 ppb NAAQS. Furthermore, the commenter states the EPA arbitrarily established maximum contributions for determining "potentially impactful industries" for purposes of identifying and establishing NO_X emissions limits for non-EGU sectors.

Response:

4.2.2.9 NO_X Emission Limits

Comments:

Commenter (0294) states that the EPA suggests flue gas treatment will be necessary for the Iron and Steel Mills and Ferroalloy Manufacturing industry to achieve the proposed emissions limits for this industry and that combustion strategies alone will not be sufficient to meet the proposed limits. Using the CoST model (including many of its default data values), the commenter estimates that the cost effectiveness to comply with the proposed rule is significantly above the EPA's cost threshold.

Commenter (0764) states non-EGUs, including Tier 2 sources in Arkansas, are being capriciously saddled with inflexible limits. The lack of a trading option makes the EPA's decision to establish emissions limits based on screening level economic data indefensible. And the EPA's cost estimates are inaccurate for the proposed emissions sources, as each unit must meet a specific emissions limit based on screening, a highly caveated analysis.

Response:

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, and EAFs at this time. Reheat furnaces and certain industrial boilers are the only emissions units within Iron and Steel Mills and Ferro alloying Manufacturing for which the EPA is finalizing requirements. For reheat furnaces, the final rule requires the use of low-NO_X burners (LNB) or equivalent low-NO_X technology that achieves at least a 40 percent reduction from baseline NO_X emissions.

The commenter is incorrect that the final emissions limits and other requirements for non-EGU industrial sources in this final rule are based only on a screening-level assessment. As discussed in Section V of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment), the non-EGU screening assessment served a limited but useful purpose in narrowing down the list of industries that are impactful on downwind air quality and should be further analyzed for cost-effective emissions control opportunities. In the proposal materials, we reviewed these industrial sources and relevant units in more detail before proposing emissions control requirements. In response to comments and with further updated information, in this final rule we have adjusted the emissions control requirements to reflect a reasonable degree of stringency, based on widely achieved emissions performance at similar facilities and using established NO_X control technologies.

Comment:

Commenter (0347) states the EPA cannot demonstrate that the production-based limits proposed for wet and precalciner cement kilns in Pennsylvania are necessary. The commenter states that the Pennsylvania SIP contains year-round NO_X limits for long wet and precalciner kilns of 3.88 lbs NO_X/ton of clinker and 2.36 lbs NO_X/ton of clinker, respectively, for major sources of NO_X, and that the EPA should establish an exemption for cement kilns that are already subject to more stringent production-based NO_X limits.

Response:

With respect to the commenter's claim that the EPA should establish an exemption for cement kilns that are already subject to more stringent production-based NO_X limits, we note that, generally, any source subject to a state requirement that is more stringent than the emissions limit in this final rule should not need an exemption as compliance with the more-stringent state requirement can be used to demonstrate compliance with the emissions limits in the final rule. During the ozone season, however, the emissions limit in this final rule for precalciner kilns (see Table VI.C-2 of the preamble) is more stringent than the emissions limit identified by the commenter that applies in Pennsylvania. As explained in Section V.D. of the preamble, the EPA has concluded that the emissions limits in this final rule are set at an appropriate level of control stringency to collectively eliminate significant contribution to downwind nonattainment and maintenance receptors, and that the emissions control strategies identified and evaluated in Sections V.B and V.C of the preamble are widely available and in use at many non-EGU sources across the country.

Comment:

Commenter (0397) requests clarification on whether emissions limits for non-EGU sources are only applicable during ozone season.

Response:

The emissions limits for non-EGU sources are only applicable during ozone season.

4.2.2.10 Compliance Flexibility

Comments:

Commenters (0338, 0518, 0519, 0528) state the EPA should include provisions that allow states and sources flexibility in how they achieve asserted emissions reduction goals – *e.g.*, through the installation of controls, fuel switching, or another method, rather than impose rigid requirements. Commenter (0518) also states the EPA's proposed limits for non-EGU sources should not be more stringent than counterpart NSPS. Commenter (0528) specifically states that to match the same flexibility that EGUs have been granted in prior rules, the EPA should allow non-EGU sources to utilize emissions averaging to meet NO_X emissions reduction requirements.

Response:

The EPA disagrees with the claim that the emissions limits for non-EGU sources should not be more stringent than the NSPS. The purpose of the final rule is to eliminate significant contribution from emissions sources in upwind states to downwind nonattainment and maintenance receptors for the 2015 ozone national ambient air quality standards, consistent with the requirements of CAA section 110(a)(2)(D)(i)(I). Section 110(a)(2)(D)(i)(I) does not prohibit emissions limits established under that section from being more stringent than NSPS. In response to comments, the final rule includes provisions that allow any owner or operator of a facility containing more than one reciprocating internal combustion engine in the pipeline transportation of natural gas industry to request EPA approval of a Facility-Wide Averaging Plan, which would allow the owner/operator to use emissions averaging across multiple engines to meet the requirements of the final rule. Section VI.C.1 of the preamble provides a more detailed discussion of the provisions governing Facility-Wide Averaging Plans.

Comments:

Commenter (0518) suggests that the EPA apply a consistent emissions threshold for non-EGUs and provide units an applicability mechanism similar to a "synthetic minor" source and urges the EPA take two steps regarding non-EGU sources. First, all categories should be subject to an emissions threshold, not a capacity or other threshold. Second, for all sources, the EPA should confirm that sources have the ability to minimize their emissions (or their capacity or other metric that the EPA may retain for applicability) and thereby avoid the control requirements. The commenter also states that a requirement for continuous emission monitoring system (CEMS) from non-EGUs is overly burdensome and infeasible for certain sources.

Commenter (0549) states that to avoid overly burdensome or duplicative requirements, the EPA should consider a range of compliance alternatives for non-EGUs, such as the use of predictive emissions monitoring systems instead of CEMS or compliance with a comparable regulatory program. The commenter then recommends that the EPA exempt facilities that may operate under comparable regulatory programs from the proposed FIP requirements. Currently, 40 CFR 52.45(d)(2) requires that facilities with affected boilers conduct NO_X emissions monitoring for 30 consecutive operating days. Given the potential overlap with other programs' requirements, we recommend that the EPA clarify in the final rule that the 30-day initial compliance test would not be required in cases where the owner/operator already has a NO_X CEMS monitor in service.

Commenter (0631) argues that a predictive emissions monitoring system (PEMS) is sufficient and should be applied to each non-EGU source category to allow compliance with NO_X emissions reduction requirements.

Commenter (0631) compares costs of CEMS and PEMS in terms of capital cost, maintenance cost, cost of quality assurance, and labor cost and suggests that PEMS are more cost-effective. The commenter notes PEMS require much less energy to run the computer than the heated sample lines, heated probe, and HVAC for the environmentally controller shelter for the CEMS. PEMS do not require cylinder gases for calibration. The costs associated with replacement of cylinder gases, the fuel to deliver the gas bottles and to take the empty bottles away are also avoided.

Commenter (0631) notes the single most burdensome piece of the implementation program for PEMS to be used in CAMD programs is the requirement to obtain EPA approval for each PEMS deployed under the part 75 program. Having the non-EGUs not be included in the part 75 trading program will help streamline the process of implementation of PEMS. 40 CFR part 60, PS-16 provides a pathway for certification of PEMS to be used for compliance with NSPS standard and allows source operators to deploy PEMS without direct approval from the regulatory authority. This allows source operators to install and certify PEMS in an efficient manner and to mitigate costs associated with the approval process. Under current CAMD programs, part 75 PEMS must undergo a subpart E demonstration in which a temporary CEMS is deployed and operated alongside the CEMS for a period of 720 operating hours or about one month. The subpart E demonstration validates the installed PEMS and ensure that the PEMS is providing data with the same accuracy, reliability, and timeliness of a comparable CEMS. Once the subpart E demonstration is completed, a petition is made to EPA to approve the PEMS installation and use for the source monitoring application. Additionally, the commenter notes the costs of conducting the subpart E demonstration are significant and can be prohibitive for installation of PEMS on some sources. Sources that operate intermittently for example such as peaking units, can take substantially more time to certify than units that are base loaded and run days, weeks, and months continuously. During the time of the demonstration, there must be a temporary CEMS installed and operated at great cost. The commenter proposes that the EPA consider limiting the time that the EPA has to respond to the petition after completion of the initial subpart E demonstration and submittal. Source owners should have to wait no more than 180 days to receive a response to a petition.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

4.2.2.11 Overcontrol

Comment:

Commenter (0350) states the EPA underestimates the number of affected engines, resulting in an underestimate of emissions reductions and unlawful over-control and provided examples of its own facilities. The commenter also requests that the final rule exempt emergency engines.

Response:

The EPA has included updated estimates of engines subject to the final rule as discussed in Section V.C.2 of the preamble. Comments regarding the changes to the engine's applicability criteria are addressed in Section VI.C.1 of the preamble. The rule does not result in overcontrol. *See* Section V.D.4 of the preamble.

4.2.2.12 Other Comments

Comments:

Commenter (0321) states it is infeasible and inappropriate to phase out and retire existing glass manufacturing furnaces and replace them with all-electric melter installations. While all-electric ("cold top") furnaces are currently in use in the container glass industry and are limited to very specific glass formulations (clear, green), the current state of technology within the float glass manufacturing sphere does not allow for glass of sufficient quality to be manufactured for automotive or architectural glass applications using all-electric glass furnaces. It is also currently technologically impossible to produce grey/privacy glass of any quality using cold top/all-electric glass furnaces. Barring a major unforeseen technological breakthrough within the float glass industry, the implementation of all-electric float glass manufacturing is simply not possible.

Response:

EPA is not establishing any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time.

4.2.3 Other Stationary Sources

Comments:

Commenter (0758) states the seventy million buildings across the country that burn oil or gas in appliances emit 425,000 tons of NO_X pollution annually, according to the EPA's 2017 National Emissions Inventory. In states covered by the proposed transport rule, buildings emit 300,000 tons of NO_X every year—more NO_X than any of the industrial sectors covered by the proposed rule. In California, Nevada, New Jersey, and New York, buildings emit more total NO_X than power plants and all covered industrial sectors combined. The commenter notes given the modesty of the NO_X emissions reductions currently proposed, the EPA cannot afford to leave an entire sector of ozone pollution sources off the table. The EPA should consider requiring NO_X emissions reductions from buildings, and, as a first step, should model the impact on downwind ozone levels from such emissions.

Commenter (0758) continues, electrification–that is, using electricity to power heating and cooking appliances instead of fossil fuels–or adoption of low-NO_X appliances are widely available, cost-effective ways to reduce NO_X emissions from buildings. Switching to all-electric for new appliance sales by 2030 could avoid more than 500,000 tons of NO_X emissions, 14,400 tons of $PM_{2.5}$ emissions, and 3,750 premature deaths each year by 2045. In states covered by the proposed transport rule, buildings emit 300,000 tons of NOx every year—more NOx than any of the industrial sectors covered by the proposed rule. Electric appliances like air-source heat pumps and heat pump water heaters are highly efficient (two to four times as efficient as their fossil fuel-fired counterparts). The commenter argues electric appliances are widely available and increasingly cost- competitive. Already, these appliances have lower net present costs than fossil fuel appliances for new construction, when replacing propane or heating oil appliances, and when simultaneously replacing furnaces and air conditioners. The EPA's own Menu of Control Measures identifies low-NO_X furnaces, water heaters, and space heaters as having far lower abatement costs than the proposed rule's $7,500 per ton screening threshold and lower than a number of the proposed emissions reduction measures. 87 Fed. Reg. at 20,091.

Commenter (0758) concludes given the significant NO_X emissions from buildings in upwind states and need to further reduce emissions to protect the air quality of downwind states, the EPA should assess ozone transport from building emissions, expand and update its emissions inventories with respect to pollution from buildings, and consider requiring reductions in NO_X emissions from buildings in the final rule.

Commenter (0358) supports the EPA in including non-EGUs in the proposed rule and optimizing the use of existing emissions control technology at power plants but urges EPA to also include NO_X emissions from buildings in the Transport Rule. According to the commenter, buildings emit significant amounts of NO_X that are comparable to and in some cases greater than emissions from sources covered by the Transport Rule and using electricity to power heating and cooking appliances instead of fossil fuels is an available, cost-effective way to eliminate direct building emissions. The commenter reports that in states covered by the Transport Rule, buildings emit 300,000 tons of NO_X per year, which is several times higher than the annual NO_X emissions from any single industrial sector covered by the proposal and is about 61 percent of the non-EGU and 38 percent of the EGU total annual NO_X emissions. The commenter remarks that building electrification has the potential to reduce NO_X emissions by hundreds of thousands of tons and cites several studies, including the National Renewable Energy Laboratory's (NREL's) high electrification scenario, under which nationwide NO_X emissions from buildings are estimated to decrease by nearly 275,000 tpy. The commenter also notes that building electrification would also have other benefits, such as reducing greenhouse gas (GHG) emissions and indoor air emissions. The commenter mentions that there is significant precedent for addressing building pollution through regulatory mechanisms like zero-or low-NO_X emissions appliance standards, which could be incorporated into the Transport Rule. The commenter concludes that since buildings in transport rule states emit significant amounts of NO_X emissions and cost-effective measures for reducing these emissions are readily available, the EPA should analyze building emissions in its final rule and require measures to reduce ozone pollution from buildings.

Commenter (0261) states that the following sources of NO_x, VOC, ROG, PM and ozone formation should be included in this regulation: Biomass and biofuel energy, flaring (from fracking), excess application of NO2 fertilizers, crematoria, small off-road engines (landscape equipment, generators, agricultural equipment), refineries, metal, and steel.

Commenter (0379) urges the EPA to cover all combustible fuel types with provisions for operational adaptation and optimization for innovation and best practices, since thermal NO_x is the major mechanism of NO_x production, and it is independent of fuel type. The commenter suggests this for both EGU and non-EGU sources of NO_x emissions.

Response:

Thank you for your comment. The commenter does not provide sufficient details on either the cost or feasibility of implementing these types of emissions reductions or establish that it would be possible to do so by the analytical years relevant to this action. The EPA recognizes that there may be substantial NO_X emissions reduction potential through appliance electrification over the longer term (e.g., commenter's data looks at 2045), but currently does not have the detailed datasets needed to assess broad-scale electric appliance adoption for consideration in the final rule. The EPA does not include low-NO_X furnaces, water heaters, and space heaters in the September 2022 version of the Menu of Control Measures.

The EPA acknowledges that there are many other anthropogenic sources of NO_X emissions in upwind states than are covered in this final rule. The Agency implemented a reasonable methodology to focus on the most impactful NO_X emissions-reduction opportunities in industries beyond the power sector. The Agency has explained how this evaluation is consistent with the 4-step interstate transport framework and has allowed for the identification of a set of emissions reductions in upwind states that, taken together, eliminate “significant contribution” to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS. Comments calling for the regulation of other sources of NOx emissions generally lack reasonably specific evidence that would justify targeting these sources of emissions reductions rather than the emissions sources covered in this rule. We note that states have the opportunity to replace this FIP with a SIP targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP, as discussed further in Section VI.D of the preamble.

4.2.3.1 Support for Including Other Stationary Sources in the Rule

Comment:

Commenter (0318) expresses concern about the EPA’s proposed continuance of exempting small EGUs from the proposed FIP, noting the existence of about 24,800 MW of small EGU capacity in the states covered in the proposed FIP and the OTR states combined, which is the equivalent capacity of 24 large 1000 MW powerplants. The commenter suggests that, with the warranted increasing compliance costs for larger EGUs, the exemption fosters a potential leakage problem by creating greater incentives to shift increasing generation shares across numerous smaller EGUs during the ozone season. This incentive will be a particularly harmful outcome if the shifts occur on the highest ozone days.

Response:

The EPA does not agree that increased compliance costs for covered EGUs will create a serious concern of shifting generation to sources under 25 MW. The EPA’s IPM analysis of the base case and the final policy case illustrates no substantial emissions leakage to units less than 25 MW. When looking at emissions from sources less than 25 MW, the EPA determined that nationwide emissions only increased approximately 1,000 tons (or approximately .3 percent from) from sources less than 25 MW.

Comment:

Commenter (0328) supports the EPA’s proposed non-EGU limits for certain source categories as well as the development of a standard for MSW incinerators in the Proposed Transport FIP but has concerns about how the limits being proposed may impact NO_X reductions and transport issues that go beyond the ozone season. If the non-EGUs were allowed to participate in limited trading by buying and surrendering allowances for excess emissions, EGUs participating in the trading program would then be able to make additional cost-effective reductions to address any excess emissions generated by the non-EGUs.

Response:

Thank you for your comment. See Section VI.C of the preamble for the EPA’s response to comments regarding inclusion of non-EGU emissions units in the allowance-based trading program updated by this rule. The final rule does not include non-EGU emissions units in the trading program.

Comment:

Commenters (0433, 0757) state that consideration of non-EGU sources is too narrow in scope and does not meaningfully affect Connecticut's ozone values. The commenters recommend expansion of scope to include MWC, airports, and further reduction from mobile sources.

Response:

The EPA included emissions from aircraft and ground support equipment in the point source emissions inventory used for this rule. Based on the non-EGU screening assessment conducted for this rule, the EPA did not identify airport-based emissions as a cost-effective means for achieving meaningful impacts on downwind receptors. For this reason, the EPA is not including airports as industrial sources covered by this rule. The EPA is finalizing emissions limits for MWCs in this rulemaking as described in Section VI.C.6 of the preamble. Responses to comments regarding the inclusion of mobile source emissions reductions are provided in Section 4.2.4 (Mobile Sources).

Comment:

Commenter (0510) states that cost-effective controls on the MSW incinerators (MWC) sector could result in considerable additional emissions reductions and benefit the NYMA receptors that are projected to have remaining nonattainment and maintenance issues after implementation of the proposed rule. Existing federal requirements for MWCs allow for significant additional reductions. Based on the OTC workgroup's RACT-style evaluations, the commenter suggests that emissions rate limits of 105 ppmvd on a 30-day averaging basis and 110 ppmvd on a 24-hr averaging basis are technologically achievable and economically feasible for many MWC configurations.

Response:

The EPA is finalizing emissions limits for MWCs in this rulemaking as described in Section VI.C.6 of the preamble.

Comment:

Commenter (0301) asks that the EPA clarify what specific class of units the EPA is considering for inclusion in the final rule – Solid Waste Incinerators, Municipal Solid Waste Units, and Municipal Waste Combustors.

Response:

The final rule identifies the type of incinerators anticipated to be covered by the final rule as discussed in Sections V.B.3.a and VI.C.6 of the preamble.

Comment:

Commenter (0558) states, regarding the proposal not including units rated at 25 MW or less, that while the small EGU emissions may not be a large part of the seasonal total, they may be a non-trivial portion during the short periods associated with ozone episodes. The EPA should, at a minimum, fully evaluate the impact of NO_X emissions from the smaller EGUs during short term ozone exceedance events and whether controls are justified, before excluding these small EGUs from the proposed rule, according to the commenter.

Response:

The EPA's analysis indicates that less than 6 percent of nationwide emissions come from sources rated at 25 MW or less. The commenter did not provide sufficient information to support the claim that NO_X emissions from EGUs with nameplate ratings of 25 MW or less may represent a higher, or "non-trivial" proportion of NO_X emissions during high ozone days. The EPA continues to find that these sources offer low potential reductions, have a higher reduction cost per ton relative to other sources covered by this rule, and would have other monitoring and compliance burdens associated with regulation under this rule. Consistent with the rationale in the proposed rulemaking, the EPA is continuing to apply the 25 MW applicability threshold for EGUs in this rulemaking.

Comment:

Commenter (0558) asserts that the higher levels of efficiency associated with some cogeneration units does not provide justification for excluding cogeneration from the EPA's proposed rule. Combined cycle EGUs have overall efficiency values similar to cogeneration units, yet the EPA does not propose to apply the same consideration to the combined cycle units. The environmental impact of one ton of NO_X from a 60 percent efficient cogeneration unit is no different than one ton of NO_X from a 33 percent efficient combined cycle EGU. The commenter notes further that cogeneration units have largely been exempt from requirements applicable to EGUs and therefore have not been required to control NO_X emissions as a result of these trading programs. But cogeneration units by definition generate electricity that is either sold off-site or used to offset electricity that would otherwise have to be purchased from offsite electric generators. The commenter explains that cogeneration units may vary their operation in response to electric grid economic signals, similar to electric utility EGUs. In this regard, their operation in response to grid demand may be no different than the electric utility EGUs on any particular ozone season day when those emissions may contribute most to ozone events. It does not seem reasonable that cogeneration sources are permitted to continue to enjoy this advantage when they tend to operate in response to energy demands during the ozone season and at times when their emissions could be expected to contribute to an ozone event. Therefore, Commenter (0558) recommends reconsideration of the proposed exclusion of cogeneration units from the proposed rule. The commenter also states a recent draft report prepared by the OTC, ''Municipal Waste Combustor Workgroup Report," which the EPA cites in the proposal, has identified the availability of multiple technically feasible and economically justifiable NO_X control technologies, or groups of individual NO_X control technologies, that can achieve significant NO_X reductions from existing municipal waste combustion units. Commenter (0558) recommends that the EPA require MWC units to comply with emissions rates of 105 ppmvd on a 30-day averaging basis and 110 ppmvd on a 24-hr averaging basis, regardless of size.

Response:

The commenter's claim that small EGU sources rated at 25 MW or less have emissions that may contribute most to ozone events is not grounded in evidence. The fact that cogeneration units may vary operation in response to demand signals from the electric grid does not provide a factual basis for the EPA to determine that these sources are disproportionately contributing NO_X emissions to downwind receptors on high ozone days. In fact, the EPA's analysis indicates that less than 6 percent of nationwide emissions come from sources rated at 25 MW or less. The EPA is retaining the applicability threshold of 25 MWs for EGUs in this rule.

The EPA evaluated the OTC report cited by the commenter and is finalizing the emissions limits described in Section VI.C.6 of the preamble for Municipal Waste Combustors.

Comment:

Commenter (0757) states that, for MWCs, the EPA should set emissions limits based on assumed installation of SCR technology. SCR is widely used in the industrial sector and currently installed at the Palm Beach Renewable Energy Facility to meet a 50 ppm NO_X emissions limit. The commenter asserts that the EPA should prioritize a 24-hr NO_X limit, and set this 24-hr limit at 50 ppm. The commenter contends that there is no justification for failing to set limits for large MWCs that are at least as strong as the limits of 110 ppm on a 24-hr average and 105 ppm on a 30-day average that are identified in the OTC report so long as the operators of individual facilities are given the opportunity to submit facility-specific information demonstrating that a particular MWC is unable to meet the limit. MWC operators should be allowed to submit facility-specific information demonstrating that a particular MWC cannot meet the new limits at or below the cost-effectiveness threshold in the EPA's final rule, according to the commenter. The commenter claims that the retrofit of MWC emissions controls would not take longer to implement than the 2026 ozone season. Finally, Commenter (0757) notes that it would be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs, because all large MWCs are already required to use CEMS to demonstrate compliance with NO_X limits.

Response:

The EPA evaluated potential installation of SCR control technology at MWCs and determined that SCR installation at MWCs covered by this rule would not be a cost-effective means of reducing NO_X emissions impacting downwind receptors. The EPA also evaluated the appropriateness of different emissions limits for multiple types of averaging periods, including 24-hr and 30-day average emissions limits. The EPA is finalizing emissions limits for MWCs in this rulemaking as described in Section VI.C.6 of the preamble. The monitoring and reporting requirements for MWCs are listed under "Compliance Assurance Requirements" in the same section.

4.2.3.2 Support for Exempting Sources with 25 MW or Less

Comment:

Commenters 0305, 0411, 0419, 0421, and 0760 supported the EPA's proposal to exclude sources with 25MW or less.

Specifically, commenters 0305, 0411, and 0419 provide the following rationale: (1) Historically, NO_X controls for these small utilities have not been justified, (2) Retrofit NO_X controls are still neither cost effective nor technically feasible for existing intermittently operated small boilers, and (3) There will be high monitoring and other compliance burdens. The commenters conclude that an insignificant fraction of NO_X emissions come from these types of intermittently operated smaller units and the costs of additional controls outweigh any minimal benefit to the attainment status of downwind states.

Response:

Consistent with the rationale in the proposed rulemaking, the EPA is continuing to apply the 25 MW applicability threshold for EGUs in this rulemaking. The EPA continues to find that these sources offer low potential reductions, have a higher reduction cost per ton relative to other sources covered by this rule, and would have other monitoring and compliance burdens associated with regulation under this rule.

Comment:

Commenter (0411) agrees with the EPA's historical precedent of including only those EGUs greater than 25 MW in size in allowance trading programs, and also asserts that MSW incineration Units should not be included in this rule. Solid waste incineration accounts for less than 1 percent of statewide NO_X emissions and these units include a variety of combustion processes. Each of these processes have different combustion technologies and no one-size-fits-all NO_X control technology is cost-effective for all these combustion processes. These units are already heavily regulated under state or federal Municipal Waste Combustor regulations. These facilities also provide the significant environmental co-benefit of diverting solid waste from being landfilled. As referenced in the MPCA solid waste management hierarchy, incineration and waste-to-energy is the preferred option for disposal of waste following recycling and reuse methods. The commenter concludes that because of their size and important environmental co-benefits, these units should not be included in the final rule.

Response:

See preamble, Section V.B.3.a, *Municipal Solid Waste Units.* The EPA notes that MWCs less than that small MWCs that combust less than 250 tons per day of municipal solid waste are not included in this rulemaking.

Comment:

Commenter (0421) asserts that the EPA is correct that cogeneration units offer considerable environmental benefits such as (1) Requiring less fuel to produce a given energy output; (2) Providing higher total system efficiencies (60 percent or greater for producing electricity and useful thermal energy); (3) Emitting less criteria pollutants and greenhouse gases; and (4) Offering increased reliability of and local access to electrical power.

Response:

Comments regarding the environmental benefits of cogeneration units are not within the scope of this rulemaking.

4.2.3.3 Other Industrial Sources of NO_X

Comment:

In response to the EPA's request for comment on our sources of NO_X including MSW incinerators, Commenter (0336) lists 2019 data from industries with "sizeable" NO_X emissions. This list includes a MSW incinerator with NO_X emissions over 1,000 tpy that is nonetheless considered small enough that Section 129 standards did not require SNCR NO_X controls, and that is outside Virginia's OTR and are not subject to NO_X RACT requirements.

Response:

The EPA is finalizing emissions limits for MWCs in this rulemaking as described in Section VI.C.6 of the preamble.

4.2.4 Mobile Sources

Comments:

Commenters (0235, 0279, 0281, 0320, 0323, 0331, 0359, 0372, 0402, 0405, 0409, 0416, 0437, 0539, 0541, 0550, 0559, 0758, 0760, 0764) state that emissions from mobile sources are a significant contributor to ozone, including from cars and trucks, as well as trains, ships, and planes. While stationary sources, including power plants, still contribute significantly to interstate ozone pollution, mobile sources are now the largest contributor of ozone-forming pollution in the Northeast. The commenters believe the EPA must require emissions reductions from non-power plant sources, including mobile sources.

Commenters (0402, 0559) indicate, as the proposed rule recognizes, the transportation sector plays a significant role in NO_X pollution and urge the EPA to finalize strong standards and enforcement for that sector to enable attainment of the 2015 Ozone NAAQS and achieve the benefits of that standard.

Commenter (0342) states mobile sources, and other non-EGU sectors, contribute significantly to the nonattainment issue in downwind states; these sources must be examined before seeking additional reductions from EGUs in upwind states.

Commenter (0324) says that the EPA rejects consideration of additional mobile source controls without including the necessary analysis or justification. The commenter relates that nearly 40 percent of all NO_X emissions in the country are from mobile sources, and mobile sources also emit three times more VOCs than stationary sources (7 percent of the inventory versus 2 percent). The commenter asserts that given the dominance of mobile source emissions in the NO_X inventory, and the outsized impact of these emissions on ozone, considering further controls on this sector for transport purposes is essential. The commenter notes that Step 3 of the EPA's CSAPR analysis framework requires the EPA to analyze emissions from a broad spectrum of sources to determine if they significantly contribute to downwind states, but the EPA's proposal does not include a robust assessment of mobile source emissions and only describes the existing and future federal mobile source rules that are expected to reduce emissions from that sector. The commenter adds that while other parts of the CAA provide the primary authority for regulating mobile sources emissions, nothing in the Act prohibits the additional regulation of mobile sources to address transport. The commenter asserts that the EPA needs to conduct a comprehensive evaluation to determine if additional, cost-effective federal mobile source control programs could be implemented that would further address the significant contributions of upwind states relevant to this NAAQS and include any identified available and appropriate programs in its rule.

The EPA should update national mobile source emissions standards applicable to vehicles, including medium-duty and heavy-duty trucks, which the EPA plans to finalize in 2022. Commenters add that the EPA should also require transportation control measures under the authority of the good neighbor provision to reduce interstate ozone pollution. Improved public transit, walkability, and bicycle infrastructure, see 42 U.S.C. § 7408(f), would benefit communities overburdened with mobile source emissions, as well as communities downwind.

Response:

The EPA responds to these comments in Section V.B.4 of the preamble. Comments urging the EPA to update vehicle emissions standards such as medium-duty and heavy-duty trucks are not in scope for this rulemaking.

Comment:

Commenter (0437) stated that pulp and paper mill boilers contribute less than other sources of NO_X. The commenter relates that based on the 2017 National Emissions Inventory (NEI), point sources in the 23 states emitted approximately 1.5 million tons of NO_X, whereas pulp and paper mill boilers in those states emitted approximately 35,000 tons of NO_X, or 2 percent of total point source emissions. The commenter adds that the contribution of pulp and paper mill boilers becomes even less significant considering the additional 3.3 million tons of NO_X emissions from mobile sources in the 23 states, plus the almost 1 million additional tons of NO_X from biogenic sources, wildfires, and prescribed burning. While the commenter acknowledges that the EPA has established federal programs to address NO_X emissions from mobile sources, the EPA estimates ozone season emissions reductions of 3,305 tpy of NO_X from pulp and paper mill boilers as a result of the proposed rule, which represent approximately 0.2 percent of total mobile source ozone season emissions. Thus, according to the commenter, even relatively small emissions reductions from mobile sources close to the problem monitors would likely far outweigh any ambient improvement associated with emissions reductions from pulp and paper boilers and can likely be achieved at a lower cost than the EPA's estimated $7,500/ton (2016 dollars) for non-EGUs. Commenter adds that NO_X emissions from the paper manufacturing sector have decreased by 29 percent since 2008 and data from the commenter's members show a 48 percent reduction since 2000 due to various and state regulatory programs.

Response:

The EPA responds to comments suggesting that the EPA should have included mobile source emissions reductions in this rule in Section V.B.4 of the preamble. The proportion of NO_X emissions from any single sector does not, in itself, demonstrate that the EPA should have made a different finding about the appropriateness of any given NO_X mitigation strategy for mobile sources versus stationary sources. The EPA is finalizing control requirements for boilers at Pulp, Paper, and Paperboard Mills as described in Section VI.C.5 of the preamble. Section V.D.2 of the preamble provides the EPA's basis for regulating boilers in this industry (among other non-EGU industries) as part of a set of control requirements in upwind states that, taken together, will eliminate "significant contribution" to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS.

Comment:

Commenter (0320) believes the EPA should not finalize requirements for non-EGU boilers due to the high cost of the negligible, and likely unmeasurable, impact the proposed requirements will have on receptors in downwind states. Based on the 2017 NEI, utilities contribute half of the point source NO_X emissions inventory in the 23 states in which the EPA proposes to impose non-EGU requirements at over 700,000 tpy. Mobile source emissions in the 23 states are approximately 3.3 million tpy of NO_X (50 percent of the total emissions inventory of 6.6 million tpy). NO_X emissions from the entire Mining Industry are a very small fraction of the total. The EPA should continue to focus on the largest sources of NO_X emissions.

Response:

The EPA is finalizing requirements for boilers at Metal Ore Mining facilities. The estimated control costs are discussed in Section VI.C.5 of the preamble. Section V.D.2 of the preamble discusses the impact of these emissions reductions on receptors in downwind states and provides the EPA's basis for regulating boilers in this industry (among other non-EGU industries) as part of a set of control requirements in upwind states that, taken together, will eliminate "significant contribution" to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS. *See also* Final Non-EGU Sectors TSD, Section 6.a and Section 2.2 of this document.

The EPA provides additional responses to comments regarding mobile source emissions in Section V.D.4 of the preamble.

Comment:

Commenters (0758, 0760) state that in Texas, nitrogen oxide emissions from power plants and other stationary industrial sources remain significant, but emissions from mobile sources make up nearly half of all NO_X emissions. Reducing emissions from mobile sources is key to reducing ozone pollution in many environmental justice communities across the country, including those in Texas. Commenter (0758) adds in the Dallas/Fort Worth and Houston area, mobile emissions may be even more pronounced. For the Dallas/Fort Worth area, TCEQ estimates that 77 percent of emissions of NO_X and 23 percent of emissions of VOCs are from mobile sources. For the Houston area, TCEQ estimates that 63 percent of the area's emissions of NO_X and 20 percent of the area's emissions of VOCs are from mobile sources. Commenter

(0760) goes further, adding the HGB Area was classified as being in marginal nonattainment with the 2015 Ozone NAAQS on June 4, 2018. The HGB Area is comprised of six counties: Brazoria, Chambers, Ft. Bend, Galveston, Harris, and Montgomery. On May 13, 2020, Texas submitted a SIP to the EPA containing its plan to achieve reasonable further progress, including NO_X and VOC emissions reductions of at least 9 percent to bring the HGB Area into attainment with the prior 2008 Ozone NAAQS, as the HGB Area was still in nonattainment of the 2008 NAAQS as well. All of the HGB Area proposed emissions reductions submitted to show reasonable further progress was based on control measures for mobile sources and non-road engines. The contingency measures proposed by Texas also consisted of NO_X reductions from mobile source control measures. The focus of the HGB Area on the reduction of mobile source and non-road source emissions makes sense. 63 percent of the area's NO_X emissions are from on-road mobile sources and 32 percent from non-road mobile sources. Thus, Texas, with the EPA approval, rightfully believes that their efforts to achieve attainment should be focused on control of these emissions.

Response:

The EPA responds to comments regarding controlling mobile sources in Section V.B.4 of the preamble. Aspects of this comment related to Texas' efforts to achieve attainment of the 2015 ozone NAAQS, insofar as it pertains to ozone nonattainment area planning requirements, are not in scope for this rulemaking.

Comment:

Commenters (0279, 0541) argue the highest NO_X emissions in Alabama come from the mobile sector, not the point source sector, it is expected that ozone would be created and remain locally. Further, statewide NO_X emissions from point sources continue to decline, as shown by the precipitous drop in tonnage in the commenter's major source emissions inventory. Mobile source emissions will continue to decrease nationwide due to turnover in the gasoline and diesel fleets and due to the rise in use of electric vehicles. The TSD states that the threshold alone does not determine whether a state significantly contributes to a nonattainment or maintenance monitor from a downwind state. After identifying potential state-wide significant contributors, the third step is to identify which sources contribute to downwind nonattainment/maintenance. Since the biggest sources of NO_X in Alabama are from mobile sources, controls on those sources should be evaluated first.

Response:

The EPA's modeling demonstrates interstate transport of ozone precursors from sources in Alabama contribute above the Step 2 threshold to one or more receptors as discussed in Section IV of the preamble.

The EPA agrees with the statement noted by the commenter that the threshold alone does not determine whether a state significantly contributes to nonattainment or maintenance in other areas. The determination that a state is linked at Step 2 moves that state for further analysis at Step 3. Then the EPA applies the multi-factor test at Step 3 to determine whether significant contribution exists.

The EPA does not agree that controls from mobile sources must be evaluated first due to the proportion of emissions coming from mobile sources. This rule continues the Agency's longstanding focus on large stationary sources of NO_X as the most cost-effective method of addressing interstate transport obligations under CAA section 110(a)(2)(D)(i)(I).

Comment:

Commenter (0539) articulates that in the state of Minnesota, power plants (of any fuel type) are now only responsible for about 7 percent of in-state anthropogenic NO_X emissions. This is less than the national value of about 10 percent of total NO_X emissions from the power sector in 2021. By contrast, highway vehicles and mobile sources are now by far the largest source of NO_X emissions in Minnesota as of 2021 at 23 percent and 31 percent, respectively, totaling ~53 percent after rounding. By only seeking to further ratchet down emissions from stationary EGUs that have already reduced their own NO_X emissions by almost 90 percent, this proposed FIP effectively punishes stationary EGUs such as commenter (0539)'s for their proactive efforts while concurrently ignoring the most impactful anthropogenic sources of NO_X emissions, both in Minnesota and nationwide. While the EPA is proposing to regulate stationary non-EGU sources under the proposed FIP (about 38 percent of Minnesota NO_X emissions), mobile sources are still a larger contributor of NO_X than are stationary sources as a whole.

Response:

The EPA does not agree with the commenter's assertion that the final rule "effectively punishes stationary EGUs…while concurrently ignoring the most impactful anthropogenic sources of NO_X emissions." For further discussion, see Section V.B of the preamble.

Comment:

Commenter (0281) states in California, NO_X emissions are dominated by mobile sources which are a primary focus of many of California's rules and regulations. The proposed FIP concludes that there are "no additional emissions reductions required to eliminate significant contribution from any EGU sources in California" and therefore only emissions limitations for non-EGU sources are included for California. The total NO_X emissions reductions from non-EGU industrial sources in California is estimated to be 1,666 tpy in 2026 relative to 2019, which represents only one and a half percent of the total NO_X emissions reductions from control strategies by the California Air Resources Board (CARB) and California air districts between 2019 and 2026. By themselves, CARB believes that the proposed FIP measures are neither efficient nor effective in reducing NO_X emissions in California and mitigating interstate transport impacts.

CARB believes that stringent programs are already far exceeding the NO_X reductions that the FIP seeks to mitigate.

Response:

The EPA has concluded that no additional emissions reductions are required to eliminate significant contribution from EGU sources in California for purposes of the 2015 ozone NAAQS.

The EPA's analysis indicates that California is significantly contributing to nonattainment or interference with maintenance of the NAAQS in other states. The proportion of the estimated tons reduced as a result of this rule, relative to NO_X emissions reductions generated from other control strategies implemented by CARB, does not impact the EPA's Step 3 determination that cost-effective emissions reductions are available from non-EGU sources within California. The EPA does not agree that the FIP requirements finalized in this rule are inefficient and ineffective at reducing home state ozone concentrations within California or the impacts of ozone interstate transport to other states.

Comment:

Commenter (0281) continues, driven by nonattainment challenges, California's emissions reduction control stringency leads the nation for most sectors of emissions sources. California's programs have paved the way for a number of federal programs that have since been implemented nationwide. This added level of control applicable to California emissions sources was implemented to expedite attainment of air quality standards within California. CARB believes that these stringent programs are already far exceeding the NO_X reductions that the FIP seeks to help mitigate transport impacts. Federally regulated mobile sources are a Significant contributor to NO_X emissions in California and are actively contributing to nonattainment of federal standards. Statewide NO_X emissions in 2020 from federal sources exceeded emissions from California-regulated mobile sources. Without federal action, by 2030 NO_X emissions from these sources will be double California-regulated mobile sources. Therefore, it is imperative that the federal government act decisively to reduce emissions from sources of air pollution under its control that operate in California.

Response:

The EPA appreciates CARB's control programs to reduce emissions and attain air quality standards within California. Comments regarding mobile sources are addressed in Section V.B.4 of the preamble.

Comment:

Commenters (0323, 0409) asserts that even the EPA recognized that mobile and other local sources are the likely cause of high ozone in Connecticut. In a May 14, 2018, presentation titled "Analysis of Ozone Trends in the East in Relation to Interstate Transport", Norm Possiel of the EPA Office of Air Quality Planning and Standards linked high ozone in coastal Connecticut to mobile source emissions in the New York City area and peaking units within the OTR among other local sources in the Connecticut area. More recently, in a November 9, 2021, presentation to the OTC, Dr. Jeff Underhill, Chair of the OTC Modeling Committee, showed the hourly source apportionment results that demonstrate onroad and nonroad emissions dominate ozone formation in the modeled simulation at the Connecticut monitor. Commenter (0323) continues, an example of the relative contribution of EGU and non-EGU point source emissions to the downwind receptor (90099002) at New Haven, Connecticut shows a small contribution of both EGU and non-EGU point source emissions (6 percent) toward the total contribution of emissions forming ozone in the 2023 modeled simulation in comparison with the 47 percent contribution of mobile sources. A similar level of emissions from EGU and non-EGU NO_X contribution is seen at the Kenosha, Wisconsin nonattainment monitor (550590019), where almost 43 percent of NO_X contributions is from mobile and area source sectors.

Commenter (0359) cites the Connecticut Department of Energy and Environmental Protection providing comment to the Advanced Notice of Proposed Rulemaking for the Control of Air Pollution from New Motor Vehicles: Heavy Duty Engine Standards on February 19, 2020, acknowledged the magnitude of the vehicular contribution by stating: "Connecticut air quality monitors record some of the highest ozone levels in the eastern United States, especially along heavily trafficked transportation corridors where criteria air pollutant emissions are most densely concentrated. In 2019 Connecticut monitored twenty-one days when air quality in the state exceeded the 2015 ozone NAAQS. Mobile sources account for sixty-seven percent of NO_X emissions in Connecticut."

Commenter (0324) notes that the EPA's recent mobile source rules will not result in any measurable emissions reductions by attainment dates for the 2015 NAAQS. The commenter adds that the EPA's recent proposed disapprovals of state transport SIPs for the 2015 NAAQS concluded that simply identifying existing programs to satisfy transport obligations, as the EPA does here, was inadequate. The commenter relates that in its proposed disapproval of Wisconsin's transport SIP submission, the EPA stated that "the listing of existing or on-the-way control measures…does not substitute for a complete Step 3 analysis under the EPA's 4-step interstate transport framework to define 'significant contribution,' " and the EPA goes on to describe in detail what must be assessed before an emissions sector can be removed from transport consideration. The commenter contends that the EPA's evaluation of potential mobile source controls should include those analytic elements.

Commenter (0758) states the EPA should consider reductions from mobile sources and indirect sources. The commenter suggests approaches of requiring intermodal freight facilities and charging indirect sources that are federally assisted a mitigation fee and apply the resulting funds to nearby sources of NO_X.

Response:

The EPA provides a response to comments suggesting the final rule should require mobile source emissions reductions in Section V.B.4 of the preamble.

Comments:

Commenter ID No. for the following comments is 0323 (pg 2-7).

Another key source of impact upon nonattainment are mobile sources. Within the CAA, Subchapter 1, part D titled "Plan Requirements for Nonattainment Areas" is found subpart 1 titled "Nonattainment Areas in General." Subpart 1 includes CAA section 177 addressing new motor vehicle emissions standards in state plans for nonattainment areas. It is apparent that the CAA contemplated the option of developing nonattainment plans per CAA section 172 to address certain new motor vehicles or new motor vehicle emissions. For those approved downwind nonattainment plans that include motor vehicle emissions reduction strategies for achieving attainment, delay in implementation beyond the attainment date is unacceptable under CAA §179. In the proposed FIP, EPA provides,

> The EPA recognizes that mechanisms exist under title I of the CAA that allow for the regulation of the use and operation of mobile sources to reduce ozone-precursor emissions. These include motor vehicle inspection and maintenance (I/M) programs, gasoline vapor recovery, clean-fuel vehicle programs, transportation control programs, and vehicle miles traveled programs. *See, e.g.*, CAA sections 182(b)(3), 182(b)(4), 182(c)(3), 182(c)(4), 182(c)(5), 182(d)(1), 182I(3), and 182(e)(4). The EPA views these programs as most effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.
>
> 87 Fed. Reg. 20,077, f/n 142.

EPA acknowledges the significance of mobile source emissions to nonattainment. Delay in implementation of needed attainment mobile source controls by a downwind state unlawfully shifts the emissions reduction burdens onto upwind states if EPA fails to engage in alignment of the dates upon which each of the states must satisfy nonattainment strategy performance

Commenter (0286) states that the EPA ignores the largest contributor to nonattainment. Review of available data on source apportionment shows that the most significant contributor of ozone nonattainment is mobile sources. By failing to address these sources or align programs to address these sources in this proposal, the commenter believes that the EPA will have nominal impact on air quality at a great cost to ratepayers and risk to reliability. The commenter asserts that continuing to attempt to seek nearly all air quality improvements from a declining number of EGU sources will not have the intended impact on downwind ozone concentrations and will have unintended negative societal consequences.

Commenter (0383) EPA has not demonstrated the proposed FIP will contribute to meaningful reductions of ozone concentration in neighboring states. Nevada's largest contribution to downwind nonattainment receptors would be in 2023 —0.89 ppb (1.27 percent of the standard) and in 2026— 0.81 ppb (1.16 percent of the standard). Additionally, Nevada's largest contribution to downwind maintenance-only receptors would be in 2023 — 0.58 ppb (0.83 percent of the standard) and in 2026 — 0.51 ppb (0.73 percent of the standard). The proposed FIP assumes that Nevada's participation in the Cross-State Air Pollution Rule and establishing NO_X emissions limitations applicable to certain other industrial stationary sources will address Nevada's interstate transport requirements but does not demonstrate that these actions will contribute to meaningful reductions of ozone concentrations in neighboring states. The proposed FIP fails to consider and address that in Nevada, sources regulated by the EPA emit the plurality of NO_X, specifically from the mobile source sector. Nevada has done significant work in the mobile source section, including adopting a zero-emissions vehicle (ZEV) requirement for model year 2025. While EPA has mobile source emissions standards, there currently is no federal ZEV requirement. The proposed FIP would allow states to submit an SIP revision for EPA approval to achieve the emissions reductions needed to meet the state's new interstate transport obligations included in the new rule. However, the proposed FIP significantly limits flexibility for states to address NO_X emissions from sources other than those EGUs and Non-EGUs already identified in the FIP and does not consider other significant sources of NO_X common in the west.

Commenter (0436) states that a significant portion of states' total contribution to downwind areas include emissions that states have limited regulatory authority and, in some cases, no regulatory authority at all, including emissions that are federally regulated. This includes the mobile sector which accounts for more than half of Utah's statewide precursor emissions. Thus, the majority of the emissions used to quantify Utah's contribution to downwind states are not under Utah's regulatory authority.

Commenters (0295, 0315, 0300, 0324, 0383) state the proposed FIP fails to consider the dominance of mobile source emissions in the NO_X inventory, and its impact on ozone. They advocate equal resource allocation and analysis of existing and future mobile source emissions reduction programs. Commenter (0315) advocates applying 0.70 ppb threshold only to anthropogenic sources that are contributing or potentially controllable under the proposed rule.

Commenter (0428) states that in the WESTAR region, sources regulated by the EPA emit the plurality of the regional NO_X, specifically from the mobile source and goods movement sectors. NO_X emissions from these sectors will comprise 44.5 percent of the projected western inventory by 2028. By that time, State Implementation Plans (SIPs) from WESTAR region states will complete federally enforceable implementation of stationary source NO_X controls and/or require reduced NO_X emissions under the Regional Haze Rule, beyond the current "rules on the books" scenario developed in 2020. Further planning to continue reductions of stationary source NO_X emissions will be ongoing with the upcoming 2028 Regional Haze SIP milestone, a major work effort for WESTAR region states.

Commenter (0324) states that the proposed rule is inadequate to meet the transport requirements for the 2015 ozone NAAQS, asserting that mobile sources should be included in Step 3 of EPA's analysis, not merely stationary sources including EGUs and certain [non-EGU] industries. Commenter's rationale includes the assertion that mobile sources comprise a significant part of the emissions inventory and remain a major source of ozone causing pollutants. According to the 2017 National Emissions Inventory, nearly 40 percent of all NO_X emissions in the country are from mobile sources. In contrast, stationary sources – the sole focus of this rule – represent only 23 percent of the inventory. The commenter provides similar statistics for mobile sources and stationary sources based on modeling done by LADCO in Wisconsin. This commenter contends that Step 3 of the CASPR analysis framework requires EPA to analyze emissions from a broad spectrum of sources to determine if they significantly contribute to downwind states. The commenter reiterates EPA's own guidance regarding Wisconsin's transport SIP not providing for a complete Step 3 analysis under EPA's 4-step interstate transport framework, and asserts that the EPA's evaluation of potential mobile source controls should include these analytic elements as well, noting that nothing in the CAA prohibits the additional regulation of mobile sources to address transport. Commenter (0324) concludes that "EPA needs to conduct a comprehensive evaluation to determine if additional, cost-effective federal mobile source control programs could be implemented that would further address the significant contributions of upwind states relevant to this NAAQS."

Response:

The EPA provides a response to comments suggesting the final rule should require mobile source emissions reductions in Section V.B.4 of the preamble.

Comment:

Commenters (0758) state the EPA's previous ozone transport rules have overlooked another large source of nitrogen oxides: freight facilities, including marine ports and railyards. The nitrogen oxide emissions associated with these facilities are on par with those from coal-fired power plants. The commenters believe the importance of these facilities is typically obscured by the way emissions inventories are organized, because their emissions are lumped in with all other mobile source emissions. But this approach ignores that mobile source operations and their emissions are concentrated at these facilities, which are often located in disadvantaged communities, and ignores the many ways that the design and operation of these stationary facilities can affect the related nitrogen oxide emissions. The commenters note the CAA recognizes that these mobile source "magnets," or indirect sources, are potential targets for regulation, but limits the EPA's authority to adopt national indirect source review rules. See 42 U.S.C. § 7410(a)(5)(A)(ii). The ozone transport rule, however, provides an important opportunity for the EPA to address these sources.

Commenters (0758) believe regulation of these sources has the potential to provide significant reductions in nitrogen oxides and transported ozone pollution. There are a variety of ways that an indirect source review rule could be designed to control the way facilities are operated or built to reduce nitrogen oxide emissions, even while boosting efficiency. Commenters provide the example, strategies, such as intelligent dispatch systems or simple prohibitions, can minimize idling of vessels, trucks, and equipment. Strategies that require investment in infrastructure to support the use of zero emissions technologies can eliminate mobile source emissions both at the facility and beyond. The South Coast Air Quality Management District recently adopted an indirect source review rule to address emissions associated with warehouse operations. Including indirect source measures in ozone transport rules can provide nitrogen oxide emissions benefits and serve as a model for states interested in addressing these indirect sources themselves.

Response:

The EPA acknowledges that there are many other anthropogenic sources of NOX emissions in upwind states than are covered in this final rule. The Agency implemented a reasonable methodology to focus on the most impactful NOX emissions-reduction opportunities in industries beyond the power sector. The Agency has explained how this evaluation is consistent with the 4-step interstate transport framework and has allowed for the identification of a set of emissions reductions in upwind states that, taken together, eliminate "significant contribution" to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS. Comments calling for the regulation of other sources of NOx emissions generally lack reasonably specific evidence that would justify targeting these sources of emissions reductions rather than the emissions sources covered in this rule. We note that states have the opportunity to replace this FIP with a SIP targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP, as discussed further in Section VI.D of the preamble.

Comment:

Commenter (0764) states mobile sources (onroad, nonroad, and rail) account for 49,531 tpy (more than 51 percent) of the 96,500 tpy modeled for the entire state of Arkansas. Non-EGU point sources account for 11,565 tpy (12 percent). The total Tier 2 emissions would be a small fraction of this amount. Even relatively small emissions reductions from mobile sources close to the problem monitors would likely far outweigh any ambient improvement associated with emissions reductions from boilers and can likely be achieved at a lower cost than the EPA's estimated $7,500/ton (2016 dollars) for non-EGUs.

Commenter (0331) states the relatively small contribution of EGU (4 percent) and non-EGU (9 percent) point source emissions at the Chicago-Alsip, Illinois maintenance monitor (170310001) where over 37 percent of NO_X emissions contribution to modeled ozone is from mobile and area source sectors and less than 50 percent of the total ozone formed is from domestic anthropogenic emissions. Assessment of the relative contribution indicates that motor vehicle emissions are a considerable fraction of relative contribution to 2023 ozone concentration predictions in the Lake Michigan area.

Response:

The proportion of NO_X emissions from any single sector does not, in itself, demonstrate that the EPA should have made a different finding about the appropriateness of any given NO_X mitigation strategy for mobile sources versus stationary sources. The EPA provides a response to comments suggesting the final rule should require mobile source emissions reductions in Section V.B.4 of the preamble.

Comment:

Commenter (0331) cite comments filed by states and agencies, including Minnesota and LADCO, support the need for additional mobile source controls to improve air quality and to achieve attainment. Specifically, the MPCA commented that:

- Minnesota needs NO_X reductions from heavy-duty vehicles to reduce ozone formation, address disparities in air pollution exposure, and improve overall air quality and related health outcomes. Future NO_X reductions from heavy-duty trucks will help Minnesota reach its Regional Haze targets and reduce ozone transport.
- Minnesota has sought and achieved significant NO_X reductions at industrial and electric generation sources but needs federal leadership to achieve on-road transportation reductions. The MPCA looks to the EPA to develop appropriately protective policies for heavy duty vehicle-related pollution.

The commenter cites the Lake Michigan Air Directors Consortium, who state their "modeling results show that relative to other source types, emissions from roadway mobile sources are the largest contributors to surface ozone in the Great Lakes region. Regulatory actions that result in emissions reductions from roadway mobile sources will impact a major source of ozone precursor emissions in this region."

Response:

The proportion of NO_X emissions from any single sector does not, in itself, demonstrate that the EPA should have made a different finding about the appropriateness of any given NO_X mitigation strategy for mobile sources versus stationary sources. The EPA provides a response to comments suggesting the final rule should require mobile source emissions reductions in Section V.B.4 of the preamble.

The comment discussing the impacts of mobile source reductions, specifically from heavy duty trucks, on achieving regional haze targets is not in scope for this rulemaking.

Comment:

Commenter (0359) notes should all upwind stationary sources of NO_X cease to operate, instruments adjacent to and generally downwind of major interstate highway arteries, including Interstate 95, will continue to report much higher than background levels of ground-level ozone, with many in nonattainment. It would be considerably more prudent for the EPA to encourage downwind states with nonattainment and maintenance areas to implement tighter emissions limits or increased tolling for mobile sources located within their respective jurisdictions.

The commenter points out this condition is only exasperated by the recent discovery of the tampering of diesel engines where various air pollution control and emissions reduction measures have been disabled, removed, or otherwise eliminated. Because of this tampering, emissions of diesel engine NO_X are expected to be many orders of magnitude greater than previously believed. The commenter adds with the COVID-19 pandemic, this condition has only worsened with the increased number of diesel trucks on the roads to supply the population with needed goods. Additionally, with less traffic on the interstate systems, diesel trucks have avoided the metropolitan area bypasses opting for more direct cost saving routes, bringing NO_X emissions closer to the various air monitoring stations and having a greater impact on those stations' ability to demonstrate attainment. During this same period, electricity demand from manufacturing and business operations has been reduced as well as the normal NO_X emissions from those generating facilities. However, these stations are still recording exceedances. The commenter concludes, therefore, their inability to meet attainment must be the result of local emissions sources and not upwind sources.

Response:

Comments regarding tampering of pollution control devices on diesel engines and increased tolling requirements for mobile sources are not in scope for this rulemaking.

The EPA included NO_X emissions from diesel trucks in the emissions inventories for onroad mobile sources. The commenter does not provide sufficient evidence for the EPA to analyze the claim that increased diesel trucks on the road increased NO_X emissions as a result of the COVID-19 pandemic.

Comment:

Commenter (0303) states any rule affecting California needs to consider the largest NO_X

sources in CA that impact attainment inside CA, and then evaluate how these sources will impact attainment in downwind states, for example, mobile sources.

Response:

The proportion of NO_X emissions from any single sector does not, in itself, demonstrate that the EPA should have made a different finding about the appropriateness of any given NO_X mitigation strategy for mobile sources versus stationary sources. The EPA provides a response to comments suggesting the final rule should require mobile source emissions reductions in Section V.B.4 of the preamble.

Comment:

Commenter (0835) adds heavy duty vehicle emissions, including from school buses and public buses, increase air pollution and contribute to climate change. Because of discriminatory transportation decisions that have placed major roads and highways through the commenter's communities, black neighborhoods face significantly higher exposure to air pollution from vehicle pollution compared to whites. And it is well documented that climate change hurts communities of color first and worst.

Response:

Emissions from heavy duty vehicles were included in the emissions inventories for onroad mobile sources, as described in Section IV.C.4 of the preamble. The EPA's analysis of environmental justice impacts of this rule is in Section VII of the preamble.

The comment regarding the impacts of climate change on communities of color is not in scope for this rulemaking.

4.3 Control Stringencies by Cost Threshold and Corresponding Emissions Reductions

4.3.1 General Comments

Comment:

Commenter (0506) supports the EPA's cost estimates.

Response:

Thank you for your comment.

Comments:

The commenter (0362) also mentions that when inflation is accounted for, the EPA's cost effectiveness threshold of $7,500, which was expressed in 2016 dollars, equates to in excess of $9,000 in 2022 dollars when adjusted for the construction cost index that reflects the impacts of inflation on the buying power of the dollar.

Commenter (0760) states that the EPA is using outdated cost figures to calculate the cost of retrofit with LNB or ultra-low NOx burner (ULNB) controls, and the EPA must also readjust its projected cost factors to 2022 dollars using inflation factors that are consistent with the current high inflation rates. The commenter states that the EPA should carefully consider whether the proposed FIP may unnecessarily increase costs and contribute to further inflation.

Commenter (0547) says that the costs used in the EGU NO_X Mitigation Strategies Proposed Rule TSD are in 2016 dollars. With inflation, the EPA's costs are low. Based on the U.S Bureau of Labor Statistics' Consumer Price Index (CPI) Inflation Calculator, the weighted average cost for SCR which was estimated at $11,000/ton estimate (for coal units of 100 MW or greater capacity that do not have post-combustion NO_X controls) is now over $13,000 in 2022 dollars.

Commenter (0546) states that in preparing revised cost estimates to support a final FIP, the EPA should ensure that recent and significant inflation trends are incorporated into its analysis. The commenter notes that the latest (May 2022) consumer price index reported by the US Bureau of Labor Statistics has increased by 8.6 percent over May 2021, which is the largest 12-month increase in over 40 years. The commenter contends EPA should account for current and anticipated future economic conditions, including inflation, in any cost analyses which inform the final FIP.

Response:

The EPA consistently uses $2016 dollars throughout this rule, including both for costs and benefits, and this is a standard analytical choice. As the commenter shows, it is straightforward for interested stakeholders to adjust the costs and benefits from $2016 dollars. Furthermore, to the extent that mitigation costs may have changed in excess of general inflation (or vice versa) we performed a sensitivity analysis on costs in the EGU NO_X Mitigation Strategies Final Rule TSD. We address potential supply-chain issues in Section 10 of this document. The economic effects of this rule are described in the RIA.

4.3.2 Cost Threshold Limit

Comments:

Commenter (0519) states while courts have upheld the EPA's reliance on a uniform cost threshold as a proxy for eliminating significant contributions, the EPA has never attempted to apply this approach across parallel programs that will simultaneously work to eliminate significant contributions in different industry sectors. Rather than considering the combined effects of emissions reduction measures under the EPA's chosen cost thresholds, the EPA simply requires all "available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels," based on its assessment that "these emissions reductions will make a meaningful improvement in air quality. "The EPA's failure to adequately analyze the combined emissions reductions impacts from EGUs and non-EGUs creates an unreasonable risk that Oklahoma will be subject to overcontrol. The EPA's EGU/ Non-EGU Contribution Spreadsheet indicates that, in 2026, EGUs in Oklahoma will contribute under 0.05 ppb to downwind air quality problems at each receptor to which Oklahoma remains linked. Specifically, EGUs will contribute 0.04 ppb to Receptor 170310032 in Cook County, Illinois and 0.03 ppb to Receptor 481210034 in Denton County, Texas. Oklahoma's total anthropogenic NO_X emissions in the 2026 ozone season are projected to be 83,411 tons, with EGU s contributing 2,407 tons. Of these 2,407 tons, only a small fraction needs to be eliminated to secure attainment at both linked receptors, meaning that emissions reductions of only a few additional tons may create significant overcontrol. This already-significant risk is worsened by the EPA's failure to consider the combined emissions reductions from EGUs and non-EGUs in the state.

Commenter (0758) states A cost threshold of $11,000/ton NO_X that represents installing SCR on large coal-fired EGUs would comport with the EPA's traditional approach to identifying the pollution control techniques that determine emissions budgets for the EGUs in covered states. The EPA's cost analysis for SCR technology is conservative and likely overestimates the cost of controls in at least two ways.

> First, EPA's cost recovery factor is higher than warranted, and therefore overestimates costs to generators. Specifically, in its cost estimates for retrofitting EGUs with SCR, EPA assumed a capital recovery factor of 0.143. If EPA assumed a 15-year life of SCR to arrive at a capital recovery factor of 0.143, that means it assumed an interest rate of 11.5 percent. Moreover, EPA's assumed interest rate used for determining annualized capital costs of control is much higher than the current bank prime interest rate which EPA typically recommends for use in cost effectiveness analyses unless a firm-specific interest rate can be justified. The current bank prime lending rate is 4.75 percent, which is significantly lower than the interest rate that the EPA apparently has assumed in the cost effectiveness analysis for the Good Neighbor Plan. EPA's real cost of capital also appears high. For example, EPA's real cost of capital is significantly higher than the weighted cost of capital approved by public utility commissions for PacifiCorp, which owns several EGUs affected by the Good Neighbor Plan. PacifiCorp has stated that its weighted average approved cost of capital is 7.303 percent.
>
> Second, EPA's assumption that an SCR at a coal-fired EGU would only have a life of only fifteen years is not justified, and makes SCR appear more expensive than it is. The EPA's Control Cost Manual, last updated in 2019, discusses this issue at length, explaining, "the equipment lifetime of an SCR system is assumed to be 30 years for power plants" and that "these assumptions are based on several sources including . . . an expert report in the North Carolina lawsuit against the TVA coal-fired electrical generation units indicated an expected useful life of an SCR is 30 years.; 2002 study of economic risks from SCR operation at the Detroit Edison Monroe power plant used 30 years as the anticipated lifetime; and a design lifetime of 40 years was used for an SCR at the San Juan Generating Station."

Furthermore, commenter (0758) notes the EPA must establish higher cost thresholds for EGUs in light of downwind states' control requirements and persistent ozone transport problems in those states. A higher cost threshold would be feasible and cost-reasonable, as evidenced by successful emission-reduction programs in downwind states. In the Revised CSAPR Update, several downwind states cited their own requirements for EGU NO_X controls that were estimated to achieve emissions reductions at much higher costs-per-ton. For example, under

Connecticut's regulations, an emissions limitation in a case-by-case RACT determination for any emissions unit (including a boiler serving an EGU, or a combined cycle combustion turbine) is presumptively feasible so long as it has a cost-effectiveness value equal to or less than \$13,118/ton NO_X. A New Jersey rule deems "technically feasible" SCR retrofits on natural gas compressor turbines (*i.e.,* simple-cycle turbines) at costs up to \$18,983/ton NO_X. This coalition of downwind states argued that these requirements secured significant emissions reductions from their existing sources, and that establishing budgets for upwind states under the Revised CSAPR Update reflecting a much lower cost threshold would be inequitable. The EPA responded with the following points:

- Downwind states' emissions reductions were more effective at addressing air pollution problems within those states than were reductions in upwind states.
- The post-combustion controls represented by higher cost thresholds could not achieve emissions reductions until 2025, when all downwind nonattainment and maintenance issues with the 2008 ozone NAAQS would have been resolved.
- The "knee in the curve" plotting emissions reductions and air quality improvements against the cost-effectiveness values of various controls that appears at the cost threshold associated with optimizing existing controls and installing combustion controls is a "reasonable stopping level."

These responses were not persuasive when the EPA promulgated the Revised CSAPR Update, and they certainly would not justify ruling out higher cost thresholds for EGUs in this rule, for the following reasons:

- The advantages of achieving greater improvements in air quality from geographically nearer reductions could also support gradations of cost thresholds within the EGU trading program for upwind states, with elevated cost thresholds applying to states closer to downwind receptors, yet EPA has historically applied the same cost threshold to upwind states' EGUs regardless of distances from downwind states, to reach an equitable result.
- EPA has concluded that downwind receptors continue to have difficulty attaining and maintaining the 2015 ozone NAAQS in 2026 following imposition of the proposed rule's requirements, when additional post-combustion controls could be installed regionwide.

As noted above, the EPA has stated that a knee in the curve plotting emissions reductions and air quality improvements against the cost-effectiveness values of various controls is not an independent basis for ruling out controls at a higher cost threshold, provided that those controls achieve significant emissions reductions and air-quality improvements.

Response:

Comments suggesting the EPA is not considering EGU and non-EGU reductions collectively are not correct. See preamble Section V.D.3 "Combined EGU and non-EGU analysis" along with the Ozone Transport Policy Analysis Final Rule TSD for a detailed description of the overcontrol analysis.

The EGU NO_X Mitigation Strategies Final Rule TSD includes an evaluation of multiple sensitivities where the parameters central to cost effectiveness are examined at different levels. In all cases, the EPA finds its identified control stringency levels appropriate for this final rule.

4.3.3 Quantification of Cost-Effective Controls

Comments:

Commenter (0517) states that the proposed disapproval excludes quantification of cost-effective controls making it deficient. The EPA makes no effort to quantify the cost-effective NO_X emissions reductions that will yield sufficient downwind air quality benefits. This sets an inappropriate burden on Oklahoma to look into the future, anticipate the EPA's rulemaking, and incorporate those anticipated findings in a SIP submission. The EPA should not dismiss outright that control measures equivalent in cost to previous iterations of the ozone NAAQS could be sufficiently protective for downwind states.

Commenter (0398) maintains that the EPA fails to consider remaining useful life for facilities which will operate only a handful of years beyond 2026. Cost-effectiveness for control installation on those facilities operating less than 15 years beyond 2026 would only further exceed the already, extraordinarily high figures which the EPA calls cost-effective in the proposed FIP. Additionally, the proposed FIP and underlying data analysis assumes that EGUs with commitments to cease coal combustion in the near future will install costly post-combustion NO_X controls in 2026, only to operate with those new NO_X controls for three to five more years. In stakeholder outreach, the commenter heard concern from regional energy managers in several regions that the proposed FIP does not contemplate a step for the RTO to study reliability impacts, and that the addition of a reliability exception or "safety valve" must be considered by the EPA in the framework to allow Resource Adequacy-based decisions to protect reliability nationwide. The EPA did not (and likely cannot, from both technical and legal perspectives) adequately demonstrate that the fleet-wide proposed controls for EGUs will be balanced with the nation's requirements for energy generation.

Response:

Comments regarding SIP disapproval(s) are out of scope for this action.

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). Nevertheless, the EPA does examine the appropriateness of its control stringency levels under different book life assumptions and discusses such findings in preamble Section V.B.1.e and the EGU NO_X Mitigation Strategies Final Rule TSD. Section VI.B.2 of the preamble addresses concerns regarding reliability and how the EPA's final rule addresses all such concerns.

4.3.4 SCR Installation / Retrofit Costs

Comments:

Commenter (0531) states a recent indicative cost estimate reports that a single SCR could cost as much as $290M, and multiple SCR's as much as $250M each.

Commenter (0531) states the SCR retrofit installation costs as presented by the EPA do not consider site specific challenges associated with the complex and congested footprint at most energy center facilities. The commenter evidence:

- The current economic conditions and inflation rate have resulted higher costs for virtually every manufactured product and making it extremely difficult to predict future costs.
- Availability of craft labor for large projects such an SCR retrofit is very uncertain. Additional overtime and perhaps even per-diem costs may be required to secure the labor needed for these projects thereby driving up construction cost.
- With no current operating margin, existing induced draft (ID) fans will need to be replaced with new larger fans to overcome the additional pressure drop resulting from the SCR catalyst and additional ductwork. The fans will require new motors with higher electrical power requirements. The existing ductwork and draft components will likely require structural reinforcement to accommodate the new lower operating pressure from new ID fans.
- With no existing site access to anhydrous ammonia, all reagents will need to be transported to the Plant site by truck or rail, and the required quantities for these units will require a very large facility which will have to be located far from the SCRs.
- The relocation of numerous underground utilities.
- To address the congested site, preliminary studies of SCR retrofits have necessitated the removal of numerous existing plant structures as well as "surgical" installation of required SCR support structures. It will also require the use of exceptionally large cranes, which will likely be in short supply when needed.
- A retrofit project as contemplated by the EPA will require structural reinforcement of existing structural steel to meet all current wind and seismic codes.
- To be more responsive to load cycling from increased renewable generation, the cost of an economizer hot water recirculation system or similar is necessary to control the economizer gas outlet temperature for a new SCR retrofit.

Response:

The EPA addresses the representativeness and reasonability of its cost assumptions in both Section V of the preamble and in the EGU NO_X Mitigation Strategies Final Rule TSD. In those locations, the EPA provides extensive technical evaluation supporting its assumptions – including material provided by 3rd party engineering and pollution control groups. Moreover, the EPA further analyzed its cost assumptions by performing a variety of sensitivity analyses looking at different assumptions such as book life, coal rank, and input cost. It did not find any evidence that it should reverse its mitigation and stringency assumptions nor abandon its use of a trading program. The commenter misconstrues representative fleet assumptions as unit-level requirements – they are not. The EPA notes in the preamble that there will be outlier sources with cost, performance, and timing that deviate from the average or representative values used in its cost assumptions (as is inherent in the use of averages). The EPA's use of a trading program accommodates this cost heterogeneity and provides lower cost alternatives for sources to comply.

The above comments - some of which suggest alternative assumptions indicating a higher cost and some indicating alternative assumptions that would lead to lower cost – illustrate that a representative value is appropriate and that there will be unit-level variation from that average in both directions. In regard to any references to the EPA's Revised CSAPR Update analysis, the EPA further notes that post-combustion control retrofit was not included in the mitigation strategies for reasons unrelated to cost (it was not possible to install during the limited time period for which a nonattainment and upwind linkage were expected to persist).

The EPA addresses overcontrol concerns in Section V.D.4 of the preamble and in Appendix D of the Ozone Transport Policy Analysis Final rule TSD. The EPA found no over control in the final rule.

4.3.5 EGUs

Comment:

Commenter (0387) writes that the EPA should take an incremental approach to NO_X controls for EGUs and reduce the extent of premature retirements related to the proposed rule.

Response:

The state budgets in this final rule do not mandate any retirements. The EPA further notes that its Step 3 analysis is conducted in an incremental manner where each tier of mitigation measures (and corresponding cost threshold) is examined incrementally to arrive at the determination of control stringency that constitutes the removal of significant contribution (see preamble Section V).

4.3.5.1 Approach / Assumptions Used to Develop Costs

Comments:

Commenters (0290, 0547) comment on the approach and assumptions the EPA used to develop the costs of the SCR option. The commenters state that the IPM model does not produce site-specific cost estimates that could significantly increase costs and provided examples of its own facility where site-specific costs that can balloon the cost higher than a general algorithm. To illustrate, commenter (0290) notes that in regard to a boiler SCR retrofit, typically, units are congested at the economizer outlet, where SCRs are generally located; adding that ductwork routing can be complicated to get out of the boiler building. In addition, the commenter notes that SCRs are located a couple hundred feet in the air which could impact where columns to support the structure could be located at grade.

Commenter (0300) is very concerned with the proposed FIP's disconnect between energy supply, environmental compliance, and economic development in Kentucky, and disagree with assumptions made that the proposed rule would result in "substantial and meaningful improvements in air quality," despite the EPA's analysis showing air quality improvements from the four categories of control (*e.g.,* existing EGU controls in 2023 and new EGU control/Generation shifting in 2026). Commenter questions the EPA approach that continues penalizing point sources like the power sector while failing to address mobile source (transportation sector) contributions despite the fact that it has been established that mobile sources are the primary contribution to the remaining air quality problems.

Commenter (0544) states the EPA's cost assumptions are inconsistent with current market conditions and flawed for several reasons. Foremost, the assumed cost of compliance to optimize an existing SCR is underestimated – the current cost of a 50 percent weight solution of urea—required for SCR operation at the commenter's facility, and many other EGUs—is estimated at $990.67 per ton of urea, whereas the cost estimates for optimizing existing SCRs assumed a cost of only $350 per ton of urea. For a source that already has an SCR that it operates continuously and in an optimized state, the "cost of compliance" of $1,800 per ton to optimize an existing SCR is meaningless; it cannot represent the true cost of compliance for that unit. That unit will always have to purchase allowances to comply with the regulation if emissions exceed a daily or seasonal limit (*i.e.*, due to SSM events, which are not considered in the proposed rule).

Response:

Preamble section VI.B.7 describes the final rule's daily backstop rate implementation. See the EGU NO_X Mitigation Strategies Final Rule TSD and Section 10.8 for description and response to comments regarding the EPA's incorporation of urea price volatility.

4.3.5.2 Cost Per Ton Threshold / Emission Reduction Assumptions

Comments:

Commenter (0290) suggests units that have efficient combustion controls and operate at lower NO_X levels (*i.e.,* less than0.14 lb NO_X /MMBtu) would have a much smaller number of tons reduced with an SCR resulting in a significantly higher $/ton cost. According to the commenter, this is amplified with low-capacity factor units (*i.e.*, less than the 56 percent capacity factor used by the EPA) or units that intend to operate for less than five years after the required 2026 implementation date. The commenter is committed to developing a cleaner alternative to coal by 2030. However, they point out that, under this scenario, the SCR would only operate for four years at the most from the 2026 implementation date. Using a 4-year operating life increase the capital recovery factor (CRF) and significantly increase the cost-effectiveness of the SCR. Based on a 4-year operating life and assuming the same discount rate used in the EPA's analysis, the commenter asserts that the capital recovery factor would go from 0.143 to 0.325. Cost-effectiveness of retrofit SCR is a function of the assumed operating life of the control equipment. In their case, the commenter states that the cost-effectiveness of retrofit SCR for one of their units (JK Spruce), which has an anticipated retirement date around 2030 is greater than $57,000/ton, which is significantly higher than the $11,000/ton threshold assumed by the EPA. The commenter urges the EPA to consider allowing coal-fired units that attest to a reasonable shutdown date to operate beyond the 2026 implementation date.

Commenter (0300) states the EPA underestimates the cost per ton of NO_X emissions reductions by calculating the cost on an annual basis. The commenter asserts that since NO_X reductions required by the proposed FIP only occur during the NO_X ozone season, defined by the rule as the five-month period from May through September, the cost per ton of emissions should only be calculated over this five-month period; therefore, when appropriately calculated, the cost per ton of emissions reduced will actually be 2.4 times greater than what is anticipated by the EPA through the implementation of this rule.

Commenter (0300) also states the EPA arbitrarily set a cost per ton threshold of $7,500 when evaluating potential NO_X control technologies for non-EGU sources using a “one size fits all” approach for addressing the estimated cost and actual emissions reductions achievable, particularly for existing sources of NO_X emissions. The commenter believes the EPA cannot apply such a vague cost application and then impose a standard on existing and new sources that may not be achievable at the cost threshold specified and may not be technically feasible for existing sources to retrofit. To illustrate complications (which cannot be considered without performing unit-specific analyses) related to or involve with retrofitting existing burners with ultra-low NO_X burners, the commenter writes:

- Longer burner length requiring more space which may or may not be available for an existing source within a set footprint;
- Increased pressure drop resulting in the reevaluation of the adequacy of existing forced draft fans;
- Whether flue gas recirculation is required to achieve the stated efficiency or NO_X emissions rate, and;
- Evaluation of the furnace geometry to determine if the geometry adversely impacts the flame pattern/size required by the ultra-low NO_X burners.

Additionally, the EPA has calculated the cost per ton based on NO_X reductions achieved across the entire calendar year rather than NO_X reductions addressed under the “good neighbor” provisions of the CAA and defined as the “NO_X ozone season emissions” in the proposed rule (40 CFR 52.40).

Commenter (0351) states the proposed rule and the EGU NO_X Mitigation Strategies Proposed Rule TSD calculate that the cost-per-ton emissions-weighted average (for existing coal-fired EGUs with 100 MW or greater capacity and that do not already have installed post-combustion

NO_X -control technology) is $11,000 per ton, with a median of $13,700 per ton and a 90th percentile cost of $20,900 per ton. The commenter notes that there is discrepancy between the assumed loan life for an SCR retrofit, 15 years, and the four years of remaining operation at Sherco unit 3 between 2026 and the unit's retirement in 2030. The commenter also claims the cost-effectiveness threshold is too high for its specific facility.

Commenters (0372, 0409) believe that the EPA grossly underestimated the costs for NO_X reductions and cost baseline should be representative – only use states subject to the FIP to establish a cost baseline representative of the 25 states at issue. Additionally, the commenters state the EPA's estimates of SCR installation costs are underestimates based on dated backup information – *i.e.*, based on data and analysis from 2004 through 2013 with these data "significantly augmented' by S&L in-house data and fails to account for changes in variables, including a rise in interest rates. In general, the commenters support the adjusted version (*e.g.*, converting costs to 2021 dollars) of the capital cost relationship proposed by the S&L Cost Analysis developed by Sargent & Lundy. The commenters project the cost of the median coal-fired population at $17,508/ton, exceeding the EPA's reference case value of $15,500/ton.

Commenters (0372, 0409) believe that operating costs presented in the S&L Cost Analysis are underestimates due to the variable operations and maintenance (O&M) costs for SCR catalyst management. The commenters add that O&M costs vary due to the physical state of the catalyst and the ability to achieve a high degree of ammonia-to-NO_X uniformity. Results from the Sargent & Lundy study (the S&L Cost Analysis) report the incurred cost for a unit at the median population of $20,250 per ton for operation at 56% percent capacity factor, escalating to approximately $28,103 per ton for units at the 90% percent population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be $24,340 per ton, escalating to more than $50,000 per ton. In comparison, commenter (0372) states that downwind state sources in nonattainment areas are required to install Reasonably Available Control Technology (RACT)-level controls and the median RACT level controls cost is $9,581, as reported in the RBLC, and based on these finding the commenter claims that it is inequitable for upwind state sources to bear significantly higher controls costs. To illustrate that costs of $24,340 / $50,000 plus per ton for SCR installation are entirely out of balance with home state RACT costs, the commenter briefly discusses impacts of SCR installation on one of their non-SCR units, specifically Cooper Unit 1, and provides the result of performed cost calculations for SCR installation on this unit. The commenter offers a summary of key assumptions made and the following cost information based on the cost analysis performed: Capital Cost: $78,290,000 (est); Capacity Factor: 75 percent to 25 percent; Annual O&M: $1,838,000 to $1,351,000; and n$/ton controlled: $8,336 to $23,926. The commenter briefly mentions concerns over the possibility that the high costs associated with SCR installation, may be forced smaller units to retire. Additionally, commenter (0409) notes, that the same study reports that the cost per oil/gas unit is estimated at $18,429 per ton for operation at 56 percent capacity factor, escalating to approximately $32,000 per ton for units at the 90 percent population. For operation at the 2021 capacity factor, the cost for the median population is $ 62,661 per ton, escalating to approximately $80,000 per ton for a unit at the 90 percent population. The commenter maintains that viewing technology projects on a cost per ton analysis does not illustrate the true costs realized by utilities – *i.e.*, utilities typically estimate the total project cost of the project in comparison to the benefit received.

Commenters (0372, 0409) state that existing SCRs must achieve the 0.070 lbs/mmBTU target rate to maintain a compliance margin. This requires enhanced O&M practices entailing accelerated catalyst replacement, aggressive catalyst cleaning, and annual tuning reagent injection equipment. Commenters recommend that these costs be included in the EPA's cost estimates. In regard to operational limits of SCRs, commenter (0372) believes that the EPA has proposed insufficient allocations to allow coal-fired units (including the commenter's unit(s)) with SCRs to operate at a utilization rate commensurate with 2021 (the EPA's base case); therefore, the only choice available is to attempt to lower SCR NO_X removal further or reduce unit capacity factors. The commenter reiterates that there are operational concerns (byproducts) caused by driving down NO_X rates – *e.g.*, cause corrosion issues and an increase in ammonia reagent. Commenter concludes that the EPA must consider these operational byproducts to SCR operation and recognize limits to the technology.

Commenter (0394) believes that the EPA's assumptions regarding the NO_X emissions reductions that can be achieved through the use of control technology – including state-of-the-art combustion controls and post- combustion NO_X controls – are unrealistic, in addition to the EPA's judgments regarding the cost of installing that control technology and optimizing the operation of controls that are already installed. More specifically, the commenter states in its modeling for the proposed rule, the EPA overestimated the ability of combustion control technologies to achieve very low NO_X emissions rates. The commenter explains that assumptions made (as discussed in the Technical Report) 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. In addition the commenter suggests that the EPA also ignore the role of boiler design features in achieving lower NO_X emissions rates, and fails to consider that retrofit of advanced combustion controls will not result in the same NO_X emissions rate reductions from older vintage boilers as it will with newer boiler designs, According to the commenter, Technical Report provides more realistic NO_X emissions rates that may be achieved on average, based on specified combinations of fuel types and firing equipment, most of which result in higher NO_X emissions rates than the EPA assumed. The commenter references its Technical Report and states:

- The retrofit of SCR to coal units incurs a cost for the median unit in the population that ranges from $20,250 per ton for operation at the 56 percent capacity factor, escalating to approximately $28,000 per ton for units at the 90 percent population.
- The retrofit of SCR to distillate oil/gas-fired units – which would apply to 35 units under the proposed rule – incurs a cost for the median unit that ranges from $11,000 per ton for operation at the 56 percent capacity factor and a 10-year remaining lifetime, to over $66,000 per ton for operation at the 2021 capacity factor and 5- year remaining lifetime.
- SNCR retrofit as EPA proposes – to coal-fired units of 100 MW generating capacity or less – captures only six units. The incurred cost for the median unit ranges from $12,645 per ton to more than $100,000 per ton at the 90% population, which reflects operation at the 2021 capacity factor and 5-year remaining lifetime.

- SCR retrofit costs exceed EPA's estimate incurred by the median unit of SCR retrofit of $15,500/ton for coal at the 56 percent capacity factor and for SNCR for the population of boilers less than 100 MW of $10,800/ton for coal application.

Commenter (0394) disagrees with the EPA's assumptions regarding NO_X emissions reduction performance for SNCRs; arguing that they are also unrealistic. The commenter points out that the EPA asserts that SNCR control capability ranges from 20 to 40 percent, depending on the application. According to the commenter, this estimate misjudges the complex procedure of introducing ammonia reagent during a narrow temperature window to optimize NO_X reduction, and the variability in NO_X emissions reduction that can occur during this process. The commenter insists that the upper limit of SNCR control capability for most units is 30 percent.

Commenter (0396) states the EPA's cost-effectiveness evaluations are incorrect. The EPA's proposal seems to be a thinly veiled attempt to impose SCR on all coal-fired units regardless of actual air quality benefits, particularly since the EPA's own cost-effectiveness analysis does not support its conclusions, and the assumptions underlying that analysis are incorrect. The EPA asserts that the cost-effectiveness of retrofit SCRs is $11,000 per ton, well above what it has relied upon in the CAA programs noted above. Moreover, the EPA's cost-effectiveness value of $11,000 per ton still does not accurately represent the EPA's own cost-effectiveness analysis because that value is a "weighted average". The median cost-effectiveness value in the EPA's analysis is $13,700, which means SCR is not cost-effective for at least half of the EGUs evaluated. The EPA's analysis also indicates that the cost-effectiveness value of SCR for ten percent of the EGUs regulated under the Proposal would be $20,900 per ton, nearly twice the benchmark used by the EPA and states in other programs. The commenter also states the EPA's cost-effectiveness analysis also fails to take into account the fact that costs are escalating more quickly than ever before. Labor shortages, commodity prices, the cost of capital, and supply chain constraints are likely to significantly increase the cost of controls far beyond what the EPA assumed in preparing its analysis.

Commenter (0397) states the EPA performed an evaluation of controls that would be available at incrementally larger cost-per-ton NO_X emissions reduction levels following a process where the EPA looked for natural "breaks" – cost levels where a relatively small increase in the cost of emissions controls would yield a relatively large quantity of NO_X reductions. The commenter briefly describes the AQAT tool used to determine whether the aggregate NO_X emissions reductions were sufficient to remedy all of the downwind nonattainment and maintenance issues The proposed FIP underestimates Oklahoma facilities that are subject to it and would result in over-control of Oklahoma NO_X emissions if finalized as proposed.

Commenter (0409) provides recalculations for Coal and Oil/Gas SNCR retrofits and combustion control costs. Coal-Fired Units: The re-calculated SNCR installation costs found a median population of $15,000 per ton for operation at 56 percent capacity factor, which increases to more than $40,000 per ton for units at the 90 percent population. If operation is at the 2021 capacity factor, the cost is $67,432 per ton. In contrast, the EPA found a cost per ton of $ 2,220 as a cost for restarting idled units. Oil/Gas-fired Units: The recalculated cost is $27,237 per ton for operation at 56 percent capacity factor, escalating to more than 100,000 per ton for units at the 90 percent population. When using a 2021 capacity factor, the cost is $117,628 per ton up to more than $250,000 per ton at the 90 percent population. The EPA reports a much lower cost per ton, with the highest cost example being a 100 MW unit operating at 26 percent capacity factor at $16,100/ton. Combustion control: using the capital, fixed O&M, and variable O&M provided by the EPA in the IPM 5.13 documentation, the total cost of installing advanced low NO_X firing equipment to a tangential-fired and wall-fired 300 MW boiler operating at 10,000 Btu/kW and 56 percent capacity factor is $3,345,200 and $2,055,529, respectively, using a 2021 escalated basis. On a per ton basis, the wall-fired boiler burning bituminous call incurs a cost of $4,506/ton to lower NO_X from 0.40 to 0.30 lbs./mmBtu. The tangential-fired boiler burning bituminous coal incurs a cost of $2,793/ton to lower NO_X from 0.35 to 0.25 lbs./mmBtu.

Commenter (0503) supports, in general, the $11,000 cost threshold for EGUs.

Commenter (0510) states the EPA developed its final EGU NO_X ozone season emissions budgets using a control stringency represented by $1,800 per ton. Ignoring the critical need for NO_X reductions, and instead focusing on the "knee in the curve" where air quality improvements and costs were balanced, resulted in a control cost that was a fraction of what has been utilized in the NYMA states for many years. This proposal's higher cost thresholds will allow for the much needed installation of new selective catalytic and non-catalytic reduction (SCR and SNCR) controls at high-emitting sources that are already commonplace in downwind nonattainment areas.

Commenter (0528) asserts that the EPA significantly overstate the cost-effectiveness of SCR installation; specifically, the EPA underestimated the costs necessary to install new NO_X controls – *i.e.*, marginal cost of $11,000 per ton for new SCRs is inconsistent with the real-world costs that fossil fuel-fired EGUs are facing, as detailed in Sargent & Lundy Technical Memorandum on NO_X Controls ("S&L NO_X Controls Memorandum"). The commenter states that when assessing the cost-effectiveness of SCR installation for EGUs (located in Texas) any timeframe longer than five years is inappropriate, particularly for units scheduled to retire after 2026. The commenter states that evaluating cost-effectiveness disconnected from the reality of EGU operations is unreasonable. This concern is compounded by the EPA's failure to account for current world events that are affecting the availability of materials and labor necessary for the installation and operation of new SCRs. The COVID-19 pandemic, labor shortages, supply chain delays, and the ongoing war in Ukraine are all factors that must be considered in assessing the cost of controls.

Commenter (0541) states the EPA cites a representative marginal cost for optimizing existing SCRs at $1,600 per ton while also noting that the cost is often under $900 per ton. Commenter maintains that the cost of replacing catalyst should be factored into the cost for increased NO_X removal because higher removal rates lead to increased catalyst deterioration and more frequent catalyst replacement. The commenter has found that aqueous ammonia prices are already inflated to nearly three times the cost a year ago: $0.223 per gallon of ammonia (NH3) compared to $0.095 per gallon. The commenter estimates current marginal NO_X reduction cost at its SCR equipped units (using a tri-variate calculation) to be $2,600- 3,800/ton NO_X at current aqueous ammonia costs. According to the commenter, ammonia slip is expected to increase with further NO_X reductions. To illustrate, the commenter states that the total marginal SCR optimization cost at current aqueous ammonia price, five percent ammonia slip, and assuming ammonia cost is 85 percent of total costs with a cost of $2,900 per ton.

Commenter (0554) states $11,000 per ton of reduction is not cost-effective. Even BACT determinations under the NSR program often rely on a cost-effectiveness threshold of only $10,000 per ton of reduced emissions. In the TSD, the EPA's supporting analysis indicates a median cost-effectiveness value of $13,700/ton and a 90th percentile value of $20,900/ton. These values mean that for half of the units affected, cost-effectiveness will be at least $13,700/ton, and ten percent of the units will see a cost-effectiveness of $20,900/ton or more. These values are even further out of step with the EPA's prior cost-effectiveness evaluations than the $11,000 figure it cites and confirm that the SCRs required by the EPA's one-size-fits-all backstop limit are not cost effective at all. In addition, the commenter states TSD does not explain why the EPA determines SCR remains cost effective on SNCR-equipped units. It simply provides additional calculations confirming that the cost effectiveness for such units would be $13,400/ton on a weighted average, with a median value of $14,100/ton and a 90th percentile value of $19,000/ton. These values confirm installing SCR on an EGU already equipped with SNCR is not in fact cost effective as defined by the EPA or any reasonable person.

Commenter (0547) believes that the use of a uniform retrofit factor is not appropriate, especially for the unique challenges faced by units with existing SNCRs – existing permit limits and requirements, the SNCR cannot be taken out of commission to allow for installation of the SCR, and rather, as there is limited space available for the control equipment on a unit, the SCR must be installed and constructed in the available space. To illustrate, the commenter provides a brief overview of installation of SNCR for two of their units (Unit 2 and Unit 3, located at Laramie River Station).

Commenter (0547) believes, in general, that estimated retrofit costs of SCRs are underestimated and thus, SCR retrofit systems are not cost-effective, especially at units with SNCRs. The commenter recalls a few moments where the EPA admits or recognizes that these "representative" costs do not represent the costs for retrofit of SCRs at units with SNCRs; further acknowledging that the costs will be higher for these units because "this subset of units has different characteristics than the wider fleet." Commenter cites the summary worksheet titled, NO_X Control Retrofit Cost Tool Fleetwide Assessment Proposed CSAPR 2015 NAAQS, as support (see EPA-HQ-OAR-2021-0668-0113). Finally, the commenter suggests that the EPA update its costs to reflect the current market conditions, which are excluded in the Coal-Fired SCR Cost Methodology that is based on trends from 2010 to 2020.

Response:

See Section V.B.1 of the preamble and the EGU NO_X Mitigation Strategies Final Rule TSD for details on the EPA's derivation of a representative cost threshold for SCR retrofit on EGUs as well as a general response to these comments. In addition, the role of the $7,500/ton threshold used in the Screening Assessment for non-EGUs is discussed in Sections V.C and V.D of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment). Implementation considerations for non-EGUs are discussed throughout Section VI.C of the preamble.

Because what may be considered cost-effective must be evaluated in the context of the particular regulatory program being implemented, it does not make sense to compare cost-per-ton numbers used in previous transport rulemakings (for less protective NAAQS) or in other regulatory contexts as absolute benchmarks against which to compare the cost-per-ton figures evaluated in this action. However, we note that as between upwind contributing states and downwind states with ozone nonattainment obligations, in general, the latter jurisdictions have been required to implement relatively costly ozone-precursor emissions controls, in many cases well exceeding the stringency or cost-per-ton values in this rule. This is a relevant factor for the Agency to consider in determining an appropriate level of emissions control stringency under the good neighbor provision. *See EME Homer City*, 572 U.S. 489, 519 (CSAPR is "[e]quitable 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 bring down their emissions by installing devices of the kind in which neighboring States have already invested."). *See also Maryland v. EPA*, 958 F.3d 1185, 1200-01 (D.C. Cir. 2020) ("To equalize the burdens between upwind and downwind states, the Clean Air Act authorizes a state to petition the EPA for a finding [under CAA section 126(b)] that upwind emissions significantly contribute to that state's nonattainment of the ozone NAAQS.").

As EPA's Proposed and Final rule EGU NOx Mitigation Strategies TSD highlighted, there is a distribution of cost for retrofits that varies based on each individual unit's configuration and operation. EPA uses a representative cost value associated with different pollution control technologies, which is informed by the weighted average cost to retrofit at the units identified as having retrofit potential for that technology. EPA's analysis incorporates both the median cost and the 90th percentile cost. A weighted average cost is most appropriate for a representative cost in the case of retrofits as it best reflects the cost per ton reduced with a given technology. With the capital intensive retrofit options, the weighted average cost appropriately captures historical compliance patterns where units with costs below the fleet representative value are more likely to pursue this mitigation strategy. Alternatively, for variable cost strategies, such as operating existing controls, where nearly universal adoption is expected – EPA relies on the 90th percentile cost. The cost are described as "representative" because they are representative of a particular degree of emissions control stringency across the group of sources with this mitigation potential. They are not a price ceiling or upper bound on this mitigation strategy's cost at every unit with such potential.

Commenters above make claims that the representative cost would be higher, such as $28,000 per ton, $66,000 per ton or even $100,000 per ton for SCR or SNCR retrofits (one even asserts $250,000 per ton, although EPA could find no underlying calculation to evaluate in that instance). These commenters generally misconstrue the representative nature of the value in the following manners. First, the largest cost numbers are often citing the estimated cost of the 90th percentile unit rather than the weighted average dollar per ton cost. These reflect the units facing relatively high-cost retrofits, which are not representative of the cost for this mitigation strategy for the fleet segment. Second, they make a suite of alternative assumptions relative to those made by EPA, which puts upward pressure on the resulting cost figures. For instance, whereas EPA assumes a book life of 15 years reflecting a reasonable assumption for units likely to retrofit, the commenter assumes a much shorter book life and therefore inflates the annualized capital cost. They also use alternative capacity factors, such as from a single historical year, instead of the expected capacity factor for a unit that is likely to continue to operate. This alternative produces some extreme-cost outliers (that are conceptual in nature, not forecasted or likely) that the commenter then portrays as representative. For instance, if a source rarely operated or operated at a very low capacity factor in 2021, then retrofitting that unit would produce very little reductions to spread out the capital cost, and naturally produce a very high dollar per ton number. This again is a conceptual exercise by the commenter aimed at producing a high cost-per-ton figure, not a representative retrofit cost for a particular technology to a general group of sources. Moreover, some commenters combine these "outlier" assumptions in a manner that has a compounding affect, producing extremely large cost-per-ton values. Other factors on which commenters make different assumptions to the same effect include the input-NO_X rate, which cost-inflation index to use, the assumed use of more expensive EPC-vendor contracts, and interest rates. EPA also notes that one commenter suggested there is a high dollar per ton figure for SNCR on oil/gas steam units, but this is not a mitigation strategy included in EPA's determination of stringency.

The EPA also notes that commenter values are often presented in mid-2021 dollars, and while they usually also present EPA's calculations in 2021 dollars, the EPA has chosen to use 2016 dollars for consistency across this rulemaking Therefore, care should be taken in comparing figures calculated by commenters and those presented in EPA's analysis. See Section 4.3 of this document for further response to comment on the issue of inflation.

With respect to EGUs: Some commenters claimed that units with older (pre-2005) SCRs would have to make significant investments in hardware or enhanced O&M to achieve operating at a 0.08 lb/mmBtu NOX rate. The EPA looked at the reported emissions from the past 6 ozone seasons (2017 to 2022) for units with pre-2005 SCRs and found that even units with older SCRs were widely capable of achieving emission rates below 0.08 lbs/mmBtu. First, the EPA looked at the lowest and third lowest season NOX rate from 2017 to 2022 for 74 coal-fired units with pre-2005 SCRs. EPA found that these units had average emission rates of 0.072 lb/MMBtu and 0.089 lb/MMBtu using the lowest and third lowest ozone season rate for each unit. Additionally, more than half of the units (38) had a third lowest emission rate (2017 to 2022) lower than 0.08 lb/MMBtu and 54 units had their lowest seasonal emissions rate (2017 to 2022) below 0.08 lbs/mmBtu. The data further suggests that several units were not operating their SCRs particularly effectively, if at all, over this time period, which create an upward bias in those averages. Second, the EPA also looked at the 2022 ozone season emissions rate data for these 74 units and found 42 units – more than half – had a seasonal average NOX emissions rate below 0.08 lb/mmBtu, with another dozen at or below 0.09 lb/mmBtu. This data strongly indicates that even units with older vintage SCRs are broadly capable of operating at or below the 0.08 lb/MMBtu level assumed in the engineering analysis without requiring expensive hardware upgrades or O&M particularly more extensive than normal.

Some commenters suggest that they would need to over comply to meet the assumed mitigation rate (e.g., operate at 0.07 lb/mmBtu to meet EPA's assumed 0.08 lb/mmBtu rate for optimization. However, the fleet rate used for budget purposes represents a fleet average for units exercising that strategy, not a unit-level requirement.

Commenter cites past examples of RACT in downwind states being less costly than the stringency required in this rule. We disagree that this is an apt comparison. First, this cherry picks lower-cost RACT determinations and fails to mention instances of higher cost RACT in downwind states (e.g., New Jersey has adopted NOx RACT rules determining that control costs are reasonable at levels up to $18,000 ton for boilers and up to $44,000/ton for "high electric demand day" turbines. See Table 5 of New Jersey's "State Implementation Plan Revision for the Infrastructure and Transport Requirements for the 8-hour Ozone National Ambient Air Quality Standards and Negative Declaration for the Oil and Natural Gas Control Techniques Guidelines" (2019)). Second, it ignores that even those instances of lower RACT values cited are lower, in many cases, because they are using assumptions different than what the commenter is using (e.g., a higher capacity factor, book life, etc). In summary, commenter is not providing apples-to-apples estimates.

With regard to comments suggesting the EPA's representative cost-per-ton values at Step 3 should be 2.4 times greater to account for the ozone season being only 5 months of the year, it is not clear how this would change the EPA's analysis, since the cost figures would still be used in a representative and relative way, in order to compare the stringencies of control alternatives within the Step 3 multifactor test. In any case, we have used annual cost-per-ton figures throughout the history of transport rulemakings and see no reason to reopen or alter this approach here. Additionally, the entire, system-wide compliance costs that could be borne by facilities (capital, O&M, Overhead, etc.) are reflected in the RIA. The total cost of the rule and the total ozone season reductions are appropriately described. t

For the representative cost used to describe mitigation measures in the EPA's Step 3 analysis, the EPA presents the total cost of the SCR annualized over the expected annual reduction in tons. This is 1) consistent with RACT (Under the CAA, all areas designated Moderate nonattainment for the 2015 8-hr ozone standard are required to implement RACT for all existing major sources of VOCs or NOx, and that cost is calculated using annual tons in the RACT economic feasibility assessment); 2) consistent with historical data that shows controls tend to operate annually in most cases once installed; and 3) consistent with how the EPA has described these costs in all prior "good neighbor" rules issued by the EPA.

In regard to comment claiming the upper limit on SNCR performance is 30 percent, not 40 percent, EPA notes that the value used in both its IPM modeling (informing regulatory impact analysis) and Engineering Analysis (informing state budget quantification) is 25 percent for new SNCR retrofit on non-circulating fluidized bed (CFB) units (CFB units are able to achieve 50 percent reductions in NOx with SNCR as described in the "Coal-Fired SNCR Cost Methodology" report in the docket). The value used for SNCR optimization is a historical-based unit-specific value in the Engineering Analysis (informing state budget quantification) that is under 25 percent on average. The EPA's SNCR retrofit and optimization assumptions are within the levels highlighted by commenter.

The EPA also notes that the Technical Report (Cichanowicz et al) states, "The highest NOx removal allowed for units with (a) boiler NOx emissions rates of 0.15 lbs/MBtu or less, and (b) boiler of 200 MW and higher is limited to 30 percent." In the engineering analysis, the EPA applies emissions reductions commensurate with SNCR retrofit to two sets of units: coal fired circulating fluidized bed units (which can achieve reductions of 50 percent with SNCR) and coal-fired units under 100 MW. Therefore, the report cited does not provide an applicable limit for SNCR performance for units under 200 MW.

While the EPA uses a nationwide representative cost of SCR retrofit for Step 3 purposes, the IPM runs examining the cost and geography of this final rule calculate SCR and SNCR cost specific to individual units within the states covered by this rule that are projected to retrofit SCR or SNCR. Finally, the EPA conducted a sensitivity analysis limiting the Step 3 cost analysis for EGU SCR and SNCR to historical data from units in states covered by this final rule. This analysis can be found in Appendix B of the EGU NOx Mitigation Strategies Final Rule TSD.

In regard to JK Spruce, Sherco, and other units that have SCR retrofit potential and near-term retirements, see Section V.B.2 of the preamble and section 4.3.4 of this document.

In regard to comment that SNCR-controlled units cannot reasonably retrofit with SCR, EPA observes that SNCR systems typically occupy a significantly smaller portion of space than an SCR requires. SNCR equipment can be removed or abandoned in-place for installation of other equipment (which includes a SCR). SCR retrofit suppliers have faced the issue of replacing SNCR with SCR many times with previous programs and were able to successfully retrofit an SCR by making the necessary modifications to an existing EGU. Some existing equipment may need to be relocated and/or additional duct work installed to accommodate an SCR but engineers have previously overcome these obstacles, including at the following units: Indian River unit 4; Hudson unit 2; Mercer units 1 & 2; WH Sammis units 6 & 7; El Segundo unit 4; Asheville unit 2; Cardinal unit 1; Marshall unit 3; Scattergood Generation Station units 1 & 2; Etiwanda generating Station units 3 & 4; Merrimack unit 1; and Seward Generating Station unit 15. Finally, EPA notes there are only a limited number of units (18) across the entire region that potentially fit into this category, the rule has no unit-specific retrofit requirement and the majority of these units have retirement dates planned for 2030 or earlier.

In regard to comment asserting that only a fraction of the proposed EGU baseline tons need to be eliminated to secure attainment in receptors to which Oklahoma is linked, the record does not bear out these claims. Our overcontrol analysis is in Preamble Section V.D.4.

4.3.5.3 NO_X Emission Reduction Cost – Kentucky

Comments:

Commenter (0341) states the proposed FIP will have a significant negative impact on Kentucky’s economic development:

- The proposal uses inaccurate data that results in erroneous attainment modeling results that would penalize Kentucky and in turn threaten energy availability, energy security, and the ability of the state’s utilities to meet current and future economic development needs.
- To comply with the complex Good Neighbor FIP, the utilities with non-SCR units will need to add controls, convert to natural gas, install low nitrogen oxide (NO_X) emitting

electric generating units, or participate in a flawed emissions trading market. The potential 2,600 MWs of capacity shortfall in 2026 does not account for load growth related economic development.

- The rule penalizes Kentucky electric generating unit's history of NO_X over-control, implements unrealistic operating limits, and repeatedly ratchets down emissions indefinitely.
- The commenter cannot reconcile the over 21,000 GWh of generation shortfall in 2023 compared to actual generation in Kentucky in EPA's Integrated Planning Model (IPM) that this rule is based on. Energy may not be available for purchase to meet this shortfall in surrounding states.
- Compliance by installing SCR controls or converting existing asset to natural gas is technically possible; however, large capital investment in these aging units needs careful consideration. Further, uncertainty in other NAAQS and greenhouse gas regulations adds economic risk to the extended operation of these aging electric generating units.
- The rule will cause significant uncertainty in the impacted Group 3 allowance market. The market instability makes resource and compliance planning diff–cult - Group 3 allowances have already increased from hundreds of dollars per ton (prior to the revised CSAPR rule in 2021 impacting the 2021 and 2022 seasons) to over $30,000 per ton of NO_X since the rule was proposed. The commenter estimates that SCR installation costs for units in Kentucky range (from $10,000 to $70,000) dramatically based on life of facility, size, capacity factor, etc.

Response:

In regard to Kentucky's alleged "shortfall" of generation in EPA modeling, the EPA notes that the reported 2021operating levels (generation, heat input, and emissions) are utilized to derive the 2023, 2024, and 2025 preset state budgets at Step 3, and those budgets assume the same degree of heat input at the EGUs subject to this regulation as observed in 2021 (only incorporating planned changes). The commenter's premise that IPM projections condition state budget quantification is incorrect. In regards to future year IPM modeling, the EPA does observe that 2021 generation levels reported in the state are approximately 10 percent greater than those projected in the final rule 2023 IPM modeling for Step 1 and Step 2. If actual 2023 data end up more aligned with the larger 2021 reported value rather than the projected 2023 generation levels, emissions may be proportionately higher, and this would only tend to further affirm the linkages to downwind receptors identified for Kentucky in this final rule at those steps of the analysis.

See EGU NOx Mitigation Strategies Final Rule TSD Appendix B for sensitivity analysis exploring cost variation under different assumptions.

4.3.6 Non-EGUs

4.3.6.1 General Comments

Comments:

Commenter (0243) states the EPA should include an applicability threshold based on PTE rather than boiler heat capacity for non-EGU boilers in the chemical manufacturing sector.

Commenter (0347) states the EPA needs to evaluate the cost of any wet-to-dry process cement kiln conversion proposal and claims that the costs would not justify the action.

Response:

The basis for the non-EGU boilers applicability criteria is explained in the Final Non-EGU Sectors TSD, Section 6.a.

The final rule does not include any requirement to phase out long wet kilns and replace them with units like preheater/precalciner installations. Thus, no cost evaluation or justification for kiln conversion is required.

Comments:

Commenter (0359) requests justification on the $7,500 threshold for non-EGUs. The commenter also states that being part of this proposed transport rule will place West Virginia at a significant disadvantage when competing for new industry and economic development with other states that are not subject to the proposed FIP. In addition, the commenter questions the proposed reporting frequency and suggests that performance testing once per ozone season is more appropriate than requiring testing every six months due to the length of the ozone season (five months) in which the standard is applicable.

Response:

The $7,500 marginal cost/ton threshold reflected in the analytical framework in the non-EGU screening assessment was a relative 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.

We note that every state surrounding West Virginia is subject to the same emissions control requirements as the sources in West Virginia under this rule.

Comments:

Commenter (0405) asserts that the EPA's proposed emissions limitations for the majority of affected units in the iron and steel sector are based on the application of control technologies that are technically infeasible, and further asserts that the Agency have provided no evidence in the record that supports the assertion that these controls are technically feasible.

Commenter (0504) states if the EPA cannot conclusively identify the technology to be applied, it cannot conclude that the technology is cost-effective.

Response:

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, and EAFs at this time. Reheat furnaces and certain industrial boilers are the only emissions units within Iron and Steel Mills and Ferroalloying Manufacturing for which the EPA is finalizing requirements. The EPA has provided its rationale for regulating these emissions units in Section VI.C of the preamble and in Sections 4 and 6 of the Final Non-EGU Sectors TSD.

Comment:

Commenter (0516) states the EPA's assumption that cement plants in the affected states did not have existing controls and therefore could be controlled easily at a reasonable cost is false. In evaluating emissions reductions and cost of controls to evaluate the cement industry in Step 2, the EPA continued to use false assumptions in place of readily available accurate data. The EPA used projected 2023 NO_X emissions that are 9 percent higher than the 2016 baseline emissions. Actual emissions trends are going down; 2019 emissions of 11 percent were lower than the 2016 baseline.

Response:

We disagree with the commenter's claim that the EPA's evaluation of potential emissions reductions and costs of controls for the cement industry was inadequate. We respond to these comments in Section 2.2.2 (Air Quality Thresholds for Identifying Impactful Industries), Section 2.2.4 (Screening Assessment -- $7,500/ton Threshold), and Section 2.2.5 (Comments that Facilities are Already Well-Controlled).

4.3.6.2 Cost Per Ton Threshold

Comments:

Commenter (0504) claims that EAF steel producers do not have significant contributions of NO_X that can be controlled on a feasible and cost-effective basis. The EPA relied on state emissions inventories which are most often based on sources reporting annual actual NO_X emissions on a facility-wide basis rather than a per-unit basis. This inventory does not include the more granular details necessary to identify technology strategies for installing or optimizing controls on specific units or even particular types of units. The EPA also failed to contact pollution control technology vendors. While vendors would likely have difficulty assessing the efficacy and cost of installing pollution control technologies on emissions units that have never been controlled with these technologies, vendor estimates could at least provide a starting point for a more refined and reasonably considered assessment of control costs in the non-EGU sectors, and particularly for emissions units at EAF facilities. The EPA's cost assessment also seemingly fails to consider the significant costs uniquely associated with force-fitting SCR at EAF facilities. The commenter provides abundant cost analysis examples to support its statements.

Response:

The EPA is not including emissions limits for EAFs in the final rule.

Comments:

Commenter (0510) states that data shows NO_X reductions could be achieved at costs ranging from $3,350 to $6,870 per ton of NO_X reduced (in approximate 2022 dollars) - below the marginal cost threshold of $7,500 per ton of NO_X utilized by the EPA for the other non-EGU source categories. The commenter is currently drafting a Memorandum of Understanding to pursue additional NO_X reductions from MWCs in the OTR .

Commenter (0526) states the EPA underestimates costs of SNCR in MWCs and references a report for an estimated cost of $31,000/ton. The commenter asserts the EPA's estimates also do not account for the global supply chain problems that exist as the world economies continue to recover from a global pandemic and other economic disruptors including global geopolitical conflicts.

Response:

The EPA has responded to these comments in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment) and Section VI.C.6 of the preamble, *Emissions Limits and Rationale.*

Comments:

Commenter (0516) states the EPA's cost-per-ton reduction calculations are unreasonably skewed because the EPA assumes that SCR will be run all year at cement facilities that have it installed and then calculates expected cost per ton on the basis of annual tons of NO_X reduced, despite the fact that the NO_X emissions reductions being sought by the EPA in the proposed rule are only to address ozone season emissions.

Commenter (0518) states, in addition to SCR retrofit costs, that the EPA's cost-per-ton reduction calculations are unreasonably skewed because they assume that SCR will be run all year at facilities that install it and calculates expected cost per ton on the basis of annual tons of NO_X reduced, despite the fact that the NO_X emissions reductions being sought by the EPA in the proposed rule are only to address ozone season emissions. The commenter also states cost annualization should account for the fact that reductions are not needed after 2028 in Arkansas. Moreover, the commenter states the rule is lacking in any analysis that would support including the Taconite Industry, on its own or as part of the Iron and Steel and Ferroalloy Manufacturing Industry.

Response:

The EPA disagrees that the cost per ton is skewed. The $7,500 marginal cost/ton threshold reflected in the analytical framework in the non-EGU screening assessment was a relative cost/ton level. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities (which also use annual cost/ton values), 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. This topic is further addressed in Section V of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).

4.4 The EPA's Assessment of Cost, Nitrogen Oxides (NOx) Reductions, and Air Quality

Comments:

Commenter (0499) requests that the EPA reconsider the proposed FIP due to the extremely high costs that will result for Louisiana electricity consumers. As stated elsewhere in these comments, the commenter believes that there are numerous flaws in the EPA's technical evaluations and modeling and the resulting conclusions related to alleged ozone impacts by Louisiana sources. The commenter also asserts that the EPA has failed to adequately consider the actual impact caused by mobile sources to ambient air quality monitors in most if not all of the 26 states impacted by the proposed FIP.

The commenter (0499) further believes that if the EPA finalizes the FIP as currently proposed, it will cause a significant financial hardship on both the regulated community and the residents of Louisiana without a measurable benefit to the air quality in the allegedly impacted ozone nonattainment areas. The commenter provides that, for example, the EPA's estimated number of required controls-retrofits indicates that Louisiana utilities will be required to install an amount of controls with an estimated expense of over $1 billion if the EPA finalizes the proposed FIP in its current form.

Response:

The EPA incorporates emissions from the mobile sector into its emissions inventories and it subsequently measures the impact of those emissions on downwind air quality using it CAMx model. See preamble Section IV for more discussion. The RIA discusses retail electricity rate impacts. For Louisiana specifically, the emissions reduction potential identified at full implementation of the rule for EGUs is largely assumed to occur at a subset of units representing approximately 6 TWh of the state's 45 TWh (*i.e.*, 13 percent) of reported 2021 ozone season generation (see EIA Form 923 for 2021), while the majority of affected EGUs in Louisiana are assumed to continue operating as they did in 2021 for the purposes of preset state budget quantification.

Comments:

Commenter (0317) states the EPA calculates costs annually for a program that is imposed only during the ozone season. Effectively, the EPA has cut the cost by more than half without any basis for doing so. The EPA has also failed to account for planned retirements in calculating costs. Applying an artificial 15-year in-service period for controls when the EPA knows that certain planned retirements will occur within six years is indefensible. A 15-year projected life is arbitrary and would significantly raise costs to consumers. Furthermore, even the EPA's assumed 15-year life is unreasonable when applied to many generating units in Arkansas which are subject to firm commitments which limit their remaining lives to no more than five years beyond the year (2026) in which the EPA is presumed that SCR retrofits would be placed into service on these units. The commenter analyzes its units and comes up with higher cost-effectiveness dollar values.

Commenter (0500) states the EPA states that the book life for a new SCR is assumed to be 15 years, and the cost assumptions used to estimate the dollar per ton of NO_X removal are tied to this assumed 15-year capital cost recovery period. However, in many cases, the actual unit-specific cost recovery period for an assumed 2026 SCR installation would be significantly less than 15 years due to planned unit retirements, resulting in a significantly higher dollar per ton cost of NO_X removal than the $11,000 per ton cost assumed by the EPA.

Commenter (0395) states cost calculations incorrectly assume a 15-year amortization of costs. This is not consistent with any other expectation for these units, including the EPA's. It completely contradicts the Administration's goal of a carbon neutral power sector by 2035. It also ignores the other regulatory pressures on such units.

Commenter (0355) states the proposed rule makes no analysis of the costs or the ability of generating facility owners to adapt to the rule toto protect the reliability of the electric system. The commenter also states the EPA's cost analysis improperly assumes that any SCR installed would be in-service for at least 15 years. Given the age of many of the units identified for such retrofits, this is an unsupported and unreasonable assumption. The EPA's cost analysis fails to consider existing public and enforceable retirement dates for some units identified for SCR retrofits. The EPA's cost analysis is inadequate without considering the impact of the SCR retrofit on those units. The commenter urges the EPA to consider an exemption for those units already set to retire within a certain timeframe after the implementation of the Dynamic Budget.

Commenters (0363, 0364) state the EPA should evaluate costs and benefits of compliance in light of the shortened operational life of EGUs and requests the EPA to expand exemptions from the FIP to include considerations of both nameplate capacity and time of operation.

Commenter (0546) states the EPA should consider the remaining useful life of a unit when calculating costs and provides examples of its facilities.

Response:

The EPA addresses the 15 year book life assumption and corresponding comment in preamble Section V.B.1.e SCR optimization cost is predominantly variable cost and hence does not vary notably in cost-per-ton regardless of whether the unit is optimized across the ozone season or annually. In regard to representative cost estimates for SCR retrofit at large coal plants, the EPA explains its analysis and response to comments in preamble Section V and the EGU NO_X Mitigation Strategies Final Rule TSD. Moreover, the EPA notes its $11,000 per ton representative cost is in line with the cost estimates provided by Arkansas itself in its SIP submittal for the 2015 Ozone NAAQS (noted unit cost for SCR retrofit at large coal units in Arkansas ranging from $6,000 to $16,000 per ton (almost perfectly bracketing a $11,000 per ton representative figure) on page 90 at https://www.adeq.state.ar.us/air/planning/sip/pdfs/2015/final-2015-ozone-naaqs-infrastructure-and-transport-sip.pdf).

Comment:

Commenter (0318) requests the EPA commit to reassess the FIP NO_X reductions, analytical tools, and methodologies in the light of new air monitoring information at the end of every ozone season to ensure that anticipated reductions were sufficient for all monitored areas to make progress towards meeting the ozone standard by the applicable attainment date. If necessary, further reductions should be implemented in the next ozone season through a contingency measure mechanism.

This proposal's 0.1 ppb reduction in ozone concentrations at Wisconsin's nonattainment and maintenance monitors in 2023 is only a fraction of what is required to address this upwind state contribution. Analyses of other years yield similar results, meaning the rule overall fails to properly address the significant contributions of upwind states to Wisconsin

Response:

The EPA is finalizing a full remedy for the upwind states subject to a FIP in this rulemaking. See Section V.D of the preamble for EPA's consideration of air quality impacts. Table V.D.2-2 indicates that in 2026 the Sheboygan receptor in Wisconsin is estimated to have a 0.56 ppb improvement in air quality based on EGU and non-EGU reductions (based on average DV). The 2023 ppb improvement ranges from 0.1 ppb to 0.18 ppb.

Comments:

Commenter (0357) states there are practical impacts to be considered as the EPA is considering the costs of additional controls necessitated by this rule. Specifically, although the CSAPR rule for the 2008 standard found that a reasonable control cost was $1,800 per ton NO_X, the proposed rule, considered here, finds that $7,500 per ton is reasonable. The cost of allowances associated with the 2008 standard do not reflect the EPA's reasonable control cost. As an example, Ohio NO_X allowance prices under the current system recently increased to $26,000 per ton which is incongruent with the EPA's reasonable cost of control. Unpredictable and unreasonably high NO_X allowance prices can impact dispatching decisions. The commenter also notes that natural gas-fired combustion turbines provide supplemental power during peak-load periods. Continuing to regulate these small natural gas peaking units under the rule in this manner will result in reliability and financial impacts.

Commenter (0395) states the Group 3 NO_X allowances for 2023, the year when optimization of existing SCR is the only control measure built into the allocations, allowances are already priced by the market at $28,500/ton, up from $6,500 four months prior, an increase more than four-fold. This is for a program that has not yet even been adopted and for a year with a static budget that requires only optimization of existing SCR/SNCR units which the EPA has identified has marginal cost of $1,600/ton. If the Proposal is adopted without change, the commenter expects that available allowances will be extremely scarce and higher in price as 2026 approaches. Starting in 2025, the commenter anticipates that companies subject to CSAPR will reserve any excess allowances for their own use in 2026 when the SCR retrofit allocations apply and then for 2027 when the backstop measure applies to coal-fired units retrofitted with SCR. If any allowances are offered into the market, the commenter expects that they will be offered at a rate many times higher than the EPA cost estimate of $11,000/ton.

Response:

The EPA notes that from 2017 through 2021, allowance prices (for programs assuming optimization) were near or below the EPA's $1,800 per ton estimate referenced in the comment. The allowance price increase that was observed in the summer of 2022 has since declined nearly 66 percent from its peak (see "CSAPR Allowance Price Data" in the docket). The EPA notes that CSAPR Group 3 allowances prices have ranged between $14,000 and $16,000 per allowance since the beginning of 2023. In as much as this price reflects market participants anticipating a final regulation similar to that which was proposed, it is notable that the prices are close to the representative SCR retrofit costs that EPA has calculated.

Moreover, the allowance price does not reflect the total direct cost to sources. Most sources have all or nearly all of their allowances allocated freely and are only procuring a small amount of allowances. The volume of allowances traded among unrelated entities during the price increase alluded to above was less than 10 percent of the overall Group 3 allowances available. (The EPA notes that the allowance prices reported by S&P Global Market Intelligence are the average of the bid and ask prices. The prices do *not* represent prices paid in actual allowance trades). We also note that the observed or apparent increase in allowance prices did not reflect scarcity of allowances in comparison to total emissions and thus the amount of allowances needed to comply with the current Group 3 trading program in 2022. In the 2022 ozone season, current data indicate a total of 90,458 tons of emissions, while the allowances available for compliance total 128,724 tons (consisting of the 103,705-ton total of the 2022 state emissions budgets and 25,019 banked allowances from previous control periods).

Comments:

Commenter (0372) states the disruptions in Europe, resulting from the war between Russia and Ukraine, is impacting the global energy market. As a result of global issues, fuel availability, fuel price volatility, and general energy security threaten electricity reliability and affordability for consumers and manufacturers in Kentucky. Natural gas and coal pricing is skyrocketing affecting the pockets of rural Kentuckians. The proposed FIP further threatens energy availability and security in Kentucky. The proposed FIP suggests that the generation gap will be resolved by generation shifting. Yet, generation shifting has significant cost and reliability risks to Kentuckians, as regional generation availability and transmission capacity constraints will be compounded by the Rule. The commenter is concerned with the proposed FIP's disconnect between energy supply, environmental compliance, and economic development in Kentucky. Kentucky needs to remain competitive with surrounding states for new jobs, economic development, and low-cost energy.

Response:

See the preamble and RIA for responsive information about this final rule.

Comments:

Commenter (0395) also states proposed EGU controls are unlawful because they are unnecessary. The proposed Texas CSAPR existing source budget reflects that reduction from the 2021 NO_X budget of 51,251 down to a proposed 2023 budget of 38,188 and an estimated 2026 budget of 23,292 (not including dynamic budget implications). Essentially, the proposed budget cuts EGU emissions by more than 50 percent to achieve a statewide reduction in NO_X of 30 percent. However, as demonstrated by the IPM summer base case, Texas will achieve these reductions without any regulatory driver. Once the proposed regulatory limits are applied, EGU emissions will be decreased by almost 80 percent from 2021 levels. The EPA has not demonstrated the need for such dramatic and costly reductions required by the Proposal. The commenter also states proposed EGU controls are unlawful because they are not cost-effective. By the EPA's own estimate, the EPA's proposed FIP imposes approximately $22 billion of costs for a negligible ozone benefit. For example, the EPA projects an average air quality improvement at downwind receptors resulting from EGU reductions in 2023 to be only 0.11 ppb—less than one quarter of one percent of the NAAQS. Specifically, the EPA itself calculates that less than 15 percent of the identified 2026 benefits come from high day ozone exposure, despite ozone being the pollutant of interest in this rulemaking. The EPA seeks to combine the ozone benefits with coincident PM benefits to bolster its analysis and justify this rulemaking, but the EPA cannot justify its rule directing states to ensure ozone benefits on the basis of potential PM reductions, which is subject to its own NAAQS. In addition, the commenter notes the cost-effectiveness of SCR on well-controlled units is very low. And the EPA should limit applicability of coal retrofit further. The EPA considers the $11,000 mark to be a "breakpoint" and that units, such as those under 100 MW, with an average cost of control at $11,900/ton and a median of $15,500/ton are not cost effective. The commenter believes that there are other categories of units where implementation of SCR would fit this description as well. For example, in the Proposal's technical support documents, the EPA makes the assumption that coal-fired units with a pre-SCR NO_X emissions rate below 0.14 lb/mmBtu will not install SCR, presumably because the cost cannot be justified with the other controls already installed. Clearly that is an indication that the controls are not cost-effective for these well-controlled units.

Response:

The commenter's assertion that the IPM base case demonstrates that the state of Texas will achieve this rule's required emission reductions even without a regulatory driver is incorrect for at least two reasons. First, unlike regulatory requirements, model projections are not permanent and enforceable requirements contained in a state or federal implementation plan under the Clean Air Act; they provide no guarantee that the necessary emissions reductions to eliminate significant contribution will be achieved and enforced. See section III.B of the preamble. While EPA's models represent state-of-the-science and very well-informed representations of potential future outcomes, the actual future remains inherently uncertain, and a projection that emissions may decline is no substitute for regulatory requirements ensuring that emissions are reduced as necessary to eliminate significant contribution to nonattainment and interference with maintenance of a NAAQS. Second, the final rule's full implementation has a NO_X emissions budget for Texas of approximately 23,000 tons, while the final rule's IPM base case projects approximately 27,000 tons of ozone-season NO_X emissions from Texas EGUs in the 2026 model run-year. Therefore, notwithstanding that models do not constrain real-world emissions, EPA's IPM base case expects higher emissions from Texas EGUs than this rule quantifies in that state's 2023 ozone-season NO_X budget (contrary to commenter's suggestion). Furthermore, this final rule's air quality modeling shows that if the IPM base case projections for Texas EGUs (without this final rule) come to pass, the state's emissions would still contribute at or above 1% of the NAAQS to identified nonattainment and/or maintenance problems at downwind receptors, underscoring that further emission reductions from Texas sources (beyond those projected in the IPM base case) must be considered to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS.

The majority of the identified EGU NO_X emission reduction potential in Texas comes from uncontrolled sources reflecting less than 10 percent of the state's generation (i.e., 20 TWh of the state's approximately 227 TWh of 2021 ozone-season generation) (see Appendix A of the Ozone Transport Policy Analysis Final Rule TSD and the EIA Form 923 2021). Note that the EPA does not assume SCR retrofit on units already demonstrating a NOx emission rate of 0.08 lb/mmBtu or below.

Finally, the commenter's assertion that the ozone benefit is negligible is both incorrect and inconsistent with prior judicial direction. Preamble Section V.D shows the benefit to downwind receptors to which Texas is linked with implementation of the control strategies applied in Texas and other linked states, and the results show meaningful improvement in ozone levels at those receptors.

Comment:

Furthermore, commenter (0395) asserts the EPA's cost-effectiveness methodologies are flawed. The EPA should consider cost-effectiveness at the plant and unit level rather than the sector level toto determine a reasonable definition of "significant contribution." The EPA's efforts to rely on the same type of average, sector-wide cost-effectiveness analysis it previously performed for CSAPR rule updates is not supported by the record and looking to costs at a sector level is no longer appropriate. In the event the EPA does continue to consider average costs on a sector-wide level, as one part of its approach to defining "significant contribution," the EPA must also consider the costs of developing new capacity and generation. The EPA's cost-estimates for retrofitting coal-fired units with SCR are also flawed in how they limit the group of units included in the calculation.

Response:

The EPA explains its approach in Section V of the preamble and in Section 4.3.2 (Cost Threshold Limit).

Comment:

Commenter (0433) states operation of NO_X controls benefits regional haze. The commenter encourages the EPA to consider the potential co-benefits to improved visibility that could result from emissions reductions from this proposal and include those benefits in its cost assessments.

Response:

Chapter 5 of the Regulatory Impact Analysis accompanying the proposed FIP includes a qualitative discussion of visibility improvements associated with the proposal. These are again discussed in Chapter 5.4.5 of the final RIA. However, visibility benefits are outside the scope of the rule and not part of the record basis.

4.4.1 EGUs

Comment:

Commenter (0336) states in the spreadsheet entitled, proposal-appendix-a-proposed-rule-state-emissions-budget-calculations-and-engineering-analytics.xlsx, unit capacities in MW are provided in multiple tabs. However, some of the capacities for combined cycle operations do not appear to reflect the capacities supplied to the Energy Information Administration (EIA). Capacities as reflected in the spreadsheet are substantially less than those reported to Energy Information Administration. Calculations within this spreadsheet do not rely upon the capacity information. However, as a public-facing document, having the MW capacities of these units reflect actual capabilities is important. Commenter (0336) recommends either updating these values to better reflect the system capacities as reported to the Energy Information Administration or deleting this erroneous data from the spreadsheet.

Response:

The capacity values in the mentioned spreadsheet generally correspond to the NEEDS file for IPM which pulls in net summertime capacity from EIA 860 as reported in recent 2022 surveys. The EIA form shows multiple capacity values (nameplate, wintertime, summertime) that reflect slightly different capacity levels reflecting the generators performance as conditions change. As described in the IPM documentation, the EPA relies on summertime dependable capacity in its IPM modeling. The net summer capacity for all units was included in the proposal's engineering analysis as a reference and was not used in any calculations for the engineering analysis (when EPA applied a 100 MW applicability test for units that would retrofit SCR, it used the nameplate capacity factor listed in EIA 860 data).

Comments:

Commenter (0529) contends that the resulting impacts to customer rates will be notable. Due to the integrated systems, the commenter states that North Dakota customers have a vested cost-ownership in facilities that will be impacted by the proposed rules. The commenter has evaluated the costs of SCR installation for North Dakota regulated utilities and the resulting impacts on North Dakota customers and asserts that there will be a striking cost to implement SCR equipment necessary to meet the allowance window. The commenter provides that even a conservative estimation of SCR installation costs is prohibitive. The commenter notes that alternatively, stranded and replacement costs, increases in market energy prices, and additional transmission investment necessary to meet reliable service would be equally formidable.

The commenter (0499) encourages the EPA to reevaluate its determination that certain emissions control measures are universally cost-effective for certain kinds of EGUs. The commenter notes that the proposed FIP claims that SCR is cost-effective for all coal-fired EGUs greater than 100 MW, that SNCR is cost-effective for all coal-fired EGUs less than 100 MW in capacity, and that SCR is cost-effective for all natural gas-fired steam EGUs that emit more than 150 tons of NO_X during any one of the ozone seasons in 2019, 2020, and 2021. The commenter also notes that the EPA assumes that cost-effectiveness of retrofit SCRs is $11,000 per ton. See, 87 Fed. Reg. at 20,081. According to the commenter, this estimate is higher than what the EPA has historically relied upon in other CAA programs, and in some instances, much higher.

Furthermore, the commenter (0499) provides that the EPA's proposed cost-effectiveness value does not accurately represent the EPA's own cost-effectiveness analysis because that value is a "weighted average." The commenter states that the EPA claims this average is "representative" but does not explain why a weighted average is an appropriate metric for imposing a universal control requirement, when the EPA's analysis indicates that SCR is much less cost-effective for many EGUs. Based on the high variability of the cost-effectiveness values and the actual cost to install such equipment for certain units, the commenter asserts that the EPA has not demonstrated that SCR is universally cost-effective for all coal-fired EGUs.

The commenter (0499) also states that the EPA has made similar errors with respect to EGUs already equipped with SNCR. The commenter provides that the EPA's analysis confirms that cost-effectiveness values for EGUs with existing SNCR is $13,400 per ton, even on a weighted average, with a median of $14,100 per ton and a 90th percentile of $19,000 per ton. The commenter states the EPA has provided no justification for its assumptions and the EPA's TSD instead confirms that installing SCR on an EGU already equipped with SNCR is not cost-effective. The commenter reiterates that the EPA's cost-effectiveness values also underestimate the actual cost of installing control technology. For all of these reasons, the commenter requests that the EPA reconsider its cost-effectiveness analysis for SCR and SNCR especially in light of escalating costs, labor shortages, and current period of unprecedented inflation.

Response:

See above response to comment in this section and Section V.B.1 and C.1 of the preamble. The rule does not apply in North Dakota. The RIA presents information on projected economic effects.

Comments:

Commenter (0323) states the EPA's analysis of EGUs with SCRs installed considered a population of 226 units with 172 meeting the selection criteria in all states, but the EPA erroneously included in this total an additional 46 units in nine states not subject to the proposed rule, again rendering its conclusions inaccurate. The commenter also states the NO_X emissions rates cited by the EPA as attainable are based on fuel composition that cannot be extrapolated to the national inventory. The EPA does not acknowledge – especially for tangential-fired boilers firing bituminous–coal - that atypical reference fuels particularly the tangential-fired boilers prevent generalizing NO_X emissions rates from the small subset of boilers to the national inventory. The EPA's projection of low NO_X emissions rates is flawed, particularly for bituminous coal, as only three units are valid references while others represent atypical cases of western bituminous, refined coal, or are co-fired when reported as exclusive bituminous. The time required for installation – an average of 22 months based on a survey of 11 boilers - significantly exceeds the time available to enable retrofit for the 2023 ozone season. Additionally, the commenter references the Sargent & Lundy data and states the EPA's cost and feasibility analysis is erroneous.

Response:

In the final rule, the EPA's implementation schedule allows until 2024 for installation of combustion control, and up through 2027 to procure emissions reductions commensurate with installation of post-combustion controls (and up to 2030 before the daily backstop rate is applied for any large, coal-fired EGUs lacking SCRs). See the EGU NO_X Mitigation Strategies Final Rule TSD for discussion on installation timing of controls.

Comments:

Commenter (0366) states the EPA's methodology for computing cost-effectiveness disadvantages peaking units by assuming the 3-year average emissions rate approximates steady-state operations. While generally appropriate for baseload units, this methodology does not account for the highs and lows of peaking unit operations.

Commenter (0411) states the EPA underestimate the true cost and time required to install control equipment at affected facilities. This is especially true today as the economic assumptions, (*i.e.*, inflation, discount rate, fuel prices, chemical costs, commodity prices, transportation, and supply chain disruptions) are very different now than they were just one year ago and drastically different than five years ago. The commenter also states regulated utilities are not afforded the luxury to spend rate-payer's money on a speculative outcome without first justifying to state utility commissions that an expense is required. The commenter suggests the EPA should not reduce the allowance allocation for coal-fired units that already have a scheduled and approved retirement date without taking into consideration cost recovery timelines based on a unit's retirement date. The assumed emissions rate used to allocate allowances should be unchanged until the unit retires.

Response:

See Section V.B of the preamble and the EGU NO_X Mitigation Strategies Final Rule TSD for the EPA's evaluation of supply chain disruptions and other factors related to recent market volatility.

Comment:

Commenter (0502) fully supports the proposed rule and encourages it to move forward without delay to allow affected sources as much time as possible to prepare to meet requirements that begin in 2026. The commenter believes that the proposed rule provides a cost-effective pathway for upwind states to make the essential reductions in ozone that would allow downwind states opportunities to attain and maintain attainment/2015 ozone NAAQS, while also improving the air quality of affect upwind states. Commenter adds that many downwind states identified in the rule, such as Colorado, have higher background ozone levels that have become increasingly close to the EPA designated ozone design value as the ozone standard is lowered to better protect health. Furthermore, commenter (0502) applauds the EPA on the consistent and impartial approach used to determine sources that contribute to downwind nonattainment areas, to evaluate available control technologies that have been proven to reduce emissions, and to ensure that both source specific costs, as well as overall rule costs, are found to be cost effective. According to the commenter, the utilized approach is directly in-line with other established air quality rules and with previous legal rulings on the good neighbor provision; adding SCR – a proven technology – is the appropriate requirement for upwind sources to demonstrate compliance with the good neighbor provision of the CAA.

The commenter identifies the following specific areas of support:

- cost thresholds [are] appropriate and support the decision to have different cost thresholds for EGUs compared to non-EGUs.
- the required backstop emissions limits to ensure that control technologies are being utilized properly.
- the timelines for compliance and the immediate requirement to optimized existing control technologies, as well as the 2026 timeline for sources to complete retrofits to meet the established mass based limits.

Response:

Thank you for your comment.

Comment:

Commenter (0550) states the EPA projects that its proposed FIP would result in an average improvement to air quality at all downwind nonattainment and maintenance monitors of only 0.11 ppb in 2023 from restrictions on EGUs and an average improvement to air quality at downwind nonattainment and maintenance receptors of 0.43 ppb as a result of restrictions on EGUs. It shows EGUs are not the primary driver for compliance, and it may constitute overcontrol. The commenter also notes the EPA fails to account for the increased NO_X emissions due to the cycling of dispatchable units necessary to accommodate the predicted generation shifting.

Response:

The EGU NO_X Mitigation Strategies Final Rule TSD addresses unit cycling. Generation shifting is addressed in Section 5.b.1.f of the preamble.

Comment:

Commenter (0553) states the rule further regulating EGU NO_X budgets is not justified considering the very small benefit to downwind nonattainment and maintenance areas. The rule would also hamstring the current trading program through a series of additional constraints.

Response:

See preamble Section III for a description of the EPA statutory responsibility to eliminate significant contribution from upwind states. See Section V for determination of significant contribution and Section VI for how emissions reductions are implemented.

Comment:

Commenter (0782) states SCR is not cost-effective for its specific facilities.

Response:

See preamble Section V and the EGU NO_X Mitigation Strategies Final Rule TSD.

4.4.2 Non-EGUs

Comments:

Commenter (0338) states there have been significant reductions from stationary and mobile sources in Wisconsin over the past ten years. And the reduction in emissions from pulp and paper mills would have a negligible effect on air quality. For example, the maximum estimated improvement at any receptor for emissions controls on 25 pulp and paper mills is 0.0117 ppb, which is significantly below the detection limit of ambient air quality monitors. Thus, the benefit in air quality is too small to even measure.

Commenter (0403) states the ability to reach low ammonia slip without installing both combustion modifications and SCR is very low. Therefore, it is not accurate to represent cost effectiveness of SCR and combustion modifications to reach lower NO_X emissions limits as $7,500 per ton per year. Specifically, in its experience, installation of SCR costs about three times more than combustion modifications. Our estimated costs of installing SCR are about $17 million per engine, whereas low emissions combustion is about $4.5 million on a 3,200 horsepower 2-stroke lean-burn engine. Assuming a 50 percent operating duty (4,000 hours per year), cost effectiveness is over $23,000 per ton per year for combustion modification and over $100,000 per ton per year for SCR.

Response:

The role and details of the $7,500/ton threshold used in the Screening Assessment and the 0.01 ppb threshold used to remove industries from further evaluation in the Screening assessment is covered in Sections V.C and V.D of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment). In addition, we note that numerous changes have been made since proposal to ensure that the emissions reduction requirements of the final rule are cost-effective and reasonable. We have provided mechanisms for additional time to comply where shown to be necessary and for alternative emissions limits in cases of extreme economic hardship.

Comments:

Commenter (0545) states the EPA estimates that the proposal will necessitate NO_X emissions reductions at eight Wisconsin sources, including six pulp/paper mills and two glass product manufacturing facilities. However, because the EPA is relying on 2019 data, its estimates are woefully out of date. In particular, it should be emphasized that the most significant “Tier 2” contributor identified on the EPA’s list is a paper mill in Wisconsin Rapids. Per EPA’s modeling platform, the two boilers at this one mill are estimated to contribute more than 16 percent of the estimated NO_X emissions, or more than 1,000 tpy. However, the Wisconsin Rapids mill in question was idled in 2020 and has not operated regularly since that time. This obvious NO_X emissions reduction must be considered by the EPA but was not accounted for in the modeling.

Commenter (0329) questions how the EPA identified affected facilities and assumed NO_X reductions. The commenter reminds that they previously requested (and are still waiting) a copy/list of sources the EPA included in this proposal. The commenter contends that it is difficult to assess the impacts to states industrial facilities without this a comprehensive list of affected facilities. Despite not having the list of affected facilities, the commenter conducted a cursory review of current ozone season emissions from all point sources reporting 80 tons or more NO_X annually and are unable to account for the reductions the EPA has estimated.

Commenter (0505) continues, the EPA did not account for existing NO_X controls on one of the three glass furnaces it identified as subject to the proposal and has therefore overestimated the amount of NO_X emissions reductions from Texas glass furnaces. One of the three furnaces is equipped with oxy-firing and operates below the EPA’s proposed limit based on the most recent (2020) TCEQ emissions inventory data. Commenter (0505) concludes potentially affected Iron, Steel, and Ferroalloy Manufacturing sources in Texas were not included in the EPA’s analysis. Based on an analysis of TCEQ permit and 2020 NO_X emissions inventory data, an estimated eight sites may have applicable emissions units. The EPA’s analysis also did not include potentially affected Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. Based on an analysis of TCEQ permit and 2020 NO_X emissions inventory data, at least 20 sites may have applicable emissions units.

Commenter (0324) states the CoST model is general and lacks site-specific considerations. The commenter also notes the cost assessments in the proposed rule are annualized, whereas the emissions reductions and associated modeling impact are based on ozone season emissions.

Commenter (0329) states that based on the EPA’s analysis, it appears that non-EGU reductions in Minnesota have a greater improvement on the Illinois receptors that Minnesota impacts than EGU reductions. The commenter has been unable to account for these reductions based on its own analysis and requests that the EPA provide a list of the industrial facilities included in EPA’s analysis.

Commenter (0518) states one of the primary sources of information on the installation of controls the EPA relies upon in the proposed rule is more than 25 years old, from the 1998 NO_X SIP Call. The efficacy and timelines for controls based on 25-year-old data is undoubtedly an example of outdated information the EPA used that, if updated, would change the results of EPA’s assessment. The commenter notes in other areas of the assessment, the EPA relies on information in the 2016 CSAPR Update Non-EGU TSD, then elsewhere finds such information in the same TSD is “not complete or sufficient to serve as a foundation” for a different part of the rule. Such inconsistencies and data gaps confirm that the Agency should take a pause and obtain the best available data before taking the step of regulating non-EGUs across 23 states.

Commenter (0518) continues, the EPA also concedes it lacks information regarding existing controls on non-EGUs across multiple sectors. As a result, the EPA is still seeking foundational information on existing NO_X controls installed at non-EGU sources on which the EPA is proposing to require controls. Instead of reaching conclusions based on inadequate information, the EPA should first engage in information gathering from states and sources to ascertain the current level of controls through a NODA or other mechanism. It is unreasonable – and again a rush to judgment – to propose to mandate controls, without knowing whether controls are currently installed and already will be controlling future emissions.

Commenter (0353) states the $7,500 per ton non-EGU marginal cost threshold is not supported by the record. The proposed rule provides no explanation of what the EPA means by a "knee in the curve" of its cost threshold chart. There is no indication of why such a "knee" would be significant or how it relates to the cost per ton of emissions reduction. To the extent that the proposed rule meant that $7,500 per ton is the optimum cost threshold because there is a visible inflection point in the cost-benefit curve, this is not supported by the record. For Tier 1 point sources, which includes Stationary Engines, the Screening Memorandum's Figure 1 shows no evident "knee in the curve" at, or around, $7,500 per ton. The commenter raises three questions unanswered by the proposed rulemaking: (1) What is the justification for establishing a marginal cost threshold for Tier 1 industries by combining them with Tier 2 industry emissions control costs instead of using the costs for Tier 1 alone? (2) Even if using the combined Tier 1 and Tier 2 data, why did the EPA disregard the first "knee in the curve" occurring somewhere before $2,500 per ton and use the second "knee" at or around $7,500 per ton? (3) Why does the proposed rule select a much higher marginal cost threshold than in the 2021 Revised CSAPR Update Rule despite using the same data and the same analytical tools? Without providing an explanation to these questions, the Tier 1 industry marginal cost threshold lacks a rational basis and is unsupported by the record.

Response:

We respond to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluating potential emissions reductions from these industries, and evaluating related control costs (including the $7,500/ton threshold used in the Screening Assessment and the 0.01 ppb threshold used to remove industries from further evaluation in the Screening assessment) in Section 2.2 (Non-EGU Industry Screening Methodology).

Comments:

Commenter (0280) states the rule fails to recognize existing NO_X emissions reduction strategies already implemented by EAF operators. If the EPA applies its "40% NO_X reduction efficiency is achievable by use of low-NO_X technology, including potential use of low-NO_X burners and selective catalytic reduction" to this range, it would justify only limits of 0.30 to 0.36 lb NO_X /ton of steel, which is far above the proposed limit of 0.15 lb/ton set forth in the proposed rule. Therefore, either the data do not support the EPA's proposed limit or the EPA is relying upon far more than the 40 percent decrease stated in the preamble. The EPA, however, has not provided significant support for that assumption.

Commenter (0299) disagrees with specific limits for its facilities. The commenter also states preliminary calculations suggest that the site-specific cap limits will be significantly lower than the proposed ozone season limits, when converted into a lb/ton of clinker limit.

Commenter (0334) states the EPA did not consider the universe of pipeline engines and the costs will be higher than estimated. The commenter suggests that any engines already subject to NSPS JJJJ should only be required to comply with current NSPS subpart JJJJ requirements such that no additional emissions limits would apply, or revise the rule's emissions limit for two-stroke lean-burn engines from 3.0 g/hp-hr to 6.0 g/hp-br.

Commenter (0338) states the cost estimates are too low and the rule does not consider the criticality of the units and the potential that a facility wide shutdown of manufacturing operations may be necessary to install controls.

Commenter (0362) states many of the industrial, commercial, and institutional boilers in the non-EGU sector are "load following" boilers, meaning that the operation of the boiler is dictated by the thermal demands of end-use processes, including demands for steam and/or high temperature hot water that are often weather dependent. The EPA's assumption of consistent emissions rate over the year is incorrect.

Response:

The EPA notes that the $7,500 marginal cost/ton threshold reflected in the analytical framework in the non-EGU screening assessment was a relative 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.

The EPA further addresses the topics in these comments in Section 2.2 (Non-EGU Industry Screening Methodology) and Section 2.3 (Application of the Final Rule to EGU and Non-EGU Sources) and in Section V and Section VI.A and VI.C of the preamble. See also the Final Non-EGU Sectors TSD and final rule Non-EGU Technical Memorandum.

Comments:

Commenter (0416) states the EPA has wrongly concluded that this rule would result in any meaningful improvement in air quality and the rule ignores prior RACT and BACT determinations for the iron and steel sector.

Commenter (0418) states the proposed rule would impose a NO_X emissions limitation of 4.0 lb per ton of glass produced at affected container glass manufacturing furnaces with the PTE 100 tons of NO_X per year or more. Based on vendor-supplied, site-specific cost data, the commenter states the costs will be higher for its two furnaces. The commenter (0418) also states the EPA's economic impact analysis for the proposed FIP for New York omits any consideration of the costs of achieving compliance with the proposed rule at the Elmira facility. This omission is significant; the EPA's impact analysis for the proposed FIP for New York is deficient and does not support adoption of the proposed rule. In addition, the commenter states the EPA's analysis does not demonstrate that NO_X emissions reductions at container glass manufacturing furnaces in Minnesota, New York, or Oklahoma are necessary to achieve attainment with the National Ambient Air Quality Standard for ozone in any downwind county.

Commenter (0437) states the EPA should consider the GHG emissions increases resulting from the proposed rule and defer controls for pulp and paper boilers to determine if further reductions are needed before making them mandatory. The commenter (0437) notes pulp and paper boilers make up a small portion of total NO_X emissions and the cost is very high.

Commenter (0501) states that the EPA has vastly underestimated the number of engines in the pipeline transportation of natural gas sector that would be subject to the proposed rule. Based on data from its members of the population of engines in this industry, the commenter estimated that nearly three times more engines would be affected by the proposed rule than estimated by the EPA (roughly 1,200 engines vs. the EPA's count of 307) and an estimate of the NO_X emissions reduction was more than double EPA's estimate. The commenter notes that the utilization rates used by the EPA are not representative of most engines in this industry. For example, in a more detailed analysis or gas transmission RICE units in Louisiana and Pennsylvania, the commenter found average utilization rates of 23 percent and 34 percent, respectively. Based on the cost of applying retrofit controls to units in these two states, the commenter estimates a total capital cost of $3 billion or more for RICE units affected by the proposed rule and operated by its members in all affected states. Based on the commenter's analysis, the commenter believes the proposed rule is so flawed that the EPA must withdraw or substantially revise the proposal. Finally, the commenter states the EPA has inappropriately identified SCR as the preferred technology for four-stroke lean burn engines and that instead it should be low emissions combustion (LEC) technology.

Commenter (0507) states the EPA should evaluate and include in the case-by-case process an extended path for replacing existing affected non-EGU units rather than installing pollution control.

Commenter (0516) states it would be arbitrary and economically and energy inefficient to require wet kilns to be retrofitted as preheater/precalciner kilns. Retrofitting wet kilns to preheater/precalciner kilns is not possible, an entirely new kiln line would need to be constructed.

Response:

The EPA agrees with commenter that undertaking kiln conversion would necessitate site specific technical evaluation and review and calls for significant capital investment to install new kilns (*i.e.*, preheater/precalciner type). The EPA finds that as long as a source is meeting applicable NO_X emissions limits in the final rule for long wet kilns, this final rule will achieve emissions reductions necessary to eliminate significant contribution. Therefore, the EPA is not finalizing any requirements to mandate the conversion of wet kilns.

4.4.3 Responses to Request for Comments on Non-EGU Control Strategies and Measures

Comments:

Commenter (0243) states NSPS Db requires applicable boilers to comply with an emissions limit for NO_X. To avoid over-regulating boilers that are already subject to requirements that minimize NO_X emissions, the EPA should consider adding regulatory overlap language to allow compliance with these existing rules to show compliance with this rule. The commenter suggests non-EGU boilers with a rate heat capacity of 100,000 BTU/hr or more that are subject to NO_X emissions limitations in the NSPS in 40 CFR 60 may comply with the applicable part 60 rule to demonstrate compliance with this rule.

Commenter (0299) states, in response to "comment whether it is feasible or appropriate to phase out and retire existing long wet kilns in the affected states and to replace them with more energy efficient and less emitting units like preheater/precalciner installations.", if the long wet kilns at Paulding were replaced, the existing production capacity would not be the capacity of the new kiln as a much higher production plant would be needed in order for the project to be economically viable. On a cost per incremental ton removed, a new kiln is infeasible and greatly exceeds the $7,500 threshold set by the EPA in this rulemaking.

Response:

As stated elsewhere in this document undertaking kiln conversion would not only necessitate site specific technical evaluation and review, it would also call for significant capital investment to install new kilns (*i.e.*, preheater/precalciner type). The EPA finds that as long as a source is meeting the applicable NO_X emissions limits in the final rule for long wet kilns, this final rule will achieve emissions reductions necessary to eliminate significant contribution. Therefore, the EPA is not finalizing any requirements to mandate the conversion of wet kilns at this time.

Comments:

Commenter (0304) requests that solid waste incineration units (resource recovery) remain exempt from this proposed FIP. Resource recovery facilities typically generate less than 25 MW and represent less than 1 percent of Minnesota's NO_X emissions. The greatest value provided by resource recovery facilities is reduction in toxicity and volume of solid waste.

Commenter (0323) states the EPA has correctly identified several significant mitigation sources that need to be addressed in this rule – effectively resolving nonattainment in certain areas. The commenter also notes the significance of the emissions from MWC and their impact on the monitors makes these sources candidates for the imposition of new controls by the next applicable attainment date of 2023. Failure to require emissions controls by 2023 on these sources further shifts emissions reductions obligation to the upwind states. Finally, the commenter urges the EPA to consider utilizing the proposed FIP as the opportunity to address new mitigation measures for distributed generation (DG) units.

Response:

The EPA is finalizing requirements for MWCs in this rulemaking as described in Section VI.C.6 of the preamble.

Comment:

Commenter (0347) states the EPA has no reasonable or justifiable basis to require wet-to-dry kiln conversion as part of a good neighbor FIP. If the EPA decides to proceed any further with a wet-to- dry kiln conversion requirement, the EPA must issue a new or supplemental proposal that includes any and all information and data the EPA believes would support such a severe requirement, including the potential impact on companies with wet kilns and the impact on small businesses.

Response:

As stated elsewhere in this document undertaking kiln conversion would necessitate site specific technical evaluation and review, and call for significant capital investment to install new kilns (*i.e.*, preheater/precalciner type). Although the EPA does not consider a cement manufacturing plant with wet kilns a small business, the EPA finds that as long as a source is meeting applicable NO_X emissions limits in the final rule for long wet kilns, this final rule will achieve emissions reductions necessary to eliminate significant contribution. The EPA is not finalizing any requirements to mandate the conversion of wet kilns at this time.

Comments:

Commenter (0353) states proper combustion design is best implemented by the manufacturer, not through add-on controls or engine rebuilds by the operator. This combustion design would be maintained permanently, not just during ozone season. Once installed, these systems cannot be practically uninstalled or go unused after ozone season ends.

Commenter (0362) supports the inclusion of provisions in a final rule that allow the source owners flexibility in assessing the type of monitoring to be used to demonstrate compliance with the emissions limits. The commenter also encourages the EPA to include flexibilities that allow states to promulgate rules (in their implementation of this FIP should it be promulgated) that provide options for affected sources to ensure a seamless integration with existing emissions monitoring requirements that may apply. The commenter also advises, from the time of initial contract, the installation of a new CEMs system will take 22-24 weeks in light of current constraints in the supply chain, up from 16 weeks prior to the pandemic, and for a simple CEMs installation, the cost can range from $140,000 - $235,000, but there are numerous factors that can influence this cost, such as the need for conditioned space to house the instrument analyzers.

Commenter (0371) states, regarding the implementation of SCR, that emissions upgrade updates can be completed on-site, minimizing downtime for the overall operation of the facility. Upgrades are mostly economically completed in conjunction with regularly scheduled major overhaul service intervals. Service intervals vary by make and model with standard or average major overhauls occurring anywhere between 48 – 60 months.

Commenter (0374) provides responses to specific questions regarding emissions rates, control technologies, cost-effectiveness, special considerations for MWC, implementation timeline for MWC, and relationship to NSPS on testing, monitoring, recordkeeping, and reporting for MWC.

Response:

Section VI.C of the preamble and the Final Non-EGU Sectors TSD provide the EPA's rationale for establishing the emissions limits and related compliance requirements for non-EGU industries in this final rule, including requirements for MWCs.

Comments:

Commenter (0377) urges the EPA not to require conversion to all-electric melters, which is not currently technologically feasible in many instances, but the EPA should encourage use of all-electric melters by explicitly exempting them from the definition of "glass melting furnace". The commenter also urges the EPA to provide an incentive for such conversion by expressly exempting all-electric melters from applicability.

Commenter (0379) urges the EPA to require the covered industry sources to economically install, modify, or adapt these established/standard technologies and optimally operate them starting in the next (2023) ozone season, given that this is already long overdue.

Commenter (0403) states it will run the emissions controls on our non-EGU equipment (RICE compressors) year-round because our controls are passive (rather than a catalyst) and we are not able to turn them off. The commenter estimates for installing SCR is $17 million per engine with cost effectiveness over $100,000/ton. Also, on lower emissions limit with layered combustion alone, the commenter states that being able to achieve a NO_X emissions limit lower than 3.0 g/BHP-hr is very much dependent on the equipment make/model and site conditions. Achieving less than 3.0 g/BHP-hr on many 2-stroke lean-burn engines require equipment and controls beyond the basic combustion modifications, most notably larger intercoolers, and associated cooling water towers.

Commenter (0406) states it is not appropriate at this time to require replacement of existing glass manufacturing furnaces with all-electric melter furnaces for a variety of reasons. These reasons include, electric reliability and the risk of molten glass becoming solid within a furnace during a power outage such that it would need to be physically removed from the furnace and the furnace refractory replaced, limitations on size of all-electric melter furnaces, limitations on the ability to quickly change glass pull rates for all-electric melter furnaces, limitations on the amount of recycled glass (cullet) that can be used in all-electric melter furnaces, and challenges with producing amber and other colored glass using all-electric melter furnaces.

Commenters (0545, 0548) oppose any electric glass melter furnace requirements or mandates. One of the most significant issues with 100 percent electric glass melting furnaces is that in many areas the reliability of the electric grid is low, making reliance solely on electricity to power a furnace is a very high-risk proposition for the glass container industry. Most furnaces currently in use in the glass container industry today employ some amount of electric boost, in which electric current is passed through the molten glass, supplying a portion of the energy demand of the furnace. For glass furnaces with gas burners in addition to electric boost, the reliability of the electric grid is much less of a concern, since in the event of electric power failure furnace energy needs can be met by simply increasing natural gas usage during a power failure. Further, from a sustainability standpoint, a low environmental impact is maintained only if the furnace can receive power from renewable energy sources; it is important to understand that it is cleaner to burn fossil fuels in furnaces than to use them to generate electricity.

Commenter (0549) states the EPA should expressly include PEMS an acceptable alternative for CEMS to satisfy 40 CFR 52.45I Monitoring Requirements.

Commenter (0505) states, regarding whether to replace existing glass manufacturing furnaces with all-electric melter installations, that the EPA should consider the infrastructure, electric grid accessibility and reliability, and amount of production time lost during the switch to all electric units in its review of cost-effectiveness for this potential control. Furnaces that are not currently meeting the proposed the EPA NO_X emissions limits may be able to achieve these limits by installing controls on existing furnaces rather than wholesale replacing the furnace.

Commenter (0758) provides the following responses to specific requests for comments:

1. EPA should prioritize a 24-hr NO_X limit and set this 24-hr limit at 50 ppm.
2. EPA should set emissions limits based on assumed installation of SCR technology. SCR is widely used in the industrial sector and currently installed at the Palm Beach Renewable Energy Facility to meet a 50 ppm NO_X emissions limit.
3. There is no justification for failing to set limits for large MWCs that are at least as strong as the limits of 110 ppm on a 24-hr average and 105 ppm on a 30-day average that are identified in the OTC report so long as the operators of individual facilities are given the opportunity to submit facility-specific information demonstrating that a particular MWC is unable to meet the limit. The commenter urges EPA to request more information from the industry on costs.
4. MWC operators should be allowed to submit facility-specific information demonstrating that a particular MWC cannot meet the new limits at or below the cost-effectiveness threshold in EPA's final rule.
5. Babcock Power study suggests the following retrofit schedules from the start of engineering through commissioning and shows that retrofit of MWC emissions controls would not take longer to implement than the 2026 ozone season.
6. All large MWCs are already required to use continuous emissions monitoring systems (CEMS) to demonstrate compliance with NO_X limits. This is another reason that the EPA should require NO_X reductions from this sector in the final rule.

Response:

Section VI.C of the preamble and the Final Non-EGU Sectors TSD provide the EPA's rationale for establishing the emissions limits and related compliance requirements for non-EGU industries in this final rule, including requirements for MWCs. The final rule does not contain any requirement to replace existing glass melting furnaces with all-electric furnaces.

Comments:

Commenter (0764) states the EPA must clearly identify which sources it proposes to regulate rather than leaving states and industry to guess. Regarding the inclusion of EGUs less than or equal to 25 MW, solid waste incineration units, cogeneration units, and lime and gypsum manufacturing sources, the commenter states that any inclusion of these sources in a final rule would (a) violate public comment requirements and (b) would require reanalysis of overcontrol, since including such units without adjusting the required control limits at other covered facilities logically could result in overcontrol. The commenter agrees with the EPA's conclusion that neither lime and gypsum product manufacturing (NAICS code 3274xx) nor metal ore mining (NAICS code 2122xx) should be subject to this rule.

Response:

As explained in Section VI.B and Section VI.C of the preamble, the final rule contains applicability provisions that clearly identify the sources that are subject to the final rule. We respond to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluating potential emissions reductions from these industries, and evaluating related control costs in Section 2.2 (Non-EGU Industry Screening Methodology) and we respond to comments about application of the final rule to EGUs less than 25 MW in Section 2.3 (Application of the Final Rule to EGU and Non-EGU Sources). We respond to comments about potential overcontrol in Section 1.9 (Overcontrol claims) and Section V.D.4 of the preamble.

Comment:

Commenter (0798) states, in response to whether controls will be run on an annual basis, that facilities will only run post-combustion NO_X controls during the ozone season when required to and will otherwise limit their use due to the high O&M cost associated with operation of the SCR, and to attempt to extend the life of the catalyst given the high cost of replacing the catalyst and how quickly the catalyst can be deactivated under the process characteristics of metal furnaces. Low NO_X burners, the other hand, would be operated on a year-round basis since they are integrated into the combustion process.

Response:

Many of the emissions limits for non-EGUs in the final rule can be met through installation and operation of low-NOx burners. For Iron & Steel and Ferroalloy Manufacturing facilities, in particular, the EPA is finalizing a test-and-set requirement for reheat furnaces that requires the installation of low-NOx burners or equivalent low-NO_X technology. For boilers at Iron & Steel and Ferroalloy Manufacturing facilities, the emissions limits in the final rule can be met through installation and operation of: 1) SCR for coal-fired boilers; 2) SCR for residual oil-fired boilers; 3) SCR for distillate oil-fired boilers; and low-NO_X burners and flue gas recirculation for natural gas-fired boilers. The EPA understands that facilities installing SCR on boilers to comply with the final rule may not operate these controls outside the ozone season. That is permissible under the final rule, because the emissions limits in the final rule apply only during the ozone season.

4.5 Over-Control Analysis

4.5.1 General Comments

Comments:

Commenters (0221, 0501, 0764) state that the proposed rule over-controls upwind states. Commenter (0554) concurs that it "goes too far."

Response:

See preamble Section V.D and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for the EPA's overcontrol analysis, where the EPA demonstrates that the rule does not overcontrol any states that are included in the rule.

Comment:

Commenter (0524) states that the proposed rule will result in overcontrol of EGUs. According to the commenter, the proposal does not identify future years' emissions budgets and, therefore, does not identify the significant contribution of each upwind state to downwind nonattainment or maintenance problems. The commenter indicates that the EPA's analysis appears to adhere to the traditional CSAPR approach of relying on NO_X budgets to identify each state's significant contribution, but deviates in key respects from previous versions of EPA's interstate trading rules by taking a different emissions control-based approach. The commenter recommends that the EPA follow its previously established approach to address the interstate transport issues with respect to the 2015 ozone NAAQS.

Response:

See preamble Section V.D.4 for a discussion why dynamic budgets do not constitute overcontrol**.**

4.5.2 EPA Must Prove Reductions Are Necessary

Comments:

Commenters (0306, 0372, 0500, 0513, 0547, 0550, 0551, 0764) overall stress the EPA must prove reductions are necessary in the over-control analysis for each individual industry.

Commenters (0306, 0372, 0550, 0551) state the EPA has not measured or identified significant contribution in the proposed rule. The EPA's analysis instead unfortunately creates confusion. On the one hand, the EPA appears to adhere to its traditional CSAPR approach of relying on mass-based NO_X budgets to identify each state's significant contribution to downwind nonattainment or maintenance problems. On the other, the EPA introduces new findings that would take a very different emissions control-based approach. The commenters are certain either approach, under the current proposed regulatory language, will create over-control problems, but those problems can be addressed by adhering more closely to the practices the EPA established in previous versions of CSAPR. Commenter (0550) adds rather than adopt a flexible trading program as it has done in the past, the EPA proposes to adopt a direct control strategy, unwed to downwind air quality impacts. The EPA continues to rely on its same justifications from its prior rulemakings; however, those are inapplicable here. The commenters believe the EPA's proposed approach results in unlawful overcontrol and should not be finalized.

Response:

In Section V of the preamble, the EPA describes the EGU and non-EGU sectors and sources that are included in the rule. The EPA describes the Step 4 implementation process for EGUs and non-EGUs in Section VI of the preamble.

Comment:

Commenter (0500) states the EPA has previously relied on its cost-effectiveness approach to define "significant" contributions to nonattainment and maintenance. However, instead of implying that the EPA should simply "do it again," the EPA should evaluate the current propriety and effectiveness of applying the same methodology anew. Interstate ozone transport and the impact of upwind NO_X on downwind attainment has changed since the EPA first adopted its 4-step interstate transport framework methodology. The commenter states the EPA is therefore obligated to determine whether simply repeating this approach is the best choice for assessing and implementing the good neighbor obligations under the 2015 Ozone NAAQS. The commenter believes this is particularly important given that the uncontroverted impact of the proposed rule's emissions reductions on ozone NAAQS design values is vanishingly small. Moreover, this analysis should emphasize the costs and benefits related only to ozone concentrations, not PM or climate or other "co- benefits" that are not part of the "good neighbor" obligation. Commenter (0500) notes the EPA appears to recognize this obligation but does not justify its conclusion. Certainly, as applied to sources in Alabama and Mississippi, the identified benefits to air quality in Texas do not justify the imposition of perpetual and compounding regulatory burdens and cost to customers.

Response:

As described in Section V.A of the preamble the EPA consistently applies the Transport framework, then based on the multi-factor test identifies the level of stringency necessary to eliminate significant contribution and interference with maintenance. With respect to emissions reductions for Alabama and Mississippi, Section I of the preamble discusses how the significant contribution and interference with maintenance for these states is addressed. The EPA disagrees that the effects of this rule are "vanishingly small" or "not meaningful". As described in Section V.D of the preamble, there are meaningful improvements in ozone levels at the identified receptors under the emissions control strategy of the final rule to eliminate significant contribution. For many receptors, this rule alone will make substantial progress toward achieving attainment (as further discussed in the Air Quality Modeling Final Rule TSD and the Ozone Transport Policy Analysis Final Rule TSD).

Comment:

Commenter (0500) adds, the enhancements are poorly justified. The Proposal states that “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.” The commenter adds, still, the EPA only cites anecdotal evidence and does not provide modeling data to demonstrate units not operating SCRs or operating SCRs at less than peak efficiency while still complying with allowance surrenders to match emissions are, in fact, causing downwind nonattainment episodes. In the absence of such scientific justification, the EPA should remove the daily emissions rate requirements.

Response:

The trading enhancements are described and justified in preamble Sections V and VI of the preamble. Those sections discuss a variety of sources of evidence of degradation in EGU emissions performance over time under prior trading programs.

Comment:

Commenter (0513) states the EPA acknowledges that it is separately analyzing EGU and non-EGU emissions reductions necessary for attainment in 2026: “EPA examines EGUs and non-EGUs in this section on consistent but distinct, parallel tracks due to differences stemming from the unique characteristics of the power sector compared to other industrial source categories” In conducting this analysis, the EPA concludes that, in 2026, the appropriate significant reduction cost thresholds are $11,000/ton for EGUs and $7,500/ton for non-EGUs. The commenter notes while courts have upheld the EPA’s reliance on a uniform cost threshold as a proxy for eliminating significant contributions, the EPA has never attempted to apply this approach across parallel programs that will simultaneously work to eliminate significant contributions in different industry sectors. The commenter finds, rather than considering the combined effects of emissions reduction measures under the EPA’s chosen cost thresholds, the EPA simply requires all “available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels,” based on its assessment that “these emissions reductions will make a meaningful improvement in air quality.”

Response:

In preamble Section V.D, the EPA describes its approach for EGUs and non-EGUs. In the Ozone Transport Policy Analysis Final Rule TSD (Section C.3 and Appendix H, the EPA describes analyses examining the order of EGU and non-EGU emissions reductions, concluding that the order of imposition of these controls does not affect the EPA’s conclusions about the definition of the emissions reductions that constitute significant contribution.

Comments:

Commenter (0547) adds the EPA’s over-control assessment focuses entirely on EGU emissions reductions but overestimates their contribution and fails to assess whether such reductions are needed in light of the non-EGU reductions. The commenter states the contribution from Wyoming EGUs at the linked Colorado monitor is only 0.07 ppb. Even elimination of all NO_X emissions from the Wyoming EGUs will have very little impact at a massive cost. The commenter notes the EPA recognizes that implementation of both EGU and non-EGU reductions results in over-control based on its standard analysis. See 87 Fed. Reg. at 20,099. Specifically, the EPA determined that the over-control could be avoided by not requiring any non-EGU reductions as it found that the Douglas County monitor achieved attainment and maintenance after full application of EGU reductions in Wyoming and Colorado. Id. Nonetheless, the EPA proposes full implementation. Id. The commenter argues the EPA doesn't address whether full application of the non-EGU reductions has the same impact as full application of the EGU reductions. Commenter (0547) requests that the EPA complete and discuss this analysis.

Response:

The EPA is 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.

Comment:

Commenter (0551) states the over-control analysis assesses over-control as if the proposed rule were a traditional CSAPR-type rulemaking: one that established fixed budgets to address significant contribution based on an assessment of cost-effective controls considered at the fleet as it is projected to look at the time of compliance. The commenters argue the analysis does not attempt to address the impact of the four enhancements, the changes to the generation fleet over time, and how those aspects of the proposed rule will work together. At the very least, an over-control analysis designed to evaluate the effects of the four enhancements would have to compare the emissions reductions expected under the proposed rule beyond 2026, with application of the four enhancements considered, to an appropriate measure of significant contribution. The commenter argues because the EPA's analysis does not do that, the proposed rule has not been adequately evaluated for over-control.

Response:

See preamble Section III for responsive information to this comment. In preamble Sections III.B and V.D.4, the EPA discusses the relationship between the trading program enhancements and the overcontrol assessment.

Comments:

Commenter (0764) references the EPA stating that "future ozone concentrations may also be affected by climate change." This hedge against an uncertain future of potential ozone concentration increases (due to climate change or otherwise) is unlawful. The commenter might as well be planning for a future, lower ozone standard. Moreover, accepting a general relationship between climate change and ground-level ozone does not create a particular link between Houston and Tier 2 sources in Arkansas (and Mississippi) – and thus cannot be a "just in case" rationale for overcontrol. Said another way – concerns about ozone worsening with climate change does not create an exception to the law's mandates regarding overcontrol.

Response:

See preamble Section V.D.4 and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for the EPA's overcontrol analysis, where EPA demonstrates that the rule does not overcontrol any states that are included in the rule. This overcontrol assessment is made, contrary to commenters suggestion, absent any additional effect of climate change on ozone concentrations. However, as described in Section III.A of the preamble, the EPA notes that future ozone concentrations may be affected by climate change and in Section V.D.4 we acknowledge elements of uncertainty that are inherent in our projections that certain receptors will reach attainment, including the ozone-exacerbating effects of climate change.

4.5.3 Use of Outdated and Inaccurate Data – Number of Affected Units

Comments:

Commenters (0306, 0320, 0350, 0359, 0396, 0398, 0409, 0437, 0500, 0501), at large, believe the EPA uses outdated inaccurate data. When proper data is used, the EPA will find the proposed rule overcontrols industries. More specifically, the commenters argue 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 magnitude larger than the EPA's estimations.

Commenters (0306, 0398, 0500) note the EPA failed to accurately consider existing emissions controls and applicable non-EGUs in Texas—including cement kilns, various chemical, petroleum, and coal products manufacturing facilities, pulp, paper, and paperboard mills, and iron, steel, and ferroalloy manufacturing sources—so it likely could be overcontrolling the sources it has selected to regulate and inaccurately estimating the impacts to downwind sources. It is clear, however, that the EPA does not understand whether overcontrol exists.

Commenters (0320, 0359, 0437) note in Section VI.4 of the preamble, the EPA presents the analysis the Agency used to conclude that the proposed rule does not constitute over-control. However, the EPA must revise its analysis on the basis that it has not considered the entire scope of the actual emissions reductions required by the proposed rule. As presented in Table VI.D.3-1 of the preamble, the EPA conducted its overcontrol analysis assuming 6,033 tpy of NO_X emissions reductions from Tier 2 boilers. A review of the file "Tier 2 Boiler Analysis all NAICS Units EPA-HQ-OAR-2021-0668-0225_content.xlsx" reveals that these emissions reductions are attributable to 52 boilers identified by the EPA in its impacts analyses. But, in the same workbook, the EPA identifies 148 boilers potentially subject to the proposed rule on the worksheet titled "Tier 2 Boilers - Contributions" The commenters believe the EPA did not analyze impacts and emissions reductions from 96 boilers because either available controls for the boiler did not meet a pre-determined cost-effectiveness criteria, or because the potential impacts from the boilers at downwind receptors did not meet certain thresholds. Thus, the EPA excluded a certain group of boilers from its impacts analysis, but did not exclude these same boilers from being subject to the proposed standard. The commenters argue the underlying analysis does not match the regulatory applicability language.

Commenter (0350) specifies, the EPA estimates that there are 307 total engines in the Pipeline Transportation of Natural Gas sector affected by the rule, only 77 (and really only 57 of those listed by the 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 the EPA did not count or consider Engines operating in the gathering and boosting or processing segments, further undermining the EPA's analysis. The commenter adds, emissions controls would necessarily operate year-round rather than only during the ozone season, 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 the EPA has assumed. The commenter states while the EPA is permitted some "leeway" to over-control in light of the risk of "under-control," the Supreme Court was unequivocal that there were definite limits on the EPA's discretion: "If the 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."

Response:

We respond to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluating potential emissions reductions from these industries, and evaluating related control costs in Section 2.2 (Non-EGU Industry Screening Methodology). We respond to comments about potential overcontrol in Section 1.9 (Overcontrol claims) and Section V.D.4 of the preamble.

The EPA updated its emissions inventories, updated its air quality modeling, and updated its assessment of emissions reductions availability. As described in preamble Section V.D and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for the EPA's overcontrol analysis, where the EPA demonstrates that the rule (using all the updated data) does not overcontrol any states that are included in the rule.

Comments:

Commenter (0350) adds here, the 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. The commenter believes the EPA's failure to provide this data is arbitrary and capricious, and the EPA cannot rely on other data at a later time to support an adopted rule. 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" the EPA's authority. Pointedly, the EPA has not provided the data necessary to support its proposed rule. Likewise, the EPA's failure to provide data on how it calculated downwind emissions or disclose its emissions reduction targets prevents commenter (0350) and other stakeholders from being able to propose a comparable and reasonable alternative set of emissions thresholds that would not run afoul of the prohibition against over-control.

Response:

The EPA fully documented its Step 3 and overcontrol assessments at proposal (see, e.g., the Ozone Transport Policy Analysis Proposed Rule TSD). The EPA updated its emissions inventories, updated its air quality modeling, and updated its assessment of emissions reductions availability in Section V.D of the preamble and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, where the EPA demonstrates that the rule (using all the updated data) does not overcontrol any states that are included in the rule.

Comments:

Commenters (0396, 0409) note the EPA requests comment on whether to ignore emissions reductions made within downwind states in determining whether an upwind state may be overcontrolled. This concept ignores reality and law. In the real world, downwind states are required by the CAA to reduce emissions to address nonattainment areas that lie within their borders. Failing to account for those legally required reductions would force upwind states to do all of the work needed to improve air quality outside of their jurisdictions, since a full remedy is required by the good neighbor provision. But forcing an upwind state to impose controls that fully remedies downwind air quality problems without any help from the downwind state itself will constitute overcontrol as soon as that downwind state actually reduces emissions as required by law. Therefore, commenter (0396) opposes the EPA's idea of ignoring downwind efforts in evaluating overcontrol of upwind states.

Commenter (0396) states the EPA's only justification for the concept of ignoring downwind emissions reduction efforts is found in a citation to a D.C. Circuit case in a footnote. 87 Fed. Reg. 20099, n.206 (citing Maryland v. EPA, 958 F.3d 1185, 1204 (D.C. Cir. 2020). But Maryland does not say what the EPA suggests. The portion cited by the EPA focused on the timing of emissions reductions, not the scope of them, and it merely rejected the EPA's litigation position that it could rely on downwind states efforts as an excuse to miss the deadlines for attainment in the CAA. The court's decision to hold EPA to those deadlines absent a showing of necessity, notwithstanding expected downwind efforts, is not a command for the EPA to ignore those efforts. Rather, the court merely said that the EPA may not rely solely on downwind efforts to miss its deadlines, an unsurprising result in light of the court's prior precedent in Wisconsin and other cases.

Response:

Section V.D of the preamble describes the EPA's approach at Step 3 to addressing each state's "fair share", with the primary "Step 3" configuration including a reduction from the downwind state. In other words, even if the downwind state is not included in the rule, in the Step 3 configuration that state is assigned a "fair share" of emission reductions of comparable stringency to those applied to the upwind linked states. The EPA also assessed an alternative "full geography" configuration where 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. The EPA finding of no overcontrol was robust to both scenarios (with and without downwind state reductions) See the Ozone Transport Policy Analysis Final Rule TSD for additional details.

Comments:

Commenter (0398) states there are several near-term retirements of coal-fired EGUs that the EPA fails to recognize. Collectively, between Arkansas, Louisiana, Missouri, Oklahoma, and Texas, at least EGU units are expected to retire between 2025 and 2031. These retirements will significantly impact emissions in years past 2026. Therefore, control requirements in the near term after the 2026 ozone season will be more than necessary to eliminate significant contributions from implicated states. Excluding these retirement-related reductions in the Agency's forward-looking analyses equates to more pollution "on the board" than will actually emitted. By overestimating actual emissions in this manner, the EPA is inflating the magnitude of controls and emissions reductions needed to bring linked monitors into attainment, an obvious paradigm of over-control. To compound this by dynamically adjusting budgets downward based on these retirements, further compounds over-control issues. The EPA has no authority under the good neighbor provision of the CAA to require further emissions reductions past the point of re-attainment at problem monitors.

Response:

The EPA's Step 3 and overcontrol findings take into account future retirements in or by the relevant analytic year. As described in preamble Section III and IV, the EPA has established that 2023 and 2026 are the appropriate analytic years. The EPA assess full implementation of Step 3 mitigation measures in its overcontrol analysis for 2026. In preamble Section V.D.4, the EPA discusses the relationship of the trading program enhancements to the overcontrol assessment.

Comments:

Based on commenter's (0437) review of pulp and paper boiler information, commenter (0437) has identified that about 100 fossil fuel-fired boilers would potentially be subject to the proposed standards (assuming biomass boilers are not covered), with 48 fossil fuel-fired boilers likely to need controls (many of which the EPA did not include in its analysis). The analysis also indicates that no controls sufficient to meet the proposed emissions limits are available for the impacted boilers at an ozone season cost effectiveness of $7,500/ton or less, and if the EPA used its own recently updated OAQPS Control Cost Manual methodologies for SCR, its analysis would show this same outcome as well. The EPA's over-control analysis is therefore invalid because it does not consider all the costs and air quality improvements of the proposed rule. Commenter (0437) recommends that the EPA re-evaluate both the impacts of the proposed rule and whether or not the Agency's proposal constitutes over-control by considering the impacts and emissions reductions for all non-EGU boilers potentially subject to the proposed emissions limits.

Commenter (0501) states the EPA's proposed rule would require significantly more emissions reductions on a national and a state-by-state basis than the Agency has assumed. On a national basis, the EPA has calculated that its proposed rule would result in 55,546 TPY of NO_X reductions from the pipeline transportation of natural gas sector. Commenter (0501)'s analysis shows that the proposed rule would result in NO_X reductions of at least approximately 112,967

TPY. The EPA's national NO_X reduction estimate is, therefore, off by at least an approximate 57,421 TPY. If the EPA believes, as it must, that national NO_X emissions 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.

Commenter (0501) argues the state-by-state estimates 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 Interstate Natural Gas Association of America (INGAA) members. Commenter (0501) has therefore not further evaluated them. Of the remaining 19 states, commenter (0501)'s analysis shows that 16 would be subjected to NO_X emissions reductions that are higher—in many cases substantially higher—than the EPA has estimated the proposed rule would require. It is worth noting that three states—Missouri, Oklahoma, and Pennsylvania—are expected to achieve fewer emissions reductions than the EPA has projected. INGAA's analysis shows the EPA has estimated reduction overages of 37, 29, and 45 percent, respectively, which 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. 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 the EPA's pervasive misunderstanding of the fundamental attributes of the natural gas pipeline transportation sector.

Response:

The EPA fully documented its Step 3 and overcontrol assessments at proposal (see, e.g., the Ozone Transport Policy Analysis Proposed Rule TSD). The EPA updated its emissions inventories, updated its photochemical air quality modeling, and updated its assessment of emissions reductions availability for both EGUs and non-EGUs as described in Section V.D of the preamble and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, where the EPA demonstrates that the rule (using all the updated data) does not overcontrol any states that are included in the rule.

In addition, the commenter did not provide details or documentation supporting the statement that the proposed rule would result in NO_X reductions of more than 100,000 tons nationally from the pipeline transportation of natural gas industry. For the final rule, the EPA included flexibilities for the pipeline transportation of natural gas industry and re-estimated emissions reductions overall and for that industry.

4.5.4 Overcontrol

4.5.4.1 Beyond Achievable Reductions / Cost-Effectiveness

Comments:

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0372, 0382, 0798) state the EPA proposing RACT with SCR/SNCR technology will force industry closures, which is over-control.

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0798) argue that the proposed FIP is not written to achieve NAAQS compliance or drive greater controls/use of existing controls. The proposal pushes any source beyond any achievable reductions and leaves operators with only one choice: alternative generation. Not only is this beyond the scope of the statute and the EPA's authority, as a practical matter, may not be possible to expand or construct the resources that could fill the void when thermal generation is unavailable. As the nation suffers multiple blackouts this month, contributed in part to the lack of adequate, available generation, this rule, if finalized as proposed would only exacerbate the power generation challenges being experienced at this time. This proposal is not merely illegal. It is simply bad judgement.

Commenter (0361) notes not every unit can install or activate SNCR in a way that is cost effective, relative to the actual emissions reductions that the units will experience. Inflated assumptions as to achievable emissions reductions, and underestimated implementation costs have led the EPA to presume that compelling the use of SNCR with no regard for the individual circumstances of the EGU in question will be a cost-effective means of reducing NO_X emissions. This is not always the case. In the commenter's experience, the effectiveness of SNCR system is highly variable depending on the operational characteristics of the unit, and the level and consistency of its load. Units deployed during peak timeframes, such as Indiana Municipal Power Agency's WWVS units, will not see the same emissions reductions as base load generation. The cost effectiveness of the requirement to employ SNCR will be highly variable and is unlikely to meet the EPA expectations in even the most optimistic case.

Commenter (0361) is not alone in its concern, or its understanding that this command-and-control approach will not be cost effective or beneficial to an emissions reduction scheme that is specifically designed to maintain flexibility. Each EGU is unique, and its costs and performance are very specific to its circumstances, age, and operational characteristics. The best means of imposing an emissions control regime over thousands of such units is not through technology-specific dictates, but through a regime that controls for the intended purpose of the rule while maintaining flexibility as to its implementation.

Response:

As described in preamble Section III.B and Section V.B, implementing reduction requirements premised on the installation of cost-effective controls that are being widely implemented by others across the fleet of EGU and non-EGU sources to achieve emissions reductions necessary to eliminate significant contribution is not overcontrol.

Comment:

Commenters (0372, 0798) continue, the model appears to significantly underpredict emissions reductions associated with the proposed rule, by not even attempting to include all facilities subject to the proposed rule or attempting to quantify the actual reductions resulting from the emissions limits in the proposed rule. This is important to correct before issuing a final rule because ignoring emissions reductions resulting from the proposed rule would lead to impermissible overcontrol by setting limits that reduce emissions by far more than the EPA has modeled are necessary to result in attainment (especially with respect to the Brazoria County, Texas receptor). Commenters (0372, 0798) state if the EPA intends to proceed with implementing unit specific control emissions limitations, the EPA must either redo the overcontrol analysis using estimated reduction estimates based on the emissions limits proposed in the proposed rule, and/or the EPA must make the limits less stringent so as to match the statewide emissions reductions modeled to not result in downwind attainment without overcontrol.

Response:

The EPA updated its emissions inventories, updated its photochemical air quality modeling, and updated its assessment of emissions reductions availability for both EGUs and non-EGUs, as described in Section V.D of the preamble and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, where the EPA demonstrates that the rule (using all the updated data) does not overcontrol any states that are included in the rule. See also the EPA's response about the Texas receptors in Section 4.5.7 (Greater Degree of Emissions Reductions Imposed Than Needed).

Comment:

Commenter (0382) states the EPA identified 36 nonattainment and maintenance problems in downwind areas in Kentucky, and this will force Kentucky to reduce its non-EGU NO_X emissions to 2,291 tons, constituting a reduction of 19 percent from its 2019 levels. The EPA proposes that Kentucky reduce its EGU NO_X emissions with SCR by 2,944 tons in the coal steam industry, by 188 tons in the oil/gas steam industry, and by 3,132 tons in the all-steam industry. These reductions are alarmingly steep, given Kentucky's already relatively low levels of NO_X emissions. The commenter states it will constituent overcontrol.

Response:

Eliminating significant contribution, based on the multi-factor test, by itself, does not constitute overcontrol. The EPA's overcontrol assessment, presented in preamble Section V.D does not display overcontrol for Kentucky.

Comment:

Commenter (0518) states that the EPA should revisit the proposed controls on non-EGUs at Step 4 because they may lead to overcontrol of some upwind states.

Response:

The overcontrol assessment is part of Step 3 of the transport framework; the EPA updated the estimated non-EGU emissions reductions for the final rule and used these figures in its final rule overcontrol analysis.

4.5.4.2 Overly Stringent Proposed FIP / RACT Limits

Comments:

Commenters (0320, 0334, 0337, 0359, 0361, 0368, 0798) argue it is unreasonable, unlawful, and inconsistent with both the EPA's past practice and court precedent interpreting the good neighbor provision to subject upwind states to emissions limits that are stricter than the RACT limits imposed in the downwind states. Whatever requirements are placed on upwind industry should not be more stringent than those applicable to industries subject to RACT due to actually being in a nonattainment area; it would be irrational, arbitrary, and capricious, when considering impacts to the same nonattainment or maintenance receptor, to force a source far away to enact stricter limits than a source actually in or next door to the nonattainment area. Such a requirement for commenter (0337) would cost hundreds of millions of dollars and would be catastrophic to the company. It would likewise far-exceed the EPA's authority under the "good neighbor" provisions of the CAA and would render any such action as arbitrary and capricious.

Commenter (0798) states the EPA makes the assertion that the limits imposed by the proposed rule on non-EGUs "generally are intended to be consistent with the scope and stringency of RACT." But this stated goal is inconsistent with the approach the EPA actually took to setting the limits, and thus in violation of the EPA's obligation to promulgate internally consistent rules. In fact, for most (but not all) units, the EPA specifically considered RACT limits specified by states, then expressly rejected setting levels consistent with RACT, instead going on to propose limits up to a staggering 50 percent below the corresponding RACT limits considered. These resulting proposed limits are also stricter than BACT, and inconsistent with recent nonselective catalytic reduction (NSCR) BACT evaluations, which the EPA had opportunity to comment on, which have ruled out SCR, NSCR, and other post-EAF NO_X controls as not technically feasible for EAFs. And the limits are even stricter than LAER, given that the EPA can identify no new or existing facility nationwide in the industry that has demonstrated these limits in practice, and has identified no grounds for concluding that they may be feasible on an EAF. Notably, although the EPA claims to identify an annealing furnace that successfully installed an SCR, the EPA does not use that facility as a basis for the emissions limits proposed for Annealing Furnaces, further calling into question whether the limits proposed by the EPA are even possible in practice. And even if some type of annealing furnace ever installed an SCR, the concept of the application of an SCR on all annealing furnaces could not be justified, for instance some of the annealing furnaces at commenter's BRS facility are small units that emit less than 6 tpy and run only intermittently such that they are not even stacked and thus neither CEMS nor SCR would be possible to connect.

Commenter (0798) states the EPA's modeling used to demonstrate statewide emissions reductions necessary to reduce downwind emissions to acceptable levels was not based on the limits included in the proposed rule. Instead, what the EPA actually modeled was as follows: "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 greater than 10 percent more effective than the 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 CE for that control." Notably, the output tables for this modeling show no reductions required at any EAF, and SCR only being added at certain BOF and Blast

Furnaces and boilers. Accordingly, to the extent that the modeling the EPA actually performed shows that good neighbor provisions are satisfied with less stringent emissions reductions, and without any reductions from a single U.S. steel facility, the EPA's choice to nevertheless go further than supported by its modeling and impose the draconian limits more stringent than RACT, BACT, or even LAER necessarily constitutes arbitrary and capricious overcontrol.

Response:

The purpose of the final rule is to satisfy the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I), not RACT requirements, for the 2015 ozone NAAQS. The final rule establishes emissions limits that are generally consistent with the scope and stringency of many RACT rules but that does not mean that the limits established in the final rule are necessarily equivalent to RACT. In setting the emissions limits the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies, and rules or requirements in approved SIP submittals, consent decrees, and permit limits. Based on this review, the EPA identified controls that were widely available and in use at many other similar non-EGU facilities throughout the country, particularly in those areas that have historically struggled or continue to struggle to attain and maintain the 2015 ozone NAAQS. Additional discussion of the EPA's basis for establishing a uniform control level across the covered non-EGU emissions units to address ozone transport in this final rule can be found in Section V.D of the preamble.

In the final rule, the EPA has adjusted the applicability and emissions limits for many non-EGU emissions units in response to information received during public comment. For example, based on information received in public comments on the complex economic and, in some cases, technical challenges associated with implementation of NO_X control technologies on certain emissions units in the Iron and Steel 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. Section VI.C of the preamble and the Final Non-EGU Sectors TSD provide a detailed discussion of the final emissions limits and requirements for all non-EGU industries in the final rule, including changes made to the proposal as a result of information received during the public comment period.

4.5.4.3 Enhancements / Dynamic Budgeting Process

Comments:

Commenter (0533) advocates that the EPA should ensure that upwind states linked only to maintenance areas are not being overcontrolled. The commenter states that beginning with the 2026 ozone season, the EPA's dynamic budgeting approach would result in drastic reductions to the state NO_X budgets by presuming SCR/SNCR retrofits on certain coal, oil and gas-fired units. These substantial NO_X emissions reductions from the EGU sector are not necessary for states that are predicted to be linked only to one or more maintenance receptors in 2026. According to the commenter, nothing in the CAA nor any judicial decision compels the EPA to propose the same remedy for upwind states interfering with maintenance as it does for upwind states contributing to nonattainment. Instead, the commenter believes that, if finalized, the proposed dynamic budgeting approach would result in ongoing reductions in state EGU budgets over time, as budgets are adjusted to account for unit retirements, changes in unit dispatch patterns, and the increasing use of renewables. The commenter concluded that this program element will ensure that EGU sector NO_X emissions continue to decrease over time, thus ensuring that emissions from such states do not interfere with maintenance in any downwind areas and is sufficient to address the good neighbor obligations for these upwind states with regard to downwind maintenance areas. The commenter stated that in the final FIP, the EPA should eliminate the presumed state budget adjustments that correspond to presumed SCR/SNCR retrofits on coal-, oil-, and gas-fired EGUs in any states predicted to be linked only to downwind maintenance receptors in 2026.

Commenters (0317, 0357, 0361, 0366) note the EPA's proposal introduces the new concept of "dynamic" budgets for EGUs, where state budgets would be adjusted for each control period beginning with the 2025 ozone season by applying the control stringency selected by the EPA to updated heat input data measured in the two years prior to the control period. The EPA's authority to "continuously adjust" budgets in this manner also exceeds its statutory authority. If the EPA had the authority to continually change state emissions budgets in such fashion (which they do not), it would have to make each change pursuant to a notice-and-comment rulemaking structure of section 307(D)(1)(B) of the Act. Instead, the EPA proposes within the rule to adjust state emissions budgets each year by administratively issuing a NODA, announcing the state budget for the following ozone season. Thus, as proposed, the rule violates the rulemaking requirements of the CAA.

Commenter (0317) states the proposed FIP identifies six states as linked only to downwind maintenance receptors in 2026: Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin, and Wyoming. Under the proposal, the EPA would, as part of the implementation of the reduced NO_X emissions budgets beginning in 2023/2024 and continuing with dynamic budgeting for 2025 and later, require substantial NO_X emissions reductions from the EGU sector that are not necessary in these states which are predicted to be linked only to one or more maintenance receptors in 2026. This is clear overcontrol.

Commenter (0361) is concerned that if the EPA is permitted to exert the authority to unilaterally recalculate state budgets, the proposed rule does not discuss a mechanism to adjust its overcontrol analysis as state budgets decrease. Failure to consider such adjustments is inconsistent with the clear obligation to ensure that the rule's requirements do not exceed the amount necessary to achieve attainment in the relevant states. An initial overcontrol analysis is not sufficient in the context of a proposed scheme by which the relevant state budget is continually recalculated over time.

Commenters (0361, 0366) argue the cost effectiveness of the program is fundamentally inconsistent with a dynamic budgeting process that is calculated each year through agency action. As interpreted by the Supreme Court, the existing scheme only obligates the elimination of emissions that meet both of the criteria discussed in that opinion. States are not, however, obligated to eliminate emissions that do not fit both criteria. Because of this, any recalculation of the state budget that does not fully account for the satisfaction of these requirements exceeds the scope of the EPA's authority to satisfy the state's good neighbor obligation. The EPA describes a method of recalculating state budgets through "ministerial action.” This unilateral administrative action would, however, be inconsistent with the requirement to engage in notice-and-comment rulemaking under section 307(d). Each budget recalculation would functionally be a new cap and trade scheme. The EPA should engage in the ordinary rulemaking process as it fundamentally changes the market for allowances. Untethered from these processes, stakeholders would have little recourse to address errors—like those material errors in the assumptions and modeling previously discussed herein.

Commenter (0366) gives the example, if a state’s pre-control budget is 1000 tpy and the EPA determines it must reduce emissions by 400 tpy, based on available cost-effect emissions control, the EPA would set the state’s initial emissions budget at 600 tpy. Then, if an affected emissions unit with a heat input allocation equivalent to 40 tpy NO, in the state initial budget shuts down, barring any other changes, the new state budget would be set at 560 tpy. Affected emissions units with minimum emissions control requirements would then need to apply emissions controls, which would have the effect of further lowering the allowable emissions in the state budget in subsequent years. This means that the state achieves beyond 400 tpy of emissions reductions.

Commenter (0551) argues the Agency has not clearly specified significant contribution of the upwind states, as called for in North Carolina. It is possible to rectify this by simply establishing 2026 budgets at this time and clarifying that such budgets resolve significant contribution for the 2015 ozone NAAQS. Alternatively, even if the EPA refrains from establishing numerical 2026 budgets at this time, the proposed rule should at least clarify that the 2026 budgets that would result from the proposed rule’s budget calculation methodology in 2026 would constitute a full remedy and address all significant contribution obligations of upwind states.

Commenter (0551) states the EPA’s argument that the enhancements are needed because of difficulties projecting the future composition of the electric generating fleet is also misplaced because budgets are established to address significant contribution to downwind nonattainment, not to maintain a consistent set of emissions rates from covered sources. Similarly, the EPA’s position that the enhancements are needed because “over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking” fails to recognize—or unreasonably rejects—the premise of an emissions trading program to address interstate transport. Requiring operation of specific emissions controls or achieving strict emissions rate limits at specific sources are methods of emissions control that certain CAA provisions may authorize. But a rule to address significant contribution to downwind nonattainment or maintenance problems cannot be squared with that approach, or at the very least not with the approach contained in the proposed rule. Maintaining operation of emissions controls assumed to be cost-effective under today’s conditions, regardless of future emissions reductions, is not reasonably connected to downwind nonattainment or maintenance. This may be a goal with policy merit, but it is not an endpoint that can be justified under CAA section 110(a)(2)(D)(i)(I).

Commenter (0551) continues, if significant contribution were measured, as in past CSAPR rules, as the amount of emissions eliminated upon meeting the trading program’s goals—here, the 2026 budget—then the enhancements would all work together to require additional reductions beyond that amount. The EPA would impose the enhancements here, however, even though CSAPR trading programs have previously eliminated significant contribution and even though there is no reason to think a similar program will not do so now. This is an obvious case of over-control. As compared against the tons of NO_X reductions that would be required under 2026 budgets, consistent with past practice, the enhancements would require unnecessary reductions and over-control. To the extent the proposed rule identifies emissions reductions based on the four enhancements as necessary to address significant contribution, it has erroneously measured significant contribution without reference to what is necessary to achieve attainment in downwind states. For this reason, the proposed rule is flawed in the same manner as CAIR: it would not "actually require elimination of emissions from sources that contribute significantly and interfere with maintenance in downwind nonattainment areas." Whereas CAIR allowed sources to emit and states to contribute emissions above their significant contribution levels, the proposed rule would require sources and states to cut emissions well below their levels of significant contribution. The proposed rule cannot avoid that result by attempting to define significant contribution in a manner that does not take downwind attainment into account.

Response:

These comments are responded to in Section III, V.D, and VI.B of the preamble.

Comment:

Commenter (0314) states that there is another flaw in \ the way the EPA interprets implementation of the provision. The EPA reasons that if an upwind state is contributing to a downwind state's nonattainment status, the upwind state is to continue reducing its emissions to a point where the downwind state is no longer in nonattainment. The upwind state must reduce its emissions beyond the amount considered significant. This puts an unreasonable burden on upwind states. The EPA should only require an upwind state to reduce its emissions at the level determined to be a significant contribution. Any remaining emissions resulting in nonattainment in a downwind state should be addressed by emissions controls in the downwind state.

Response:

The EPA disagrees that upwind states are required to continue reducing emissions beyond the amount deemed significant, nor does the rule put the burden of reaching attainment on upwind states. See Section III.B and V.D.4 of the preamble.

Comment:

Commenter (0365) advocates that the EPA consider existing emissions reductions programs and controls that are currently in place, noting that Louisiana has an established Title V/part 70 and PSD air permitting program, approved by the EPA. The commenter noted that the program's regulations set forth obligations that industry must follow prior to construction of a major source, and that all permit applications must show that their PTE emissions meet the PSD or NNSR. The commenter stated that, to date, there have been no CAA section 126 actions filed against Louisiana.

Response:

The EPA has considered existing emissions control programs in its modeling at Steps 1 and 2. The absence of a petition under Section 126(b) does not mean a state's sources may not be significantly contributing to violation of the good neighbor provision.

4.5.4.4 Allowance Trading and Generation Shifting

Comments:

Commenters (0354, 0361, 0396, 0409, 0500), at large, believe that allowance trading and generation shifting will result in overcontrol.

Commenters (0354, 0361) state early retirements of many fossil fueled EGUs would result from this proposed FIP and would force a greater shift of electricity generation from thermal generation to renewable sources. The EPA states that in developing the proposed FIP, it quantified and considered the emissions reduction potential from such electricity generation shifting. (87 Fed. Reg. at 20081) Such quantification and incorporation of this electricity generation shift into emissions limitations are illegal because the EPA does not have the authority under the interstate transport provisions to do so or to effectively restructure the electric generating industry through such electricity generation shifting. Commenter (0361) believes the EPA's reliance on generation shifting is an excessive means to attempt to address the clearly defined circumstances outlined by the Supreme Court, and will very likely result in excessive control measures that go beyond what is called for to bring upwind states' contributions within relevant thresholds. The question of whether the EPA has authority to implore plant closures as a part of an emissions-reduction regime has been a contentious one in recent years. The full scope of its authority will likely be affected by litigation pending before the Supreme Court in WV v. EPA, Case Nos. 20-1530, 20-1531, 20-1778 and 20-1780, and if the Court finds that the EPA action encouraging generation shifting is beyond its scope for greenhouse gas emissions, the EPA should take that finding to inform its claimed authority under this proposed rule. Commenter (0361) concurs with petitioners in that case, that regulation affecting generation shifting has the potential to fundamentally alter the electric sector—making it a major question reserved for the federal legislature and outside the scope of administrative action. There are other means by which the EPA can achieve the desired ends of the 2015 NAAQS Rule. Consequently, the administration should reconsider its approach to generation shifting in its proposed rule.

Commenter (0396) argues the EPA's new "constant stringency" approach is likely to result in overcontrol that the EPA has not properly evaluated. Many of the proposed "enhancements" to the CSAPR trading are intended to implement this "constant stringency" approach, which the EPA admits is "an adjustment in its historical approach to eliminating significant contribution." 87 Fed. Reg. at 20095. The EPA's apparent goal with the new approach is to ensure that all covered facilities meet the same level of emissions control, notwithstanding that inconsistent control levels are needed to make allowance trading work. In defense of this new concept, the EPA claims that it is "consistent with the evolution of the Agency's thinking," and that the EPA is not required to focus on “the mass- based reduction in emissions” that its program is expected to achieve.

Commenters (0396, 0500) believe the annual recalibration of budgets by removing allowances to reflect fleet composition changes effectively redefines the amount of contribution every year without determining whether such changes will result in overcontrol. This feature also serves to constrain the number of allowances to the point of inhibiting operation of an effective trading program. The logical outcome of this action is the requirement that every affected unit install and run controls continuously, irrespective of any air quality benefit, or lack thereof, in neighboring states. This proposed annual recalculation of state budgets does not evaluate the emissions reduction needed, if any, to mitigate a state’s significant contribution to affected receptors, nor does it assess the affected receptor’s attainment status.

Commenters (0396, 0500) state the recalibration of banked allowances at the end of each control period has the effect of diminishing the amount of emissions each allowance offsets. This diminishment will further constrain the allowance market and will likely create a shortage of allowances as banking will no longer be a reliable means for capturing value from over-compliance or for mitigating risks from annual variability in actual emissions. Recalibrating banked allowances would undermine the trading program’s primary purpose by prohibiting reliance on the trading market due to unpredictable, constantly changing cost of compliance decisions. The consequence of the likely allowance shortage will be an illiquid market, forcing control devices to operate under a command-and-control construct as if no market exists.

Commenter (0500) adds past trading programs under the CAA have allowed operators to increase the control on some units toto accumulate allowances which can be traded or banked for future use. Because future year operations will not match modeled results exactly, operators need flexibility to manage increases and decreases in emissions related to weather, fuel prices, renewable penetration, demand, and other variables. Authorizing the banking of allowances provides operators the ability to comply with emissions limits while executing a least cost approach to providing reliable electricity throughout multiple ozone seasons. As a backstop, the assurance cap already provides an annual ceiling to ensure the total emissions in any given year are always reasonable.

Commenters (0396, 0500) argue as a result of the EPA’s impounding of allowances, the restricted market for allowances will require units that without this proposed enhancement would have purchased allowances on the open market to now improve controls beyond cost-effective levels or reduce operations. In summary, this proposed enhancement to arbitrarily constrain allowance banking has not been tied to any analysis of air quality improvement or other related metric. Thus, the proposed bank recalibration enhancement is inconsistent with provisions in the CAA and should be removed from the final rule.

Commenter (0409) adds on-the-books-controls should be included for both upwind and downwind states. The timelines for reductions from this proposed rule and home-state reductions to achieve attainment must be concurrent. Commenter (0409) notes the EPA’s model only accounts for reductions based on state budgets. There will be further reductions from the new concepts the EPA introduced through dynamic budgeting, bank recalibrations, retirements caused by this proposed rule, and the daily NO_X limits. This flawed analysis is inconsistent with the EPA's legal obligation to refrain from requiring pollution reductions more than needed to achieve downwind attainment or ensure no interference with maintenance.

Commenter (0500) states the EPA has inserted "enhancements" that are designed to require continuous use of control devices. The Unit-Specific Backstop Daily Emissions Rates, Revised Emissions Budget-Setting Process starting in 2025, and annual Allowance Bank Recalibration are all designed to force continuous operation of control devices, which also serves to constrain unit flexibility. Importantly, the EPA has identified this as an express goal of its Proposal. As a result of these enhancements, the Proposal appears likely to result in emissions reduction requirements that ratchet down over time, achieving greater reductions than the EPA has analyzed or anticipated, particularly since the proposed enhancements are likely to significantly inhibit the development of a viable allowance trading market.

Response:

See preamble Section III.B, V.D, and VI.B.

4.5.4.5 State Specific Examples

Comments:

Commenters (0300, 0326, 0382, 0398, 0398, 0433, 0437, 0519, 0764, 0782), in general, provide state specific examples leading to over-control.

Commenters (0300, 0326, 0437, 0398, 0764) disagree with the EPA's conclusion that non-EGU control requirements for Mississippi, Arkansas and Wyoming don't constitute unnecessary overcontrol. Based on the EPA's own analysis and supporting documentation for this rule, the EPA should find that non-EGU reduction requirements for Arkansas and Mississippi should be limited to only Tier 1 industries, and Wyoming requirements should be limited to only EGU reduction strategies. Requiring controls on Wisconsin pulp and paper mill boilers is another example of over-control. The Chicago area is in the process of being redesignated to attainment for the 2008 ozone NAAQS. Without this redesignation, the area will be bumped up in classification. The EPA published its Chicago area redesignation proposal on March 10, 2022, at 87 Fed. Reg. 13668 and includes this statement in footnote 5 at 87 Fed. Reg. 13679:

> "While modeling is not required, Illinois cited photochemical modeling performed by the EPA and LADCO in support of the interstate transport ''Good Neighbor'' provision of the CAA for the 2015 ozone NAAQS. These modeling results project the highest 2023 average design values to be 0.0662 and 0.0668, well below the 2008 ozone NAAQS. Compared to actual monitored 2009–2013 average design values, both sets of 2023 modeling results show large decreases in ozone concentrations, especially in the heart of the urban area and at the critical monitors at the north of the nonattainment area along the shore of Lake Michigan. These results provide evidence that ozone concentrations will continue to decrease across the entire nonattainment area."

Commenters (0300, 0326, 0398, 0764) state in the FIP that implementation of Tier 2 non-EGU controls may constitute over-control for Arkansas. In fact, the EPA's own modeling shows only a 0.04 ppb reduction at downwind receptors resulting from imposition of Tier 2 non-EGU controls in Arkansas. The last remaining projected nonattainment receptor to which Arkansas is linked (Houston-Bayland Park) is expected to attain the NAAQS after application of EGU and non-EGU Tier 1 controls. The EPA addresses that Tier 2 controls may constitute over-control in Arkansas, as well as Mississippi, as the downwind receptor located in Brazoria County, Texas, is projected to achieve attainment and maintenance after EGU and Tier 1 non-EGU emissions reductions. The EPA then continues to recommend full application of all emissions reduction controls stating that it could otherwise be in nonattainment pending updated emissions inventory and other information. If projected values are trusted to a degree that allows for millions of dollars in expenditures, then such values should also be considered dependable enough to determine that the degree of control is or is not sufficient. In this case, it is clear that Tier 2 controls in Arkansas would constitute over-control. In addition, if Tier 2 controls were to be implemented, the emissions reductions would provide little to no measurable benefit to monitors downwind depending on meteorology: a mere average of 0.04 ppb improvement, per the EPA.

Commenter (0300) notes as EPA notes on page 20098 of the proposed FIP, "For 2 of the 23 states, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.*, Brazoria County, Texas) is estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions." Therefore, regulating numerous Tier 2 industrial boilers in Mississippi would constitute over-control, particularly since the reductions resulting from regulating the Tier 1 categories have not been fully addressed. For example, only a handful of engines in the Pipeline Transportation of Natural Gas industrial sector are evaluated in Mississippi though many more engines would be impacted by the proposed FIP. Also, no NO_X reductions from the Iron and Steel Mills and Ferroalloy Manufacturing industries located in Mississippi are addressed. Lastly, it appears that, of the three Mississippi boilers evaluated, the EPA does not address additional NO_X controls with exception of one boiler (*i.e.*, the Georgia Pacific Monticello natural gas-fired Power Boiler). The EPA's assumed controls of this boiler result in an estimated ozone reduction of 0.0036 ppb at the Brazoria County receptor, an imperceptible reduction that does not warrant regulation of all industrial boilers in the Tier 2 industrial sectors specified in the proposed FIP.

Commenter (0398) adds in the case of Arkansas, Tier 2 controls may constitute over-control. The EPA mentions that "this downwind receptor only resolves by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions.". Commenter (0398) contends that in Arkansas, by the EPA's own reasoning that "small margin" benefits may constitute over-control, controls on EGUs and Tier 1 sources are also over-control on the EPA's part. To the point, at an underestimated total cost of $22 billion nationwide, the EPA predicts only the following meager average air quality benefits to downwind ozone receptors:

Existing EGU controls in 2023 - 0.07 ppb

New EGU controls/Gen. shifting in 2026 - 0.36 ppb

Non-EGU (Tier 1) - 0.18 ppb

Non-EGU (Tier 2) - 0.04 ppb

Total = 0.64 ppb

Furthermore, commenter (0398) states in categorizing EGUs, Tier I non-EGU sources, and Tier II non-EGU sources, the EPA improperly usurps the role of the states under CAA §110. It is the states that are required to make these choices and decisions under the CAA. The EPA's selection and categorization of sources into Tier I and Tier II is improper. Additionally, commenter (0398) maintains that the Arkansas Transport SIP submission is approvable as originally submitted, as it was based on information and guidance available at the time of SIP development, and that the EPA's arbitrary use of a 1 percent threshold (while simultaneously shrugging off previous guidance issued to states regarding flexibility), and the Agency's sudden switch to new modeling and linkages creates a situational over-control. Commenter (0326) argues the EPA's modeling – the only modeling currently available – indicates that the Brazoria County monitor will attain the NAAQS, and it does not matter if the monitor attains by a small margin or a large one— if the monitor shows attainment, then in accordance with EME Homer City, the EPA has no basis to require additional reductions from an upwind state.

In a similar comment, commenter (0782) adds the EPA's Ozone Transport Policy Analysis Proposed Rule TSD suggests application of estimated non-EGU emissions controls from Tier 1 and Tier 2 industries may constitute over-control for Wyoming when including the assumption Colorado's "fair share" of emissions reductions. The commenter argues it is inappropriate and inconsistent with prior CSAPR rulemakings to remove the assumption of commensurate downwind state reductions. Thus, the emissions reductions from the Proposal's EGU requirements are sufficient for Wyoming to satisfy its good neighbor obligations and non-EGU requirements would constitute impermissible over-control.

Commenter (0326) reiterates for Wyoming, the proposed FIP notes a potential over-control finding for Wyoming, because the last downwind receptor for Wyoming (Douglas County, Colorado) is estimated to attain the NAAQS after full application of EGU reductions in Colorado (which is not subject to the proposed FIP). However, when downwind state reductions in Colorado are removed from the methodology, the Douglas County receptor does not resolve and there is no identified over-control estimated for Wyoming. Footnote 200 to the proposed FIP explains the EPA's decision as follows:

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

Response:

See Section I and V.A of the preamble for a general discussion of our Step 3 analysis. Section V.D describes the EPA's approach at Step 3 to addressing each state's "fair share", with the primary configuration including a reduction from the downwind state. Section IV.E of the preamble describes EPA's air quality modeling projecting nonattainment and maintenance receptors. The EPA disagrees that the effects of this rule are "vanishingly small" or "not meaningful" or that the improvements constitute overcontrol. The EPA's overcontrol assessment is described in preamble Section V.D, the Ozone Transport Policy Analysis Final Rule TSD Section C.3 and Section 10.3 (Comments about AQAT) and includes an evaluation of emissions reductions from EGUs and non-EGUs. As described in Section V.D of the preamble, there are meaningful improvements in ozone levels at the identified receptors under the emissions control strategy of the final rule to eliminate significant contribution. For many receptors, this rule alone will make substantial progress toward achieving attainment (as further discussed in the Air Quality Modeling Final Rule TSD and the Ozone Transport Policy Analysis Final Rule TSD). The segment of the comment claiming the downwind benefit does not warrant the upwind emissions reduction requirements is further responded to in Section 4.4 (The EPA's Assessment of Cost, Nitrogen Oxides (NO_X) Reductions, and Air Quality).

We respond to the comments regarding the Chicago-area designation at Section 3.5.3.14 of this document.

Comments:

Commenter (0326) states when the Administrator designates an area as nonattainment with respect to any NAAQS, section 172(b) of the Clean Air Act requires the state to submit a plan or plan revision no later than three years after designation. Section 172(c) of the Act requires such plans to provide for the implementation of all reasonably available control measures as expeditiously as practicable and to provide for attainment of the NAAQS. If attainment on a downwind state depends upon the implementation of controls within the state, then the EPA needs to enforce those requirements rather than shifting the burden to the upwind state(s).

Response:

See preamble Section IV.A and Section 3.1 of this document for response to this comment.

Comments:

Commenter (0382) argues as they pertain to Kentucky's emissions rates, the proposed FIP fails the standards set by EME Homer I and II, and will result in over-control, because Kentucky's linked downwind location "would still attain its NAAQS if . . . [Kentucky] were subject to less stringent emissions limits." The central problem—relevant to all states that fall under the proposed FIP —is that the EPA is not focusing discretely on imposing emissions limits in the "amount necessary to achieve attainment" in downwind states. Rather, the EPA is proposing a regulatory scheme that, according to its own Rule, seeks to further "environmental justice considerations," "maintain environmental rigor," and "promote more consistent operation and optimization of emissions controls." It is worth noting that in the current rule, 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, in turn, elaborates that "fair treatment" "mean[s] 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." Moreover, the proposed questions the EPA outlines to inform its regulatory actions set subjective and imprecise standards to regulate upwind states' emissions, which conflict with the limited scope of the EPA's authority. For example, the EPA outlines its three analytical considerations as:

1. Are there *potential* environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?

2. Are there *potential* environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?

3. For the regulatory option(s) under consideration, are *potential* environmental justice concerns created or mitigated compared to the baseline?

Commenter (0382) continues, rather than analyzing whether particular proposed reductions were directed specifically at "amounts" of emissions that "contribute significantly" to "nonattainment" of NAAQS in the linked downwind locations, the EPA chooses to regulate based on seemingly intangible objectives. Along with the above, these nebulous goalposts include the EPA's forecasted "monetized health benefits," and "annualized monetized climate benefits"—objectives it also claims to be in the greater public interest. Unfortunately, goalposts like these ignore one particularly important public interest: the upwind states' industrial-based economies and the connection those economies have to the long-term prosperity and growth of the American populace. Accordingly, all the regulated upwind states lack transparent gauges to know what emissions standards are "necessary" to avoid contributing to the nonattainment of NAAQS in downwind locations.

Response:

The EPA's overcontrol assessment is described in preamble Section V.D and further addressed in the Ozone Transport Policy Analysis Final Rule TSD Section C.3. See Section III.B and VI.B of the preamble for a description and justification of the "enhancements" to the trading program for EGUs.

Section VII of the preamble discusses the environmental justice analysis of the rule.

Comments:

Commenter (0382) states for ozone-season NO_X , there is no reliable record data showing that Kentucky's linked downwind location would not comply with its NAAQS between 2023 and 2025 absent any Good-Neighbor obligations placed on Kentucky. This means that rather than focusing exclusively on achieving downwind attainment, the EPA is proposing drastic reductions on Kentucky's EGU and non-EGU emissions to a level that is 43 percent less than current standards, which the EPA explains will help "net at least $9.3 billion and could be as high as $18 billion" in "monetized health benefits" by 2026, as well as "$1.5 billion" in "annualized monetized climate benefits," at a total cost for regulated states of only "$1.1 billion." And annually, according to the EPA, the "net monetized health benefits (not including monetized climate benefits) after accounting for the costs of compliance . . . would be $15 billion."

Commenter (0382) continues, but these projected benefits are speculative. Worse, the EPA estimates total costs to regulated states as $1.1 billion without soliciting actual input from the affected upwind states, whose economies will be impacted on multi-generational levels that result in costs that far exceed the EPA's estimates. More so, the EPA fails to explain sufficiently why it is requiring some states to reduce downwind pollution to levels far below the applicable NAAQS. Nor does the EPA assess whether more modest reduction proposals would result in attainment in downwind locations. The EPA's omission of its specific analysis for each downwind location is problematic under EME Homer I and II. In particular, for Kentucky, if lower cost controls—rather than reductions to 2,291 tons in non-EGU NO_X emissions, 2,944 tons in EGU NO_X emissions in the coal steam industry, 188 tons in the oil/gas steam industry, and 3,132 tons in the all-steam industry —would yield downwind NAAQS attainment in Kentucky's linked location, then the EPA's current proposed reductions on the Commonwealth "cannot be necessary to . . . the achievement of attainment" in that linked location. In other words, "requiring [Kentucky] to implement higher cost controls does not produce benefits that are 'incidental' to attainment elsewhere; it produces benefits that are 'unnecessary to downwind attainment anywhere."

Commenter (0382) concludes the EPA's emissions reductions imposed on Kentucky and other states require them to reduce pollutants far beyond the point necessary to achieve downwind attainment in its linked location. Therefore, not only does the proposed FIP violate the Supreme Court's directive in EME Homer I and the D.C. Circuit's directive in EME Homer II, but it also far exceeds the EPA's statutory authority under the CAA's Good-Neighbor provision.

Response:

The EPA's description of how the rule applies to Kentucky can be found in preamble Section I. The EPA's description of the overall approach for the final rule can be found in Section III.B of the preamble. The EPA's assessment of overcontrol for Kentucky and the finding that the rule does not overcontrol emissions from that state can be found in Section V.D. The presentation of the RIA analysis of cost and benefits of the rule are discussed in Section VIII of the preamble. The commenter's assertion that the downwind air quality benefits do not justify the upwind emissions reductions requirements reflects an opinion that is at odds both with the findings of meaningful air quality improvement at Step 3, and prior judicial precedent upholding the Agency's 4-step interstate transport framework as a lawful and appropriate method of defining and eliminating significant contribution.

Comments:

Commenter (0433) states the EPA's proposal does not model attainment at three of Connecticut's critical ozone monitors. While the EPA conducts an over-control analysis for individual states [87 FR 20098] and determines that there may be reason to exclude individual states from certain controls based on those states no longer being linked to nonattainment receptors, the EPA does not then turn its consideration to the implications of under-control. Though the EPA acknowledges it is obliged to consider under-control [87 FR 20055], it conducts no such assessment with respect to contributions to Connecticut's Greenwich, Stratford and Westport monitors that the EPA modeling predicts will remain nonattainment through, and likely beyond, 2026. These three sites are linked to three nearby states in excess of the one-percent threshold the EPA uses to establish linkage to a significant contribution, both before and after consideration of the proposed rule. As such, commenter (0433) believes the EPA is required to further evaluate its proposed rule for under-control.

Response:

See the EPA's description of the final rule approach in preamble Section III.B. The full elimination of significant contribution and interference for all states with regards to overcontrol is described in preamble Section V.

The EPA's assessment of overcontrol for all receptors can be found in preamble Section V.D and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD.

Comment:

Commenter (0437) argues Wisconsin and its pulp and paper mill boilers are included in the proposed 2015 ozone transport rule solely because the EPA asserts they impact the Chicago area monitors. The statement above, although made in the context of the 2008 ozone redesignation, concludes that the EPA and LADCO modeling demonstrate that Chicago area monitors will experience ozone concentrations much lower than the 2015 ozone NAAQS in 2023 and additional reductions are expected thereafter.

Response:

In the final rulemaking, the EPA has updated its emissions inventories and air quality modeling and used that information to specify the receptors to which upwind states significantly contribute and/or interfere with maintenance. As described in preamble Section IV, the EPA is finalizing that Wisconsin is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states for 2023. However, based on updates to both the EPA's emissions inventory and air quality modeling due to commenter input, the EPA's final rule analysis shows no linkage between Wisconsin and downwind receptors in 2026. Therefore, the EPA is not finalizing any additional stringency levels for Wisconsin in 2026 (*i.e.*, no non-EGU mitigation measures or EGU SCR mitigation measures).

Comment:

Commenter (0519) states the EPA has failed to adequately assess the potential for overcontrol in Oklahoma. First, the EPA must consider whether the combined emissions reduction measures for EGUs and non-EGUs under the two prongs of this rule exceed the emissions reductions necessary to achieve attainment in every downwind state. Second, the EPA's daily backstop emissions rate imposes additional emissions reduction requirements that the EPA has not adequately accounted for in its overcontrol analysis. Third, the EPA's dynamic emissions budget and dynamic allowance bank cap will increase required levels of emissions reduction over time, creating a significant risk of overcontrol that the EPA has failed to account for. Without full and proper consideration of these additional factors, the EPA has not reasonably assessed whether the proposed FIP will require Oklahoma to reduce emissions by more than the amount necessary to achieve attainment in every downwind state to which they are linked and bas exceeded its authority under CAA § 110(a)(3)(D)(i)(I).

Response:

See preamble Section V.D and Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD for a description about the assessment of overcontrol with respect to Oklahoma, demonstrating that the level of control does not result in overcontrol.

Finally, as described in Section V.D the trading program enhancements do not result in overcontrol.

Comment:

Commenter (0289) states that the EPA’s control analysis at Step 3 only evaluates emissions reductions from any linked upwind state based on an arbitrary $/ton threshold that the EPA sets. The commenter adds that the EPA gives no more or less weight to an emissions reduction that achieves more ozone reductions at the problem receptors, noting that in some cases, NO_X emissions from upwind states may have little to no impact on the ozone problems in downwind states, especially if those downwind receptors are located in VOC-sensitive areas. The commenter contends that the EPA does not attempt to understand, explain, or consider the circumstances causing the ozone problems in downwind states or how the emissions reductions identified in Step 3 relate to these ozone problems. The commenter adds that the EPA’s approach under Step 3 leads to bizarre outcomes. The commenter relates that Wisconsin is the state where three of the four receptors to which Missouri is linked are located, and under the EPA’s Step 3 analysis, it finds it cost-effective in the year 2023 to permit Wisconsin EGUs to emit more than the business-as-usual case. However, the commenter explains that in Missouri, the EPA’s proposed FIP would require over 8,000 tons of NO_X reductions during the ozone season at a cost of tens of millions of dollars per year. The commenter adds that the EPA states that it applies Step 3 toto be equitable to all states, but when scenarios like this are the outcome, it does not seem equitable. The commenter acknowledges that the good neighbor provision is not intended to control in-state emissions that are contributing to an ozone problem. However, the commenter states that it is astonishing that the EPA does not even consider the obligation of the impacted state itself to apply controls to address its own pollution problems before imposing billions of dollars in control costs on all the upwind states. According to the commenter, the costs imposed on Missouri will amount to billions of dollars over the life of the rule, yet Missouri's highest contribution to a linked receptor in 2026 will only lower from a business-as-usual figure of 1.70 ppb to 0.95 ppb. The commenter remarks that this does not appear to be a cost-effective approach. The commenter requests the EPA to consider the impact to the problem receptors in an updated Step 3 analysis. The commenter states that the EPA could accomplish this by first considering the in-state emissions reductions achievable to address the issue, and then when determining upwind state obligations, the EPA could employ a cost per ppb improvement at the problem receptor in question and identify the requisite amount of total upwind state emissions reductions needed to collectively address the good neighbor obligation. The commenter also notes that states are still linked to downwind nonattainment or maintenance receptors even after imposition of all the control requirements. According to the commenter, this shows a glaring problem with the EPA's process at Step 2 as the states included in the FIP could not have escaped the FIP even if they had written SIPs that controlled emissions to the same level as the FIP because they would have still been linked to problem receptors above 1 percent of the level of the standard. The commenter protests that there is essentially no hope for a state to avoid a good neighbor FIP unless it can unlink itself through new controls at a reevaluation of Step 2. However, the commenter asserts that the EPA does not hold itself to this same standard, which calls into serious question its implementation of Step 2 and Step 3 of the framework it uses to address good neighbor obligations.

Response:

For the EPA's response about the effects of potential VOC and/or NO_X reductions, along with the justification for why the EPA is pursuing NO_X emissions reductions in this rule, see the preamble Section III.A and V.A. As described in Section V.D the EPA describes how in Step 3 the EPA accounts for the downwind state's "fair share" of the problem. With respect to the commenters assertion that there was no way to avoid the FIP, this is incorrect. Getting the state's air quality contributions below the Step 1 and Step 2 thresholds is only one way. The state could have submitted an approvable SIP, and at any time can submit a SIP to replace the final FIP.

4.5.5 The EPA v. EME Homer / Other Court Opinions

Comments:

Commenters (0306, 0317, 0357, 0326, 0350, 0354, 0382, 0396, 0398, 0513, 0541, 0551, 0554), in general, believe that the EPA v. EME Homer City Generation case prohibits the EPA from overcontrolling historically declining ozone concentrations.

Commenters (0306, 0317, 0357, 0326, 0350, 0354, 0382, 0396, 0398, 0513, 0541, 0551, 0554) state the Supreme Court has clearly affirmed that such "overcontrol," reducing state level emissions beyond that which is necessary to achieve attainment in downwind states, is prohibited. EPA v. EME Homer City Generation, L.P., 572 US 489, 492 (2019). In promulgating a good neighbor FIP, the EPA is required to quantify the emissions from a state that impact the downwind states. Once those emissions reductions required by a budget are achieved, the state has met its obligations. The EPA's proposal to continue to ratchet down emissions beyond what is required for states to meet their attainment obligations amounts to an unlawful overcontrol. Indeed, this proposal goes well beyond a “trading program” as typically understood, and rather is a regulatory program that sets emissions limitations and mandates specific required emissions control equipment for EGUs. Regulating existing EGUs in such a manner is beyond the good neighbor provisions in CAA section 110 and, thus, beyond the EPA’s authority. Commenter (0357) recommends that, at a minimum, the EPA delay further work on this rule until the Supreme Court decides West Virginia v. EPA (Sup. Court 20-1530), argued Feb. 28, 2022, to definitively determine EPA’s authority in this regard.

Commenters (0513, 0541) state the EPA’s failure to adequately analyze the combined emissions reductions impacts from EGUs and non-EGUs exceeds its statutory authority under CAA § 110(a)(2)(D) to prohibit “emissions activity within the state” in “amounts which will contribute significantly,” and creates an unreasonable risk that individual covered states will be subject to overcontrol. While the EPA has been afforded significant leeway based on the EPA’s “statutory obligation to avoid ‘under-control,’ *i.e.*, to maximize achievement of attainment downwind,” the risks of overcontrol are exponentially increased by conducting separate assessments of significant contributions for EGUs and non-EGUs. The commenters believe this rule goes well beyond “some amount of overcontrol” that may be considered inevitable from the application of EPA’s cost threshold approach to only the EGU sector. The overcontrol created from EPA’s approach is compounded by creating two distinct but parallel programs for EGUs and non-EGUs, each of which will likely include an amount of overcontrol. It is unreasonable for the EPA to fail to consider whether the cumulative emissions reductions exceed what is authorized by CAA § 110(a)(2)(D). The commenters stress as the D.C. Circuit emphasized, “[t]he Supreme Court made crystal clear in EME Homer that over-attainment in downwind locations is impermissible when that excess attainment is ‘unnecessary.’”

Commenter (0554) argues neither the quote provided by the EPA nor anything else in the court’s opinion offers any basis for assuming home states will do nothing to address their own air quality problems. The quote the EPA offers is selectively plucked out of context from a discussion on timing of attainment deadlines, not whether home state reductions belong in an over-control analysis. The court introduces the quoted section of its opinion, which is entitled “Selection of Year to Measure Air Quality” by stating “[w]e next consider a question of timing.” The specific quote chosen by the EPA comes from a subsection on “future nonattainment,” in which the court rejected an argument from the EPA that it could ignore the initial attainment deadline for “marginal” nonattainment areas because home-state efforts would achieve attainment by the next deadline for “moderate” nonattainment areas. The court rejected that argument because it was directly inconsistent with its recent Wisconsin decision, which requires the EPA to ensure its transport programs consider all attainment deadlines unless it is impossible to do so. In other words, the court did not say the EPA should ignore home-state efforts. Rather, it said that the EPA cannot rely on those efforts to ignore an initial attainment deadline just because those efforts may result in attainment before a later deadline.

Commenter (0554) adds another portion of the court’s opinion actually suggests the EPA should recognize home-state efforts, not ignore them. In discussing states that are part of a multi-state nonattainment area, the court noted that such states have “the concomitant responsibility to limit their own emissions,” even if their in-state monitors show attainment. If the EPA is looking for guidance from the Maryland decision about what assumptions it must use to justify its new transport proposal, it should focus on the court's recognition that home states are responsible for limiting their emissions, not the court's rejection of the EPA's attempt to use that concept to ignore an attainment deadline that Wisconsin required the EPA to meet. In truth, the Maryland decision does not address over-control directly at all. The case involved two petitions from the states of Maryland and Delaware asking the EPA to impose upwind controls, but the EPA denied that petition and refused to impose any new controls. Since the issue in the case was the EPA's failure to impose controls, not a program to impose new controls, the court had no occasion to consider if over-control might occur—there were simply no new controls to consider, and thus no over-control analysis to review. The only time the court even mentioned the phrase "over-control" was in describing the procedural history of the case. In that section, the court recognized the EPA's long-standing policy, not challenged in the case, that over-control could occur if a home state's own efforts would achieve attainment by the first attainment deadline. The court did not reject that policy. Instead, the court simply refused to allow the EPA to rely on home-state efforts to justify ignoring an attainment deadline, which the CAA does not allow, per Wisconsin.

Commenter (0554) argues the EPA must not read more into the Maryland case than what is actually there, and its misinterpretation of the decision does not satisfy the burden it bears under FCC v. Fox TV to justify its departure from its own prior policy. The EPA should instead follow its long-standing practice of recognizing home-state emissions reductions in its over-control analysis. The EPA continued to follow that approach in its 2021 Revised CSAPR Update Rule, even though the EPA issued that proposal and final rule well after the Maryland decision, and the EPA has offered no other basis for reversing course in this proposal.

Response:

In preamble Section III.B, V, and VI.B, the EPA describes the approach for the final rule applying the 4-step transport framework as relevant to these comments. The EPA's assessment of overcontrol for all receptors, where the EPA demonstrates that the rule does not overcontrol any states, can be found in preamble Section V.D and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD. Finally, as described in Section V.D the trading program enhancements do not result in overcontrol. As described in Section V.D, the EPA describes how in Step 3 and in our overcontrol analysis the EPA accounts for the downwind state's "fair share" of the problem. In the Appendix of the Ozone Transport Policy Analysis Final Rule TSD, the EPA examines the effects of the order of EGU vs non-EGU emissions reductions, concluding that the order of controls on these sectors does not affect the EPA's conclusions about overcontrol and the level of stringency needed to eliminate significant contribution and interference with maintenance.

We noted at proposal that *Maryland* seemed to call into question whether it was appropriate to assume some amount of emissions reduction from home states where a receptor is located in evaluating the emissions that constitute significant contribution from an upwind state. We need not resolve that question in this final rule because the final rule analysis demonstrates that even assuming a fair share from the home state, there is no overcontrol. We note that this question would only be relevant as to the receptors in Colorado and Connecticut, which are not themselves upwind states subject to the requirements of this rule.

4.5.6 Proposed FIP, as Written, Does Not Result in Over-Control

Comments:

Commenter (0758) argues the EPA's proposed rule must be more stringent to avoid under-control.

Commenter (0758) argues the EPA correctly proposes to determine that the emissions reduction requirements of the rule do not constitute "overcontrol." Regulation cannot constitute overcontrol when it is necessary to discharge the EPA's central statutory obligation under the good neighbor provision—to eliminate upwind states' contribution to downwind attainment and maintenance problems. And in light of the central statutory objective of attainment and maintenance of the ozone standard, the EPA must resolve significant uncertainty in favor of protecting public health and the environment. All of the pollution reductions the EPA proposes to require are necessary to discharge that statutory obligation, and projections that suggest ozone levels may fall to slightly below the level of the standard in two locations are the product of overly optimistic assumptions that underestimate future emissions. The EPA should correct these projections in the final rule. Furthermore, the Supreme Court has held that some pollution reduction below the level of the standard is permitted under the statute in pursuit of necessary pollution reductions, and any such reductions that resulted from this rule, if they materialized, would fall within that statutory "leeway." EME Homer City, 572 U.S. at 523.

Commenter (0758) states the EPA's central priority in this rulemaking must be the attainment and maintenance of the 2015 ozone standard in affected downwind areas. The good neighbor Provision, 42 C. § 7410(a)(2)(D), requires the EPA to "prohibit[]" sources in upwind states "from emitting any air pollutant in amounts which will contribute significantly to nonattainment ... or interfere with maintenance by ... any other State with respect to" the 2015 ozone standard. Further, the EPA must prohibit this pollution consistent with downwind areas' attainment deadlines, Wisconsin, 938 F.3d at 318; North Carolina, 531 F.3d at 911-13 (quoting 42 U.S.C. § 7410(a)(2)(D)). Thus, the EPA's obligation is to require that states "eliminate their substantial contributions to downwind nonattainment [and their interference with downwind maintenance] in concert with the attainment deadlines." Wisconsin, 938 F.3d at 318. Regulation cannot constitute overcontrol when it is necessary to discharge EPA's statutory obligation under the good neighbor provision.

Commenter (0758) continues, as multiple decisions of the D.C. Circuit and the Supreme Court recognize, Congress enacted the CAA to ensure timely attainment and maintenance of clean air standards. Train v. NRDC, 421 U.S. 60, 64 (1975) (Congress reacted to "disappointing" progress "by taking a stick to the States"); Union Elec. Co. v. EPA, 427 U.S. 246, 256 (1976) (Clean Air Act is "a drastic remedy to ... [the] problem of air pollution"); Whitman v. Am. Trucking Ass'ns, 531 U.S. 484 (2001). In pursuit of that objective, Congress established deadlines that "require[]" attainment and maintenance of the standards "within a specified period of time." Train, 421 U.S. at 64-65. These deadlines for attainment and maintenance of the standards are not only "central to the ... regulatory scheme," Sierra Club v. EPA, 294 F.3d 155, 161 (D.C. Cir. 2002) (quoting Union Elec., 427 U.S. at 258), but constitute the very "heart" of the Act. Train, 421 U.S. at 66- 67. In light of the central statutory objective of prompt attainment and maintenance of the ozone standard, the EPA must resolve significant uncertainty in favor of protecting public health and the environment. To do otherwise would defeat both the letter and the spirit of the CAA.

Commenter (0758) acknowledges although the EPA is also required to avoid unnecessarily overcontrolling emissions, the EPA's approach to overcontrol cannot defeat the central statutory obligation to secure prompt attainment and maintenance of the clean air standards. Sierra Club, 294 F.3d at 161 (rejecting interpretation that "would subvert the purposes of the [Clean Air] Act" by delaying attainment); Motor Vehicle Mfrs. Ass'n of U.S. v. Ruckelshaus, 719 F.2d 1159, 1165 (D.C. Cir. 1983) ("A statute should ordinarily be read to effectuate its purposes rather than to frustrate them."). The EPA should avoid overcontrol of ozone pollution, but "the Agency also has a statutory obligation to avoid 'under-control.'" EME Homer City, 572 U.S. at 523. Yet in prior rulemakings the EPA has frequently under-controlled ozone pollution, leaving ongoing significant contributions to downwind nonattainment, and interference with downwind maintenance, after full implementation of the rules. The EPA projected that the CSAPR Update, for example, would reduce ozone levels by an average of only 0.29 ppb in downwind areas with attainment and maintenance problems, even though many of those areas faced ozone levels many ppb above the 75-ppb standard, due in large part to interstate ozone pollution.

Commenter (0758) argues even the Revised CSAPR Update, which the EPA claimed was a full remedy to interstate ozone issues under the 2008 ozone standard, required measures projected to achieve only 0.17 ppb of average ozone reduction at downwind nonattainment and maintenance receptors, and all of the covered states were projected, after implementation of the rule, to continue to contribute at least one percent of the NAAQS to at least one struggling receptor. 86 Fed. Reg. at 23,107, tbl. VI.D.1, 23,115. Even these projections were overestimates, because they incorporated many of the same overly optimistic projections. In this rule, the EPA must put an end to the pattern of persistent undercontrol of ozone transport and prioritize achievement of its central statutory objective of attainment and maintenance of the ozone standard.

Response:

As described in preamble Section IV, the EPA updated its emissions inventories and air quality modeling. The monitors that the EPA identified as receptors are identified in preamble Section IV.E. In preamble Section III.B, V, and VI.B, EPA describes the approach for the final rule applying the 4-step transport framework to eliminate significant contribution and interference with maintenance. As described in preamble Section IV.A and VI.A, the EPA's action is aligned with the attainment dates for the NAAQS. The EPA's assessment of overcontrol for all receptors, where the EPA demonstrates that the rule does not overcontrol any states, can be found in preamble Section V.D and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD.

4.5.7 Greater Degree of Emission Reductions Imposed Than Needed

Comments:

Commenters (0317, 0354, 0396) state the proposed FIP clearly imposes a greater degree of emissions reductions than are necessary to prevent emissions from contributing significantly to nonattainment. It will require the most monumentally costly controls ever proposed toto achieve nominal reductions in ozone concentration at a monitor (Harris County, Texas) for which there has been no demonstrated evidence to indicate the facilities are actually contributing significantly to nonattainment. Commenter (354) states the proposed FIP is not justified because it is premised on erroneous data and analysis, as described in the Texas Transport Working Group's comments.

Commenter (0346) highlights ozone concentrations continue to drop across the United States. Concurrent with these improvements has been the dramatic decrease in NO_X emissions from power plants while increasing production. These same trends have occurred in Texas, but to a more impressive degree. As fully documented by the TCEQ in its August 17, 2018, submittal of the Texas Transport SIP Revision, NO_X emissions and ozone formation trends clearly demonstrate that emissions from power plants have dropped significantly with no indication that the trend will reverse. Specifically, overall anthropogenic ozone precursor emissions in Texas have declined substantially (over 35 percent).

Commenter (0346) continues, these NO_X emissions reduction trends are the result of proactive joint initiatives by Texas power plant operators and the TCEQ and the over-arching state regulatory framework, including 30 Texas Administrative Code (TAC) Chapter 117 (Control of Air Pollution from Nitrogen Compounds and the Emissions Banking and Trading of Allowances program has implemented annual NO_X emissions caps for grandfathered and electing electric generating facilities). Despite these significant reductions, this rule imposes significant additional controls on Texas power plants. A good example of how disparately Texas is treated is the relative treatment of Wisconsin and Texas. According to the EPA’s analysis in their Technical Support Documents, a major driver for including Texas in the Group 3 Ozone Season NO_X Program was three monitors in Wisconsin (only one of which is predicted to average a NAAQS exceedance in 2026) to which the entire state of Texas allegedly contributes a total of 1.25-1.71 percent of the overall ozone formation. In exchange for that extremely small contribution, Texas power plants (which constitute a small portion of total Texas emissions) are required to drastically reduce NO_X emissions by 2026 by 17,240 tons. Contrast Wisconsin, which has a power plant fleet NO_X emissions rate higher than Texas (0.8 lbs/MWhr versus 0.7) according to EIA data, and only has to reduce NO_X by 155 tons by 2026 (a mere 4 percent cut).

Response:

Each upwind state covered in this action is treated the same way under the 4-step framework applied in this rule and no state is singled out unfairly. Where states have a larger amount of emissions reduction required, this is simply a function of the number of sources in that state and/or the absence of emissions controls at those sources that other states may have already required. This is a reasonable and entirely expected result of the EPA’s judicially upheld approach at Step 3 of applying a uniform control stringency across linked upwind states to eliminate significant contribution. Section V.D describes the EPA’s approach at Step 3 to addressing each state's "fair share," with the EPA's Step 3 analysis including an equally stringent reduction from the downwind state (*e.g.*, Wisconsin EGU reductions and corresponding impact on the State's receptors are included in 2026). In other words, the EPA is treating Texas and Wisconsin equally in its analysis. In response to commenter 0346, the EPA's assessment of TCEQ's modeling accompanying Texas's good neighbor SIP submission for the 2015 ozone NAAQS is provided in the separate rulemaking disapproving that submission. 88 FR 9336 (February 13, 2023).

4.6 Consideration of Volatile Organic Compound (VOC) Emissions or Other Pollutants

4.6.1 Consideration of VOC Reductions

Comment:

Commenter (0436) UDAQ was asked to contribute inventory inputs for the 2016v2 modeling effort without a clear acknowledgement from EPA as to what the inputs would be used for. As a result of this lack of transparency from EPA, the commenter believes that less than optimal inventory inputs and assumptions were included in the development of the 2016v2 platform including the potential underestimation of VOC emissions from relevant sectors. It is especially important that the inputs used when modeling ozone accurately represent both oxides of nitrogen (NO_X) and VOC emissions as variability in the atmospheric chemical regime will directly inform and impact the efficacy of any identified controls. Thus, an underestimation in VOC emissions may result in significant uncertainties around the amount of emissions reductions required to attain a standard as well as the best control strategy to implement. Additionally, it is well known that estimating biogenic emissions is a significant challenge, with current products generally underestimating peak concentrations of key biogenic VOC species, and it does not appear that the EPA made any substantive improvements to address these underestimations. Commenter (0436) requests that the EPA provide further justification for not including emissions reductions strategies for VOCs, especially in light of the fact that the EPA's own modeling indicates that the proposed reductions fall well short of reducing upwind contributions below the 0.70 ppb threshold.

Response:

The EPA has addressed inventory comments on the 2016v2 emissions in developing the 2016v3 emissions platform that was used for this final rule. As part of these updates, the EPA is using the most recent version of the Biogenic Emissions Inventory System (BEIS4) along with the most recent Biogenic Emissions Landuse Database (BELD6) to calculate biogenic emissions of VOC. These and other emissions platform updates are described in the 2016v3 Emissions Modeling TSD.

The commenter requests that the EPA provide a justification for not reducing VOC emissions to lower upwind state contributions to below the 0.70 ppb screening threshold used by the EPA in Step 2 of the 4-step interstate transport framework. As described in the preamble Sections III.B, V, and VI.B,the purpose of the GNP is to eliminate significant contribution and not to reduce the contribution from individual upwind states to below the 0.70 screening threshold.

Comment:

Commenter (0539) notes as with NO_X, utilities are an extremely negligible source of VOCs—about 0.14 percent in the state of Minnesota in 2021 compared to the top emitters of 28 percent from prescribed fires and 22 percent from solvent utilization. Here, too, highway and mobile sources are a significant contributor of VOC emissions, at about 22 percent. To 22 percent. To achieve its interstate transport obligations and objectives for attainment and maintenance of the 2015 ozone NAAQS, the EPA must focus its regulatory efforts beyond just stationary sources of NO_X.

Response:

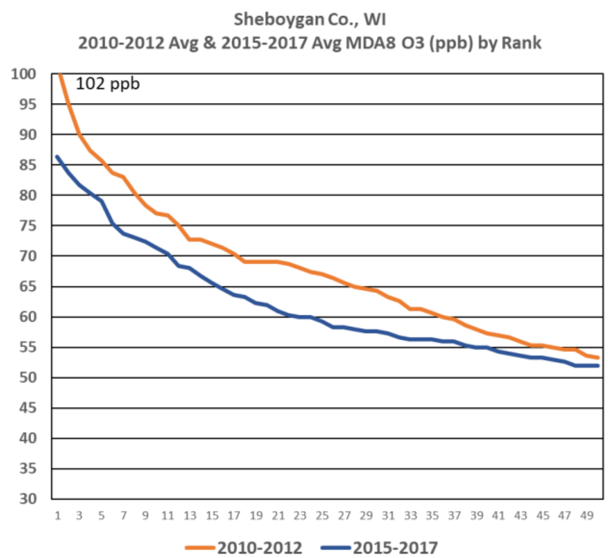
Comments on VOC emissions reductions are addressed elsewhere in this section. See also Section V.A of the preamble.

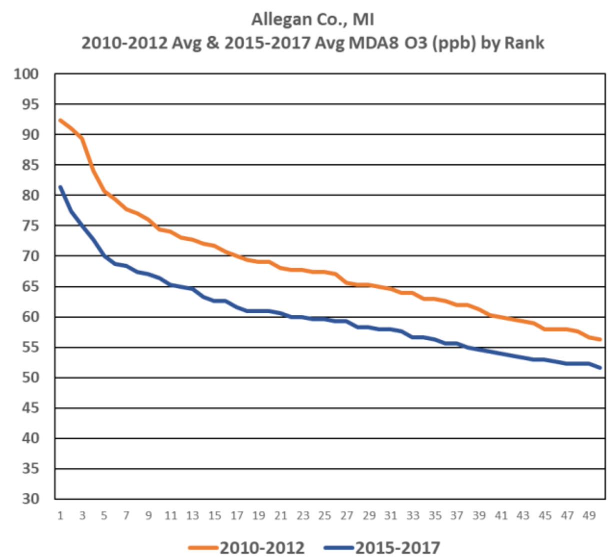
Comment:

Commenter (0531) adds presentations by the EPA representative Norm Possiel of the EPA's Office of Air Quality Planning and Standards, indicates that the EPA is well aware that reductions in transported NO_X over the last ten years have not reduced ozone formation in the NYMA and Chicago nonattainment areas. In his presentation "Analysis of Ozone Trends in the East in Relation to Interstate Transport," dated May 14, 2018, Mr. Possiel identified an analysis conducted by the EPA which refutes the basis for the EPA's proposed control strategy. This presentation indicates that the EPA believes the NYMA ozone nonattainment area, which includes the Connecticut monitors that the EPA identifies as nonattainment monitors in 2026 supporting the proposed rule, may be "oxidant limited", based on the EPA's air quality analyses. The EPA postulates that the NYMA is oxidant limited because, while the EPA's analyses shows that ozone and NO_X transported into the NYMA has been reduced by 5-10 ppb at rural New York monitors between the analytical years (2010-2017), there has been no similar reduction of ozone at the relevant Connecticut monitors. Commenter notes that the EPA did not respond to comments by Ameren and MOG regarding the EPA's analysis indicating that the control strategy in the Revised CSAPR Update would not result in reduction of ozone in the NYMA. Commenter believes that the EPA has an obligation to include in the docket all scientific reports and analyses both supportive and antithetical to their proposed control strategy. The EPA did not do that for the Revised CSAPR Update and should not ignore their obligation to discuss the science underlying the proposed FIP

Response:

The EPA disagrees with commenter's interpretation of the May 14, 2018, presentation. First, the presentation does not address or opine on ozone trends in the Chicago nonattainment area. Rather, as shown in figure below (slide 22 in the presentation) ozone concentrations at the traditionally high ozone sites downwind of the Chicago urban areas in Sheboygan, WI and Allegan, MI declined substantially between the period 2010-2012 to 2015-2017.





Regarding ozone trends at high ozone sites in Coastal Connecticut in the New York City nonattainment area, the EPA has updated the analysis from the May 2018 presentation to include more recent data based on measurements in 2019, 2021, and 2022.[74] The latter period reflects the impacts on ozone of more recent emissions reductions including, but not limited to, EGU NOx reductions resulting from implementation of the CSAPR Update. The figures below show 3-year average ranked MDA8 ozone concentrations for 2010-2012 and 2015-2017[75] that were described in the May 2018 presentation and the more recent 2019-2022 data for each of the four ozone receptors in Coastal Connecticut (*i.e*., Greenwich, Madison, Stratford, and Westport). The figures show that ozone concentrations across the distribution of values, including the top five ozone days, have notably declined when comparing the 2019-2022 data to the data from the two earlier time periods at each of these receptors. These results align with the findings by Koplitz, et. al, (2022)[76] that the New York City area is continuing to transition from a VOC-limited chemical regime to a more NOx-limited regime on high ozone days such that additional NOx reductions will further reduce ozone concentrations at these receptors.

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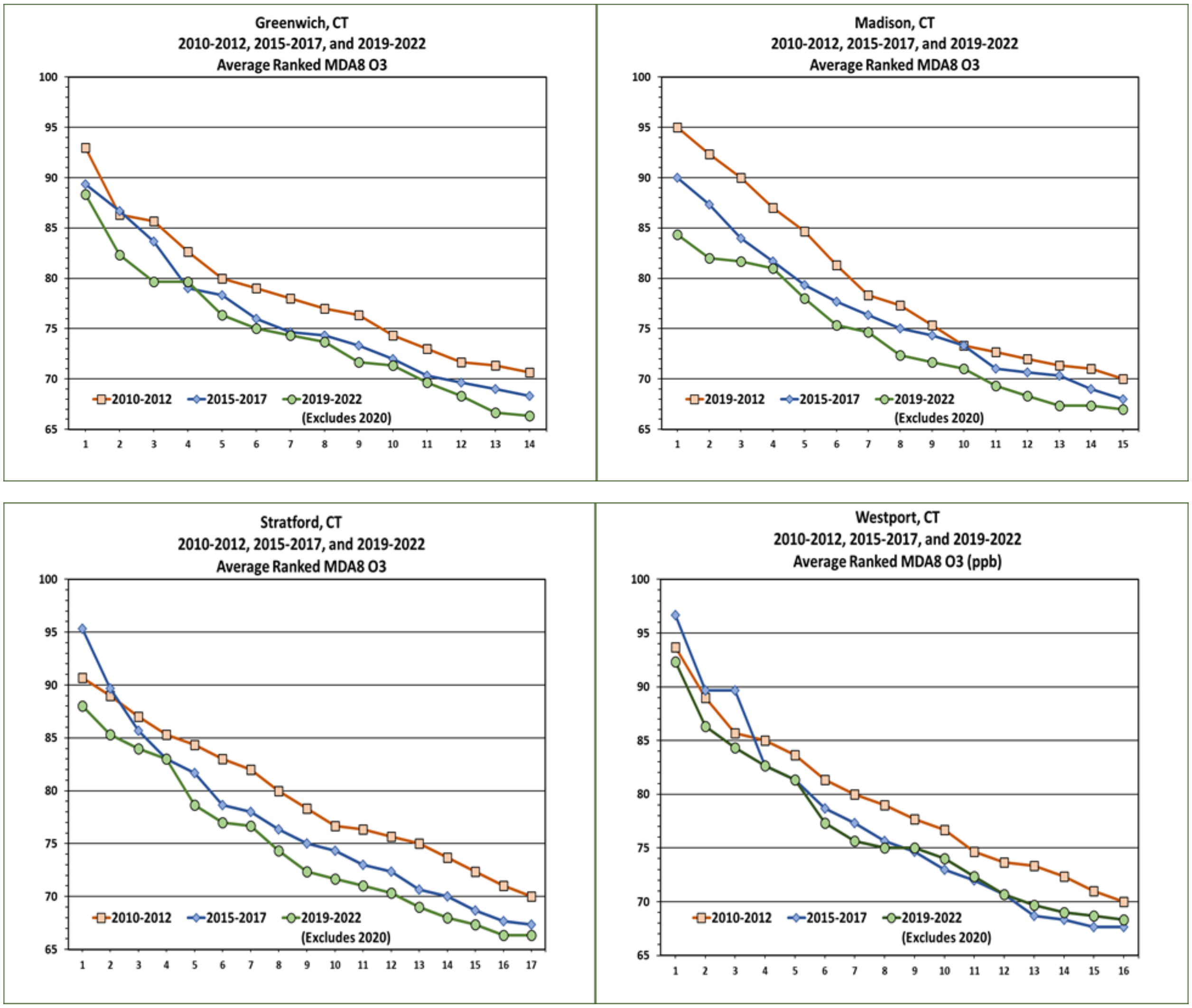
[74] Data for 2020 were excluded from this analysis to avoid any confounding effects on air quality of COVID-influenced transitory impacts on anthropogenic emissions during that year.

[75] Measured MDA8 ozone exceedances from May 25 through May 28, 2016, were excluded from this analysis to avoid any possible confounding effects of atypical influences on ozone concentrations from the Ft McMurray wildfires in Canada.

[76] Koplitz, S., H. Simon, B. Henderson, J. Liljegren, G. Tonneson, A. Whitehall, and B. Wells. Changes in Ozone Chemical Sensitivity in the United States from 2007 to 2016. *ACS Environmental Au* **2022** *2* (3), 206-222.DOI: 10.1021/acsenvironau.1c00029



Comment:

Commenter (0365) states a simple linear regression analysis of Louisiana NO_X emissions and Texas monitor values shows that statewide NO_X emissions are not statistically related to Texas monitor values, and in some cases the relationship is negative. The EPA has erroneously targeted Louisiana NO_X as a driver of Texas ozone. Reductions of NO_X in Louisiana do not show a related reduction in ozone at the identified Texas monitors. The EPA's proposal is limited only to NO_X emissions and fails to recognize that volatile organic compounds (VOCs) can be a matter of significant concern. The EPA has wrongly concluded that the actions required in Louisiana by this proposed FIP would result in any meaningful improvement in air quality. Louisiana recommends that the EPA perform source/sector tagging to determine which sources are actually contributing to the exceedances in Texas.

Response:

The EPA disagrees with the commenter that the EPA has erroneously linked emissions in Louisiana to receptors in Texas. The EPA also disagrees that reductions in VOC should be a significant concern for this rulemaking. The commenter provides no explanation for the figures in their comment document which the commenter claims show that NOx reductions in Louisiana will not reduce ozone at the Texas receptors. More importantly, the use of simple linear regression between emissions in Louisiana and ozone in Texas does not account for the meteorological conditions and nonlinear chemistry that result in transport from Louisiana to receptors in Texas. As indicated in the table below, the EPA's ozone contribution modeling indicates that ozone contributions from Louisiana at receptors in Texas are almost exclusively under NOx-limited chemical conditions such that reductions in NOx will lower Louisiana's contribution to these receptors. The table below provides the 2023 average and maximum design values, the contributions from Louisiana, and the portion of the contribution attributable to anthropogenic NOx emissions in Louisiana for each of the receptors to which Louisiana is linked based on the 2016v3 modeling. The data show that 95 percent or more of Louisiana's contribution is tied to anthropogenic NOx emissions in that state.

Table 4-1

Site ID	County	Receptor	2023 Avg DV	2023 Max DV	2023 Contributions from Louisiana (ppb)	Percent of Contribution from NOx Emissions
480391004	Brazoria	Manvel Croix Park	70.4	72.5	5.21	95%
481210034	Denton	Denton Airport South	69.8	71.6	2.87	98%
481671034	Galveston	Galveston	71.5	72.8	9.51	97%
482010024	Harris	Houston Aldine	75.1	76.7	4.75	96%
482010055	Harris	Houston Bayland Park	70.9	71.9	5.49	96%
482011034	Harris	Houston East	70.1	71.3	5.62	95%
482011035	Harris	Houston Clinton	67.8	71.3	5.44	95%

Regarding commenter's request to the EPA to perform source/sector tagging, for the proposed rule the EPA performed source apportionment modeling to quantify the contributions, by state from EGU and, separately, from non-EGU emissions in 2026. The contribution data from this modeling can be found in the file "2026_EGU_nonEGU_contributions.xls" which is in the docket for this rule.

Comments:

Commenters (0315, 0316, 0323, 0331, 0351, 0365, 0372, 0394, 0395, 0411, 0436, 0528, 0531, 0539, 0547) believe the proposed action focuses on NO_X emissions reductions. The EPA should consider proposing VOCs emissions reductions in upwind states that pollute areas more heavily impacted by VOCs. Much of this VOC pollution comes from industrial sources, as well as from mobile vehicles. Reducing emissions of volatile organic compounds, which include carcinogens like ethylene oxide, as well as other hazardous air pollutants, will have additional benefits for environmental justice communities.

Commenter (0547) argues the EPA should conduct additional, regional-specific analyses in support of its conclusion that the ozone is not VOC- limited—especially given the EPA's previous conclusions that "[i]n urban areas with a high population concentration, ozone is often

VOC-limited." Moreover, the EPA based its modeling on combined NO_X and VOC emissions. See Air Quality Modeling Technical Support Document, at 20, 22.51. The EPA recognizes that VOCs play an important factor in ozone reduction, stating, "Reducing NO_X emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs." Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, at ES-14. The EPA should reconsider exclusion of regulation of VOCs.

Commenter (0315) references in a separate guidance document, the EPA states, "In urban areas with a high population concentration, ozone is often VOC-limited." This has been substantiated along the NFR, from Denver north to Fort Collins. A study by ENVIRON for the Denver Regional Air Quality Council states, "There is not yet enough information about the relationships between changes in weekend emissions and local photochemistry to draw definitive conclusions about the implications of this effect for NO_X or VOC limitation along the Front Range. What is clear, however, is that reductions in NO_X are more likely to have a disbenefit in central Denver and perhaps downtown Fort Collins, where NO_X titration plays a significant role in net ozone formation during the day." This suggests the possibility that reducing NO_X could actually increase ozone by disrupting a complex chemical equilibrium between NO_X, VOC, and ozone. Additionally, there are two receptors closer to Wyoming that are impacted equally by Wyoming contributions as stated in proposed rule. The two receptors are in attainment with the ozone standard. This would suggest the real source contributing to the nonattainment receptor is the front range urban sources.

Commenters (0531) cites a paper resulting from LISTOS, where the researchers found that "In the most populated regions of NYC, ozone was sensitive to anthropogenic VOCs (AVOCs), even in the presence of biogenic sources. Within this VOC-sensitive regime, AVOCs contributed upwards of ~20 ppb to maximum 8-h average ozone. VCPs accounted for more than 50 percent of this total AVOC contribution. Emissions from fragranced VCPs, including personal care and cleaning products, account for at least 50 percent of the ozone attributed to VCPs.

Commenter (0531) shows that model simulations of ozone depend foremost on the magnitude of volatile chemical product emissions and that the addition of oxygenated volatile chemical product chemistry impacts simulations of key atmospheric oxidation products." (from abstract) In summary, the abstract for this paper indicates the researchers found that the NYMA was VOC sensitive during the period studied. This would indicate that the EPA's analysis of their modeling where they determined most ozone was produced under NO_X limited conditions is not likely correct in the NYMA and NO_X reductions in not have a significant impact at the critical New York/Connecticut monitors used as a basis inclusion of several states in this proposed FIP.

Commenter (0531) continues, nowhere in the EPA's proposed FIP does the EPA analyze or even mention the LISTOS 2018 study, the resulting data or the peer reviewed science resulting from the study. The EPA ignores the wealth of information collected during the LISTOS 2018 study and the resulting peer reviewed research published as a result. Ameren was unable to identify a reference in the docket for the proposed FIP (Docket ID: EPA-HQ-OAR-2021-0668) where the EPA mentions LISTOS 2018 or its participation in this study. It is arbitrary and capricious for EPA to participate in such research studies designed to inform ozone control strategies and to ignore those contemporaneous studies when developing an ozone control strategy largely reliant on the NYMA nonattainment monitors studied during LISTOS 2018.

Commenters (0323, 0331) continue, the modeled VOC and NO_X emissions tracers in the EPA's APCA modeling can give a general indication of the VOC/NO_X sensitivity, but the EPA assigning definitive numerical values to that sensitivity provides inaccurate projections, especially using APCA that is known to have a bias toward attributing ozone to NO_X emitting anthropogenic sources under VOC sensitive conditions. As documented in the CAMx v 7.10 User's Guide, "when ozone formation is due to biogenic VOC and anthropogenic NO_X under VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NO_X present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NO_X sources and less ozone formation attributed to biogenic VOC sources." Here, it is believed that as applied in this case (with biogenic emissions as an uncontrollable source group), the EPA has overestimated the efficacy of NO_X controls on these receptors as modeled results have a bias toward attributing more ozone formed to NO_X emissions than VOC emissions.

Commenter (0531) continues, in a presentation by UMD researcher Dale Allen at a CMAS conference in November 2021, Mr. Allen reported on a modeling exercise of 2016 emissions and meteorology. The results of that modeling exercise indicates that significant VOC limited chemistry was modeled in both the NYMA and the Chicago NAAs. It is worth noting here that this modeled conditions before the NO_X reduction required in 2017 by the CSAPR Update rule. It is also worth noting that the source apportionment modeling was qualified by the following statement on Slide 3: "Caveat: While the SA_Use_APCA flag was set to .true. in the job script, the SA_Use_APCA_Ptoverride flag was not set and defaulted to .false. in these simulations. Preliminary analysis suggests that this oversight likely led to an underestimation of the contribution of anthropogenic sources to O_3, especially during periods of VOC-limited chemistry."

Commenter (0531) adds, the modeling performed by Allen uses the APCA CAMx source apportionment technique which states according the CAMx Users' Manual 7.10: "Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NO_X sources and less ozone formation attributed to biogenic VOC sources." This option tends to overestimate the percentage of NO_X limited conditions. So, while Allen indicates that the modeling shows significant VOC limited chemistry in the Chicago and NYMA NAAs, it likely underpredicted those conditions in modeling of conditions in 2016. Because 2016 pre-dates the last two rounds of required CSAPR NO_X Ozone Season Allowance budget reductions, the modeling can be presumed to under-predict the VOC limited conditions at present in these areas.

Commenters (0323, 0331) argue regions around Lake Michigan demonstrate a significantly higher percentage of ozone formed by VOC (blue in color) compared to NO_X than most of the eastern US. This observation is seen both on modeled days greater than 60 ppb and on the top ten days of the ozone season (days used in RRF and significant contribution calculations). It is also noted that these estimates are a very conservatively high estimate of NO_X limited conditions for these coastal areas. In addition to the previous comments highlighting that APCA is known to have a bias toward attributing ozone to NO_X emitting anthropogenic sources under VOC sensitive conditions, the UMD analysis suggests that model configuration led to an underestimation of the contribution of anthropogenic sources to ozone formation, especially during periods of VOC-limited chemistry.

Commenter (0528) argues the EPA's failure to address the VOC-limited chemistry of the Chicago area and, consequently, the imposition of reductions that may increase ozone at the Chicago-area monitors is arbitrary and capricious. The Chicago area is one of the few regions in the United States where ozone is still characterized by "VOC-limited" chemistry. In a NO_X -limited regime, ozone will decrease when NO_X emissions are reduced. In a VOC-limited regime, on the other hand, ozone may not change or may actually increase when NO_X emissions are reduced. In other words, the VOC-limited chemistry dampens the responsiveness of ozone to NO_X emissions controls.

Commenter (0528) continues, the EPA's sweeping conclusion that the "vast majority" of downwind air quality areas are NO_X -limited fails to recognize the unique chemistry of the Chicago-area monitors to which Texas is linked. As noted in the Sonoma Report, local NO_X controls were modeled to show an increase in ozone in the Chicago area by as much as 0.45 ppb. It is unreasonable and arbitrary for the EPA to require upwind NOx reductions in Texas without determining whether they would increase or decrease ozone at downwind monitors. Such a result is contrary to the purpose of the good neighbor provision and to the CAA more broadly.

Commenter (0528) clarifies, the concern is not that the EPA should have included VOC reductions in the proposed FIP. Rather, the EPA failed to evaluate the actual photochemistry in the sole area the Agency linked to Texas. As a result of the EPA's inadequate assessment and modeling, the Agency force-fit Texas into a one-size-fits-all shortcut that erroneously equates a given set of upwind NO_X reductions to a given increment of downwind ozone reductions.

Commenter (0324) states the EPA does not evaluate the impact of VOC emissions on transport despite evidence that some nonattainment and maintenance monitors are in VOC-limited areas. The EPA concludes that the "vast majority" of downwind state receptors in the areas addressed by this rule are "NO_X limited" (and therefore require only additional NO_X emissions reductions to improve air quality). This is insufficient reason for the EPA to avoid analyzing the impact of VOC emissions reductions, which can also benefit NO_X limited areas. A rule that seeks to benefit only the "vast majority" of such areas is, by definition, insufficient to address all the areas the rule must cover, as required by the CAA. There is compelling evidence that some of Wisconsin's 2015 ozone NAAQS nonattainment areas are either VOC limited or are "transitional areas," meaning that ozone levels would improve with additional reductions of both NO_X and VOCs. The Chicago and Milwaukee areas, in particular, are shown to be more VOC sensitive, and could be expected to benefit from additional VOC reductions. There is, therefore, a compelling scientific basis for the EPA to regulate VOC emissions from states upwind of Wisconsin. The commenter references WDNR study ("Observation-Based Analyses of the Sensitivity of Ozone Formation in the Lake Michigan Region to NO_X and VOC Emissions," reports completed by UW-Madison to support the narrative.

Commenters (0323, 0331, 0351, 0394, 0395, 0411, 0531) cite modeling performed by the EPA and the LMOS 2017 study both showing the models underpredicted ozone concentrations in the Lake Michigan region. LMOS 2017 study researchers have experimented with increasing anthropogenic VOC emissions and decreasing anthropogenic NO_X emissions. These emissions changes improved air quality model performance reducing the negative bias. VOC speciation and spatio-temporal release patterns should also be reviewed. This evaluation by the LMOS 2017 research scientists indicate there are significant errors in the quantity and speciation of the VOC/NO_X emissions used in the EPA's air quality modeling platform to characterize Step 1 nonattainment as well as state contribution to ozone in Step 2 of the EPA's analyses linking these states to critical nonattainment monitors.

Commenters (0323, 0331, 0531) continue, several downwind nonattainment monitors in urban areas around Lake Michigan have recently been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NO_X control and that high ozone days in the region were predominantly VOC-limited in nature. This was demonstrated in multiple ozone episodes extensively evaluated in the LMOS 2017 study where ozone precursor measurements indicated relative increases in VOC concentrations with increases in ozone and where biogenic VOC increases outpaced those of anthropogenic VOC. Commenter (0531) provides the example, the June 2, 2017, episode which produced the highest ozone concentrations at both Sheboygan and Zion, Wisconsin monitoring sites was predominately VOC-limited (Abdioskouei & et al, 2019). Biogenic VOC increases outpaced those of Anthropogenic VOC.

Commenter (0531) adds in a recent paper which has resulted from research conducted under the 2017 LMOS the authors discuss the chemistry that is occurring on a 10-hr trajectory from the northern Indiana and Chicago areas terminating at the Zion, Illinois super site monitor on June 2, 2017. For their analysis, the researchers used NEI 2014 emissions and modeled from hours 8-17 CST. The modeling indicated that during transit from northern Indiana and Chicago area that the ozone chemistry was highly VOC sensitive and formed ~53ppb ozone. However, measurements made at the Zion site based on the ratio of H_2O_2/HNO_3 the ozone chemistry appears to be NO_X-limited. According to their paper, "As illustrated in Figure 2, the sensitivity of O_3 production at the Zion site, as defined by the ensemble average in H_2O_2/HNO_3, appears to indicate NO_X sensitivity on average. In contrast, the 2 June O_3 exceedance event presented in Section 4.1 indicates that O_3 production in this airmass was largely VOC sensitive."

Commenters (0323, 0331) note in contrast to the peer reviewed research resulting from the 2017 LMOS data collection effort, the EPA recently documented its support for additional NO_X controls in stating that its "review of the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NO_X -limited, rather than VOC-limited." However, the current situation is that the modeling as conducted does not accurately characterize ozone levels on high ozone days, underpredicting by 10+ ppb, which is a huge error. Other studies indicate that, to better match actual conditions, the model needs less NO_X and higher windspeeds at lower levels.

Commenters (0323, 0331) state the review of the EPA's modeled NO_X and VOC contributions, by upwind state, focusing on the future year modeled days used in each receptor's Step 2 linkage calculation provides a different picture for monitors around Lake Michigan. Of the top future year modeled days impacting significant contribution calculations at the Chicago-Alsip monitor (170310001), half of the days are shown to have NO_X emissions contributions from upwind states below the 80 percent threshold noted by the EPA in determining NO_X -limited regions. This is an indicator that on those days, and from anthropogenic sources from those states, VOC controls may demonstrate meaningful impact on ozone concentration reductions at these receptors.

Commenters (0323, 0331) note researchers at the University of Maryland (UMD) have also found in a study of chemical transport model results that by 2023, model predictions of ozone formed under VOC-limited conditions are substantial near the Great Lakes. In a recent presentation, they document a source apportionment simulation, conducted with CAMx/APCA on future-year 2023 to determine the major contributing sources and states to air quality within nonattainment areas. Their findings indicate that ozone production under VOC-limited conditions is important at coastal locations near the Great Lakes.

Commenters (0323, 0331) go further, an independent review of the EPA's own NO_X and VOC contributions challenges the Agency's statement that "[o]ur analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NO_X -limited, rather than VOC-limited." This statement is based on all anthropogenic NO_X and VOC emissions from all upwind states and is defined as having NO_X emissions contribute to 80 percent or more of the ozone concentrations modeled at each receptor.

Response:

The EPA disagrees with commenters who claim that the EPA should consider VOC emissions reductions in addition to or instead of NOx reductions to address significant contribution from upwind states to nonattainment and/or maintenance problems in other downwind states. As an initial matter, commenters fail to recognize that the studies and analyses they cite regarding VOC-limited conditions, while relevant for the core portions of certain urban areas like New York City, Chicago, and Denver, are not indicative of the chemical regime associated with regional, interstate transport, which is NOx-limited. In this regard, the EPA believes that local VOC emissions reductions combined with NOx reductions would reduce ozone concentrations in the central parts of urban areas that are VOC-limited. However, the most recent scientific studies of measured and modeled data indicate that (1) the chemical regimes in the urban areas cited by commenters are transitioning from being mainly VOC-limited to NOx-limited, (2) that the traditional high ozone monitoring sites downwind of these urban areas are NOx-limited, and (3) outside of these areas, and perhaps Los Angeles, CA, the chemical regime in the remainder of the U.S. is predominately NOx-limited.

The EPA's focus on controlling NOx emissions to reduce regional transport is supported by a journal article by Roberts, et al., (2022) which provides the following summary of NOx-limited versus VOC-limited conditions in urban centers compared to downwind areas, based on published articles on this topic.

"To implement proper ozone control strategies, the regional sensitivity of ozone chemistry must be understood. NOx reductions will reduce ozone if the ozone chemistry in a given region is NOx-limited (Frost et al., 2006; Simon et al., 2015). If a city begins in the NOx-saturated regime, strategies focused only on reductions in the emission of NOx will initially lead to increases in ozone concentrations in the immediate urban area (Heuss et al., 2003; Murphy et al., 2007; Pusede et al., 2015; Simon et al., 2015; Nussbaumer and Cohen, 2020). In this case, VOC reductions would be the most useful strategy to immediately mitigate ozone pollution in the urban core. However, peak ozone production often occurs in NOx-limited regions downwind of major urban areas, so region-wide NOx reductions are always beneficial to reduce the population exposure to harmful concentrations of ozone (Sillman et al., 1990; Jin et al., 2020)."

Even from a local perspective, a comprehensive study of the chemical regimes in the Lake Michigan area based on ground level measurements, modeling, and satellite data indicates that while the urban portions of the Chicago area are still VOC-limited, "NOx emissions reductions in central Chicago will contribute to immediate reductions in ozone in outlying parts of the Chicago region, which have traditionally had the highest ozone concentrations in that area."[77]

A study by Koplitz et al., (2022) based on measured data and sensitivity modeling found that Chicago, New York City, and Denver are in transition from VOC-limited to NOx-limited chemical regimes. For these areas, the spatial extent of VOC-limited chemistry has contracted toward the urban core such that areas immediately downwind are becoming increasingly NOx-limited and regional areas further downwind remain NOx-limited. This finding is further supported by Jin et al., (2020).[78] A copy of these publications can be found in the docket of this final rule.

The commenter refers to the 2019 preliminary report on the Lake Michigan Ozone Study (LMOS) 2017 field campaign which was conducted "to address persistent violations of the ozone NAAQS in the coastal communities along the western shore of Lake Michigan" and claim that downwind nonattainment monitors in urban areas around Lake Michigan have recently been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NO_X control and that high ozone days in the region were predominantly VOC-limited in nature.

The EPA disagrees with this comment. First, the 2017 LMOS field study supporting the LMOS

[77] Dickens, A.F. Ozone Formation Sensitivity to NOx and VOC Emissions in the LADCO Region, Technical Report, September 9, 2022.

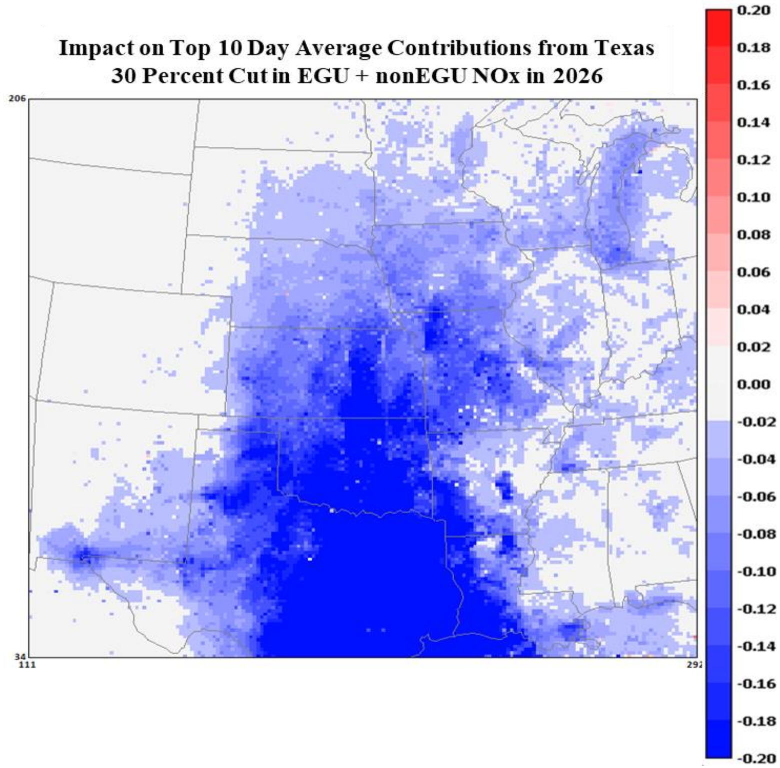
[78] Xiaomeng Jin, Arlene Fiore, K. Folkert Boersma, Isabelle De Smedt, and Lukas Valin. Inferring Changes in Summertime Surface Ozone–NO_x–VOC Chemistry over U.S. Urban Areas from Two Decades of Satellite and Ground-Based Observations, *Environmental Science & Technology* 2020 *54* (11), 6518-6529
DOI: 10.1021/acs.est.9b07785

2019 preliminary report focused on local ozone production and photochemical plume transport over the lake and along the shoreline, not the effects of regional transport. While the report concluded that local ozone production at the Zion measurement site near Chicago was VOC limited, ozone production at the downwind site in Sheboygan was NO_X-limited on half of the days with high ozone measurements. Second, the analysis in the report identified the presence of two different *local* photochemical regimens driving ozone production at the Sheboygan LMOS site which indicates the potential for different causes of high observed ozone. The LMOS 2019 preliminary report also states, "On high ozone days, the lowest lakeshore ozone concentrations are typically found in the areas with high emissions of nitrogen oxides (NOx), such as in central Chicago and northwestern Indiana. The highest [ozone] concentrations are found downwind of the high NOx sources in rural and suburban coastal areas." Third, the LMOS 2019 preliminary report notes that "regional background is characterized by elevated H_2O_2/HNO_3 ratios (used to infer NOx vs VOC-limited conditions), suggestive of NOx-limited ozone production." Thus, the results of the LMOS 2017 field study, as described in the report, actually *support* a conclusion that upwind regional NO_X reductions combined with local NO_X and VOC reductions would be an effective approach for reducing high ozone concentrations in the Chicago area. A copy of the 2019 Preliminary Lake Michigan Ozone study report can be found in the docket for this final rule.

The EPA recognizes that the commenter claims indicate that, to better match actual conditions (*i.e.*, improve model performance), the model needs less NO_X and higher windspeeds at lower levels. However, the commenter fails to identify these other studies. The commenter concludes from these other studies that "the model is therefore telling us that less NOx means more ozone. That also means that, proportionally, the attribution of ozone to out of state NOx predicts a higher impact than is actually occurring." LMOS preliminary report describes emissions perturbation air quality model runs which show improved model performance on the June 2, 2017, high ozone day at both the Zion field study site and a monitoring site in Chicago by reducing baseline NO_X emissions by 50 percent and increasing hydrocarbon (HC) emissions by a factor of 5. However, the applicability of these results is very limited and must be viewed with the understanding that the baseline emissions for the LMOS modeling were derived from emissions for 2011, not 2017 – which was when the field study was conducted. As described in the LMOS 2019 preliminary report, the 2011 NEI NO_X emissions were uniformly reduced by 28 percent in an attempt to account for changes in emissions between 2011 and 2017, while VOC emissions from 2011 were used without any adjustment. A comparison of 2011 vs 2017 NEI NO_X and VOC emissions for the three states within the field study modeling domain (*i.e.*, Illinois, Indiana, and Wisconsin) indicates that 2017 NO_X emissions were 38 percent lower, and VOC emissions were 18 percent lower in 2017 compared to 2011. In addition, the relative change in emissions between 2011 and 2017 varied by sector such that a uniform scaling factor applied to 2011 would not necessarily provide a representative estimate of the spatial distribution of emissions in 2017. Thus, the results of the LMOS emissions sensitivity runs are not immediately or inherently relevant to other air quality model applications, and these results, which are dependent on the emissions assumptions for the LMOS modeling and applicable to photochemistry within the local area, do not provide information to judge the attribution or impacts of upwind state NO_X emissions on ozone concentrations at receptors within the Lake Michigan area.

Commenters present tabular data showing the percent of daily ozone contributions attributed to NOx emissions versus VOC emissions at receptors in Kenosha, WI, Greenwich, CT, and Chicago/Alsip, IL on the top 10 concentrations days at each receptor. The commenter then refers to the EPA characterization of the relative contributions from VOC versus NOx emissions in the proposed rule to claim, incorrectly, that the EPA has adopted a threshold of 80 percent for determining whether a contribution is due to NOx versus VOC emissions. The commenter then applies an 80 percent threshold as criterion for assessing whether contributions on an individual day are due to NOx versus VOC emissions. Because there are days when the contributions from NOx emissions are less than 80 percent of the total contribution, the commenter claims that reductions of anthropogenic VOC emissions may generate meaningful ozone concentration reductions at these receptors. As expected, VOC emissions from those states that are immediately upwind wind of each receptor (i.e., Illinois for Kenosha and New Jersey and New York for Greenwich) made the greatest contribution to the total ozone contribution. In these cases where the contributions were from adjacent states, the contributions from NOx were still in the range of 60 to less than 80 percent on about half of the top 10 days at each receptor. In this regard, the EPA agrees that states in the Chicago and New York City nonattainment areas may want to consider both VOC and NOx emissions reductions as part of their local attainment planning. However, the data indicate that NOx emissions comprise the vast majority of the contribution from other more distant upwind states linked to these receptors.

One commenter presented a table showing the impacts on ozone contributions from Illinois that were predicted from a NOx sensitivity model run performed by the EPA for the proposed rule. In this contribution model run NOx emissions from EGUs and nonEGU in 2026 were cut by 30 percent in each state. The commenter notes that the contributions from Illinois to four receptors in Chicago (i.e., Alsip, South, Northbrook, and Evanston) as well as two receptors in Kenosha (i.e., Water Tower and Chiwaukee) and the receptor in Racine increased by amounts that range from 0.03 to 0.45 ppb. Based on the predicted increases in ozone resulting from decreases in NOx emissions, the commenter notes that ozone in the Chicago area is "exhibiting VOC-limited behavior." Using this information, the commenter then asserts that it would be unreasonable and arbitrary for EPA to require upwind NOx reductions in Texas without determining whether they would increase of decrease ozone at downwind monitors. The EPA disagrees with the comment that the EPA failed to evaluate the actual photochemistry in areas linked to Texas. The figure below shows the modeled reductions in contributions from Texas based on the same 30 percent EGU + nonEGU NOx cut sensitivity run cited by the commenter. The results clearly show that NOx emissions reductions in Texas will reduce ozone contributions from Texas in downwind areas including Chicago and at other receptors in the Lake Michigan area as well as at receptors to which Texas is linked in Las Cruces, Carlsbad, and Hobbs, New Mexico.



Regarding the commenter who claims that "the modeling" underpredicts ozone concentrations by 10+ ppb on high ozone days, it is not clear whether the commenter is referring to modeling performed as part of the LMOS 2017 field campaign or the EPA's 2016v1 or 2016v2 modeling. The EPA has made substantial updates to its 2016-based modeling platform in response to public comments. These updates have significantly improved model performance. The EPA's response to comments on the EPA's model performance can be found in Section 3.2.2.

The EPA's response to comments regarding the EPA's use of the Anthropogenic Precursor Culpability Assessment (APCA) tool to quantify contributions from emissions from NOx and VOC emissions to ozone concentrations can be found in section 3.5.1.

5 Implementation of Emissions Reductions

5.1 NO_X Reduction Implementation Schedule

5.1.1 Regulate the 2022 Ozone Season, Given Court Opinions

Comments:

Finalizing the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards as soon as possible, and in effect no later than the start of the 2022 ozone season to be as consistent as possible with the court's direction in Maryland v. EPA, 958 F.3d 1185 (D.C. Cir. 2020). The commenter also believes that this rule should also constitute a "full remedy" for upwind state transport obligations.

A phased approach to emissions control implementation to ensure at least a partial remedy is in place for the 2022 ozone season, should the EPA be unable to finalize a transport rule by the start of the 2022 ozone season. According to the commenter, this will ensure that downwind states will benefit from upwind state emissions reductions as soon as possible, especially since many states will need to meet 2015 ozone NAAQS moderate area attainment dates in 2023.

Commenters (0214, 0741, 0780) argue the EPA must also require that sources reduce emissions more quickly. The proposal gives sources far more time than necessary to start to run their existing pollution controls or install new ones. People and nature cannot wait any longer for the benefits of this cleanup. If polluting sources have existing controls, they should be required to run them by the start of the next ozone season: May 1, 2023. If polluting sources do not have existing controls, they should be required to install and optimally run them by May 1, 2024.

Commenter (0379) states the Agency fails to note that these proposed controls are already too late for several marginal nonattainment areas, which are among the 36 EPA-identified nonattainment and maintenance problem areas. These areas failed to attain the standard by the August 2021 deadline and the EPA just proposed reclassifying them to the Moderate nonattainment classification. The public health benefits of the 2015 ozone standard are yet to be realized in these areas.

Commenter (0758) states a health-protective approach is required by court decisions that direct states and the EPA to implement the good neighbor provision consistent with the statutory command that downwind areas attain and maintain the ozone standard by specified deadlines. These deadlines for attainment and maintenance of the standard are not only "central to the ... regulatory scheme," Sierra Club v. EPA, 294 F.3d 155, 161 (D.C. Cir. 2002) (quoting Union Elec. v. EPA, 427 U.S. 246, 258 (1978)), but constitute the very "heart" of the Act. Train v. NRDC, 421 U.S. 60, 66-67 (1975). As the D.C. Circuit has repeatedly held, "an implementation plan violates the good neighbor provision if it fails to 'eliminate upwind states' significant contributions to downwind pollution by the statutory deadline for downwind states to meet the NAAQS for ozone.'" Under these decisions, the EPA must implement a full remedy that eliminates significant contributions to downwind nonattainment and interference with downwind maintenance, including by regulating emissions from sources other than power plants, unless it is impossible to do so. Wisconsin v. EPA, 938 F.3d 303, 319 (D.C. Cir. 2019).

Under the Act and these precedents, the EPA is legally required to secure reductions in emissions of ozone precursors from upwind states in advance of the 2024 deadline for marginal nonattainment areas to attain and maintain the 2015 ozone standard (*i.e.*, in 2023). Id.; 42 U.S.C. § 7511(a)(1); 83 Fed. Reg. at 65,892 ("data from the calendar year prior to the attainment date . . . are the last data that can be used to demonstrate attainment with the [ozone standard] by the relevant attainment date."). And the EPA is legally required to secure any reductions that are impossible to achieve by 2023 as expeditiously as practicable thereafter, and not later than 2026. Commenters applaud the EPA's decision to heed the attainment deadlines in the design of the proposed rule. However, as explained below, the EPA can and must require additional achievable and cost-effective pollution reductions and implement them sooner than proposed.

Response:

See Section VI.A of the preamble for discussion of the EPA's determinations regarding timing.

5.1.2 Timeline for Installation of Controls Should be Less Stringent

Comments:

Commenters (0338, 0371, 0394, 0529, 0545) argue any approach in the final rule should allow more time for utilities to implement responsive and cost-effective measures. Commenters (0338, 0371) state that extension requests should be considered on a case-by-case basis, although at least one commenter (0371) recognizes that engine control products and or replacement engine technology are currently commercially available to modify reciprocating internal combustion engines not currently meeting proposed NO_X limits. Furthermore, commenters (0338, 0545) believes that the EPA should incorporate a provision in the rule allowing for additional time upon a showing of need.

Commenters (0338, 0371, 0510) state with reference to the time needed to install various controls, the proposed phased approach would provide flexibility to complete upgrades in alignment with existing maintenance and overhaul schedules removing any additional burden on the reciprocating engine operator and would also potentially yield emissions reductions faster and in an overall relatively seamless progression. Commenter (0510) continues, this includes control mandates for the 2023 ozone season, which affects New York's ability to meet its 2024 attainment deadline as a moderate nonattainment area, and additional control mandates for the 2024 and 2026 ozone seasons, which will impact the 2027 attainment deadline for serious nonattainment areas, if applicable. This represents a much more forward-thinking methodology than previous iterations of the NO_X trading program that included emissions reduction deadlines years beyond downwind states' attainment deadlines. The phased approach will ensure upwind states achieve emissions reductions on a comparable timeframe as the NYMA states, and that the latter are not bearing the full brunt of emissions reductions in their attempts to come into attainment of the 2015 ozone NAAQS.

Commenter (0362) argues until the rule is final and the scope of required emissions reductions and implementation timeframe are certain, it is unrealistic of the EPA to expect sources to redirect resources from competing priorities to conduct costly full-scale design and engineering of controls to accelerate compliance with this rule.

Commenter (0394) also believes that the EPA's assumptions regarding the timing for installation of state-of-the-art combustion controls and SCRs should be revised to reflect that retrofit of these technologies is not achievable until 2024 and 2027, respectively.

Commenter (0539) states the Integrated Resource Planning (IRP) process determines current and planned electrical generation resources for the next 15 years. Utilities propose for consideration the type, number, and size of resources to generate electricity, as well as the timing or sequence of deployment. Proposed plans are evaluated by the state/stakeholders, modified, and approved or disapproved. The process is extremely complex and detailed, requiring enormous amounts of time, staff, and technical expertise. Within these IRPs, utilities like Minnesota Power have approved plans that commit to planned retirement dates for units, and energy production levels that meet the needs of customers for a reliable power supply and transmission and distribution system. The proposed FIP could significantly disrupt the IRP planning process already in place in Minnesota and other states by impacting available energy to dispatch on a 7x24 basis through forced changes to ozone season emissions beginning as early as 2023, less than one year from the date of the submittal of these comments.

Commenter (0539) points out that utilities, such as themselves have approved plans (within the Integrated Resource Planning (IRPs) process) that commit to planned retirement dates for units, and energy production levels that meet the needs of customers for a reliable power supply and transmission and distribution system. The commenter asserts that the proposed FIP could significantly disrupt the IRP planning process already in place in Minnesota (and other states) by impacting available energy to dispatch on a 7x24 basis through forced changes to ozone season emissions beginning as early as 2023. The commenter specifies a typical IRP within Minnesota can take two to three years from the start of the development process to final Commission approval. Then an additional two to seven years might be needed to execute the approved plan, which often include modifications or new environmental controls to existing generation, bringing new generation online, implementing new demand response or energy efficiency programs, or upgrades to the transmission system. Utilities and state public utility commissions cannot continue to conduct the IRP planning process in the face of such regulatory uncertainty and potential upheaval to generation plans, particularly in abbreviated compliance timelines that affect the largest units, which provide baseload power capacity to the electric system. The proposed FIP timeline does not allow for the IRP planning process to function as needed to ensure a reliable system and reasonable cost for customers.

Commenter (0782) states the EPA mistakenly assumes that operators will be able to optimize existing SCRs within 2 months and suggests 18 months.

Response:

As explained in Section VI.A of the preamble, the EPA has made modifications to its proposed implementation schedule which accommodates some of the concerns and considerations expressed by commenters.

As noted by commenter, the EPA's final rule assumed combustion controls for EGUs will not be in place for the 2023 ozone season but will be for the 2024 ozone season emissions.

In regard to IRP disruption, the EPA notes that prior rules such as NO_X Budget program, CAIR, CSAPR, mercury and air toxics (MATS), and Revised CSAPR Update have seen mitigation strategies implemented on timeframes of three years or less and have not disrupted the IRP planning or cause reliability challenges as suggested by the commenter.

Comments:

Commenter (0323) states the EPA's selection of 2023 as the analytical year for its assessments of the state plans fails to align the obligation of upwind states with downwind states in as much as certain nonattainment areas have delayed implementation of nonattainment controls until 2025 and beyond. The commenter states the EPA's statutory duty is to synchronize the "good neighbor" provision of the CAA, section 110(a)(2)(D)(i), with nonattainment and maintenance requirements of CAA including section 172 such that compliance burdens are mutually and equitably aligned among upwind and downwind states. In the case of the proposed rule, however, the EPA has failed to address the timing of the implementation of upwind controls relative to downwind controls thereby causing unnecessary and excessive emissions controls to be required by the upwind sources. The EPA's failure to comply with the CAA obligations to align upwind and downwind control obligations is compounded by the fact that the EPA delayed disapproving upwind state good neighbor plans far beyond the two years specified in the CAA for such action. The proposed disapprovals and FIP presume the significant contribution should be calculated without consideration of the downwind state delay in implementing emissions reductions and the effect on ozone concentrations, thus shifting a burden of otherwise unnecessary additional controls to the upwind states. The CAA, however, directs synchronization/alignment of upwind and downwind emissions reduction requirements. Synchronization as applied means if a downwind state delays action, then the upwind state would accordingly take good neighbor action on a schedule that mirrors the downwind implementation strategy. To accomplish this emissions control program any other way means that either the upwind or downwind state could be obligated to implement emissions control far beyond what they otherwise might have to implement as part of a synchronized/aligned program.

Commenters (0416, 0528), in general, claim that the EPA's transport rule has no consideration for implementation of nonattainment controls by downwind states - effectively shifting the burden of additional controls to the upwind states. The EPA has a duty to delay the upwind compliance date to align with the downwind state compliance deadlines. Both plans must be aligned with the same timeframes to avoid an inappropriate shifting of the compliance burden from one group of states to another.

Response:

This comment is responded to in Section IV.A of the preamble and in Sections 1 and 3.1 of the RTC.

5.1.3 Compliance Flexibility

Comments:

Commenter (0338) argues the EPA should extend the compliance date to the 2028 ozone season, given the amount time and effort that will be needed to implement controls. Commenter (0545) similarly states if Wisconsin remains in the FIP, the EPA should delay implementation of the rule until 2028. The commenter notes that per conversations with impacted members, proposing an effective date of 2026 will result in an insufficient amount of time given to manufacturers to comply with this rule.

Commenter (0362) states if the EPA moves forward and finalizes a rule, the EPA should establish the compliance date as May 1st of the year following three years from promulgation of a final rule. Said another way, if the EPA promulgates a final rule in April 2023, then compliance with the rule should be required on May 1, 2027. Such a schedule provides the opportunity for compliance with the final rule (*i.e.*, slightly longer than three years) that the EPA anticipated in its narrative at 87 Fed. Reg. 20,101.

Commenter (0507) suggests that a path for replacement of affected non-EGU units should extend the compliance deadline for at least an additional five-seven years, to 2031-2033. Under the proposed rule, as currently written, the commenter anticipates that over 100 of its units will be impacted across 16 compressor stations; implying that compliance (by 2026) would be difficult to accomplished. Commenter also mentions that the path to replacement is often more complex, with longer equipment lead times, significant outage planning, additional regulatory approvals (and potential attendant litigation) and other timelines not within an operator's control. The commenter believes that a case-by-case replacement alternative should allow sufficient flexibility to accommodate these challenges.

Response:

See Section VI.A of the preamble for response to these comments.

5.1.4 Insufficient Timeline

5.1.4.1 Project Evaluation, Development, Execution, and Commissioning Phases

Comments:

Commenters (0301, 0323, 0372) generally believe that the 36-month schedule (or installation by 2026) is an unworkable and inappropriate timeframe to accommodate scheduling, installation, and commencement of operation of over 100 EGU SNCRs and SCRs to comply with this program. The EPA assumes adequate supplies of both off-the-shelf hardware (such as steel, piping, nozzles, pumps, and related equipment) and the catalyst used in the SCR process when making the 36-month determination. Affected parties that must make this happen will undoubtedly struggle to achieve this and will certainly incur high costs to meet this arbitrary deadline.

Commenters (0338, 0360, 0362, 0545) state a project to evaluate, select, procure, design, obtain any necessary regulatory approvals for, install, and commission monitoring equipment such as CEMS would be necessary to most instances to begin adequate characterization of emissions for control technology selection and feasibility analyses. Most technologies, as not yet proven, would require tabletop feasibility analyses, regulatory approvals, pilot / bench sale testing, evaluation, selection, and design. If determined to be feasible, as a complex project typical "phase gates" would need to be completed in accordance with most organization's capital project management programs and corporate funding approval requirements. This would include but not limited to, following technology selection:

- Technical Specification / Scope of Work Development
- Bidding / Procurement Process
- Award of Original Equipment Manufacturer Contract
- Basic Engineering Completion
- Permitting
- Detail Design
- Construction / Installation / Automation Integration
- Training, Start Up & Commissioning
- Performance Validation

Commenter (0372) argues that state budget assumptions for future years (2026 and beyond) are unworkable, because state budgets reduce ozone season allocations based on emissions rates for combustion modifications for coal-fired units – rates that are unattainable by any type of boiler combusting bituminous coal by a large margin.

Response:

See Section V.B and VI.A of the preamble for response to comments on the amount of time provided for SCR retrofits on EGUs.

Regarding installation of CEMs, we note that for non-EGUs, CEMs is generally not being required, with the exception of certain non-EGU boilers. However, many of these units already have CEMs installed. Commenters have not established that, for the limited number of units that would be required to install CEMs, it is impossible to install and bring them into operation in the timeframes provided by the final rule. See Section VI.C.5 of the preamble ("compliance assurance requirements") and Section 6.a of the Final Non-EGU Sectors TSD.

5.1.4.2 Failure to Consider Industry Specific-Controls and Planning

Comments:

Commenters (0294, 0416) state installation of all required control equipment by the 2026 ozone season is impractical if all identified iron and steel emissions units remain regulated under the rule, and the rule needs to provide for compliance extensions consistent with other regulations. Commenter (0416) goes further stating a Work Plan to identify an installation schedule is unnecessary due to the likely need to submit air permit applications (which is impractical within 180 days).

Commenter (0294) states electric arc furnaces are designed to run continuously. The furnace is lined with refractory brick and, once in operation, the refractory needs to remain hot. Once the furnace cools, the refractory could be damaged, and the furnace needs to be rebuilt before it can be placed back in operation. This operational life cycle is not unique to electric arc furnaces but is typical for other industrial furnaces that utilize refractory brick.

Commenter (0294) continues, in the normal course of operations, the furnace and the refractory can operate for approximately 15 years until worn refractory needs to be replaced. Typically, when a furnace is shut down to accomplish a relining of the refractory and refurbishment of the furnace, the shutdown lasts approximately 90 days. If a furnace is forced to shut down ahead of schedule, before the refractory has reached the end of its useful life, the furnace will still have to be relined before it can be restarted.

Commenter (0294) argues this proposed rule presents a significant concern, because the installation of control technology to reduce NO_X emissions will require any affected furnace to be shut down toto install the controls. The rule does not provide a sufficient time frame for installation of controls that would avoid an otherwise unnecessary shutdown and rebuild of the furnace. This proposed rule should provide sufficient flexibility to allow any installation of controls necessary to meet NO_X limits to occur at the next cold shutdown of an affected emissions unit, without accelerating the shutdown or requiring the remaining useful life of an affected unit to be lost.

Response:

See Section V.B and VI.A of the preamble.

Comment:

Commenter (0336) provides the listing of Virginia units that may be applicable to each proposed NOx limitation, which shows that a significant number of units and facilities in Virginia are likely to be subject to this rule that were not identified by the EPA. The commenter is concerned that with the increased number of units that may need some sort of controls under this rule, not all units may not be able to install control by 2026. The commenter adds that competition for vendors may be an issue as well as the need for state minor NSR permits, PSD permits, or permit exemption determinations. The commenter states that the EPA should consider the time needed for permitting paperwork necessary for the installation of controls, which are time- and resource-intensive endeavors. According to the commenter, depending on what decisions are made regarding the inclusion of the final FIP's requirements into the Virginia SIP, state operating permits may be the mechanism for source-specific requirements that will be included in Virginia's SIP, and the Department of Environmental Quality's (DEQ's) air permitting sections have few additional resources to devote to this new work. The commenter asserts that priority for permitting resources at DEQ must be given to new construction, which could further delay any necessary paperwork needed for the application of these controls and, if necessary, the adoption of the requirements into Virginia's SIP. The commenter adds that any future modeling analysis should include emissions estimates from these units listed in the attachment provided by the commenter as well as an assessment as to whether Virginia's contributions to downwind monitors may be over-controlled if all applicable units were to be included.

Response:

For non-EGU emissions units, the EPA asked a contractor to prepare an assessment of control installation timing for non-EGUs. The results of the assessment helped inform some changes in the final rule associated with the timing for installing non-EGU controls. See Sections VI.A and VI.C of the preamble.

5.1.5 Years 2023–2025

Comments:

Commenter (0266) states the EPA is proposing to reduce Ohio's NO_X budget by approximately 15 percent between 2022 and 2023. This is a significant drop in allocations. The commenter states the EPA may be overestimating the ability for Ohio sources to achieve further optimization of controls, especially considering the delicate balance required while maintaining compliance with the EPA's mercury emissions rules. Considering that we are in the second half of 2022, the commenter considers this accelerated schedule unachievable.

Response:

The EPA notes that the Ohio state emissions budget for the final rule does not reflect a 15 percent drop from 2022 levels. Rather, the final rule 2023 state emissions budget for Ohio is nearly equal to the 2022 state emissions consistent with the notion that Ohio's 2022 Revised CSAPR Update obligations are premised on the same technologies as Ohio's Good Neighbor Plan 2023 state emissions budget. See 2022 Unit and State-level Ozone Season Data File in the Docket for this rulemaking.

Comments:

Commenters (0300, 0353, 0355, 0550, 0411) state the EPA's compliance deadline for widespread installation of similar types of control devices across similar types of facilities is too short. Additional consideration should be given to the lead time necessary for design, equipment delivery, and site-specific fabrication for retrofits, especially during this time of unprecedented shortages of goods (*i.e.*, equipment) and services (*i.e.*, design and installation professionals). The additional planning necessary to accommodate plant shutdowns for installation of controls should also be considered.

Commenter (0322) states the compliance deadlines established by the EPA in the proposed rule do not allow sufficient time for electric generating units (EGUs) to replace lost capacity with lower-emitting sources by 2026. The commenter also states the deadlines for non-EGU controls should be extended. The unique supply of materials, transportation limitations, and workers during these times of geopolitical disruption triggered by the Russian invasion of Ukraine and ongoing COVID-19 pandemic-driven disruption raises significant concern about meeting deadlines. Reference to historical three-year installation timeframe by the EPA is not reasonably projected whether related to EGUs or non-EGUs emissions controls installation. The three-year default may prove to be unachievable, which the EPA concedes with its request for comments about the merit of allowing extensions of the proposed compliance dates. Commenter (0367) states the marginal area attainment deadline for the 2015 ozone NAAQS passed in 2021, with several states unable to reach attainment, and the moderate area deadline is swiftly approaching in 2024. Because attainment is based on the three preceding years' ozone levels, by the time the Proposal takes effect, two of these three years (2021 and 2022) will have already passed. The Proposal makes important reductions in upwind ozone pollution, but the EPA must further strengthen its requirements to eliminate upwind states' significant contribution altogether. If the EPA cannot eliminate significant contribution by the 2024 deadline, and downwind nonattainment persists beyond that, as projected, the EPA should not wait until the next attainment deadline in 2027 to provide a full remedy, but instead should implement measures, including those described below, to eliminate significant contribution as expeditiously as practicable. Furthermore, the commenter states if power plant controls are not available by 2023, then they should be required as soon as possible thereafter: the earliest possible of 2024, 2025, or 2026. Even if controls are potentially unavailable fleetwide for the beginning of the 2023 ozone season, if they are likely to be available sometime during the season, the EPA should still set emissions budgets for the year based on the time when they can be installed. Even if not all power plants can install SCR before 2026, as the EPA determined, that does not mean that none can. The EPA thus should consider phased emissions reductions as SCR installations become available.

Commenter (0324) states that to be consistent with the court decision in Wisconsin v. EPA, 938 F.3d 303 (D.C. Cir. 2019), the EPA needs to resolve upwind state transport obligations by the next applicable attainment date – which, for these areas, will be following the 2023 ozone season. Rather than fully resolving all upwind state contributions by 2023, the EPA's proposed rule will result in very few emissions reductions and only minor improvements in air quality in 2023, with slightly larger improvements in 2026.

Commenters (0352, 0503) support an accelerated finalization of this rulemaking. Commenter (0352) points out that although the rulemaking was not designed to consider upwind pollution reduction, it will aid the District of Columbia in attaining NAAQS ozone level compliance, as the rulemaking is expected to result in reductions in emissions from Maryland, New Jersey, New York, Pennsylvania, Virginia, and West Virginia – all of which contribute to DC's poor air quality.

Commenters (0329, 0411) states that a final rule in December 2022 is not sufficient time to plan, permit, and install SCRs at this many units, even with a planned in-service date of the 2026 ozone season. The commenter evaluated its ability to permit the installation of an SCR and believe it could not do so within the timeframe. The commenter also states that current supply chain issues will further complicate the installation timeline.

Response:

The EPA's timing determinations for this rule and response to these comments is in Section VI.A of the preamble.

Comments:

Commenters (0352, 0503) support an accelerated finalization of this rulemaking. Commenter (0352) points out that although the rulemaking was not designed to consider upwind pollution reduction, it will aid the District of Columbia in attaining NAAQS ozone level compliance, as the rulemaking is expected to result in reductions in emissions from Maryland, New Jersey, New York, Pennsylvania, Virginia, and West Virginia – all of which contribute to DC's poor air quality. Commenters (0329, 0411) states that a final rule in December 2022 is not sufficient time to plan, permit, and install SCRs at this many units, even with a planned in-service date of the 2026 ozone season. The commenter evaluated its ability to permit the installation of an SCR and believe it could not do so within the timeframe. The commenter also states that current supply chain issues will further complicate the installation timeline.

Commenters (0300, 0353, 0355, 0550, 0411) state the EPA's compliance deadline for widespread installation of similar types of control devices across similar types of facilities is too short. Additional consideration should be given to the lead time necessary for design, equipment delivery, and site-specific fabrication for retrofits, especially during this time of unprecedented shortages of goods (*i.e.*, equipment) and services (*i.e.*, design and installation professionals). The additional planning necessary to accommodate plant shutdowns for installation of controls should also be considered.

Commenter (0322) states the compliance deadlines established by the EPA in the proposed rule do not allow sufficient time for electric generating units (EGUs) to replace lost capacity with lower-emitting sources by 2026. The commenter also states the deadlines for non-EGU controls should be extended. The unique supply of materials, transportation limitations, and workers during these times of geopolitical disruption triggered by the Russian invasion of Ukraine and ongoing COVID-19 pandemic-driven disruption raises significant concern about meeting deadlines. Reference to historical three-year installation timeframe by the EPA is not reasonably projected whether related to EGUs or non-EGUs emissions controls installation. The three-year default may prove to be unachievable, which the EPA concedes with its request for comments about the merit of allowing extensions of the proposed compliance dates. Commenter (0367) states the marginal area attainment deadline for the 2015 ozone NAAQS passed in 2021, with several states unable to reach attainment, and the moderate area deadline is swiftly approaching in 2024. Because attainment is based on the three preceding years' ozone levels, by the time the Proposal takes effect, two of these three years (2021 and 2022) will have already passed. The Proposal makes important reductions in upwind ozone pollution, but the EPA must further strengthen its requirements to eliminate upwind states' significant contribution altogether. If the EPA cannot eliminate significant contribution by the 2024 deadline, and downwind nonattainment persists beyond that, as projected, the EPA should not wait until the next attainment deadline in 2027 to provide a full remedy, but instead should implement measures, including those described below, to eliminate significant contribution as expeditiously as practicable. Furthermore, the commenter states if power plant controls are not available by 2023, then they should be required as soon as possible thereafter: the earliest possible of 2024, 2025, or 2026. Even if controls are potentially unavailable fleetwide for the beginning of the 2023 ozone season, if they are likely to be available sometime during the season, the EPA should still set emissions budgets for the year based on the time when they can be installed. Even if not all power plants can install SCR before 2026, as the EPA determined, that does not mean that none can. The EPA thus should consider phased emissions reductions as SCR installations become available.

Response:

See preamble Section V.B and VI.A, along with the EGU NO_X Mitigation Strategies Final Rule TSD for response and information on control timing. The EPA further notes here that all of the EPA's optimization and combustion control assumptions for EGUs have been successfully implemented on similar timelines in the CSAPR Update and Revised CSAPR Update. Similarly, EGUs have installed SCRs on even shorter timeframes than that proposed by the EPA. The EPA proposal already allowed for additional time to accommodate the regionwide nature of the emissions budgets, and that timeframe for SCR retrofits is extended in this final rule to 36-48 months.

Comments:

Commenter (0380) states the proposed rule compliance timeframe is not consistent with the EPAs past decisions, and the market constraints that supported previous EPA decisions have not changed. 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. 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. The commenter also states 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). Finally, the commenter states 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. Commenter references a 2014 report cited by the EPA in the TSD and prepared for the INGAA Foundation, Inc, that contains, for example, a review of the various types and numbers of RICE inventoried, as support.

Commenter (0411) states the potential finalizing of the allowance budgets immediately before, or during, the 2023 Ozone Season is not feasible. The operational and fuel procurement planning for units is a coordinated effort that requires a lengthy period that is already underway for the 2023-2024 Planning Year. The ISO stem Operator ("MISO") 2023-2024 Planning Year begins June 1, 2023, and ends May 31, 2024. Unit planning is already occurring for May 2023 operation as well as for the 2023-2024 Planning Year. This necessary planning time was not considered in the EPA's implementation strategy.

Response:

The EPA addresses transitional aspects of the rule related to the 2023 ozone season, in Section VI.B.12 of the preamble. It further notes that the successful implementation of the Revised CSAPR Update starting during the 2021 ozone season illustrates the feasibility of this approach.

Comments:

Commenter (0422) also states it takes time to complete engineering, procure and receive necessary components, execute installation, and complete testing requirements, and three years are not enough. The large number of boilers (affected by the proposed rule) that would need additional controls would that in a normal market would cause high demand for boiler modification, construction, and installation services and likely lead to extended lead times for services – factors further complicated by the pandemic (*e.g.*, additional supply issues). The commenter suggests a minimum of five years for boilers that need modifications to comply with the proposed standard and a minimum of eight (8) years for boilers that would have to be completely replaced.

Commenter (0432, 0551, 0505) states feasibility studies, engineering design, permitting, equipment manufacture, installation, start-up and optimization, as well as current issues due to COVID-19 impacts and supply chain delays, may make this schedule difficult. Commenter (0505) mentions that in their state of Texas there are an estimated 132 sites with EGUs impacted by the proposed rule, of which approximately 55 percent do not currently have SCR/SNCR controls installed and would require retrofitting to comply. Commenter express concerns that the EPA fails to adequately consider the roadblocks and bottlenecks, or the retrofit difficulties within such a large-scale deployment, and that assumptions made about the feasibility are based on dated information (over 20-years-old) and an inadequate technical analysis. Commenter warns that if EGUs are not allowed sufficient time to add SCRs and are instead expected to retire, the loss of generation capacity would have a significant impact on electricity consumers in Texas.

Response:

The EPA addresses these comments on pollution control installation timing in preamble Section V.B, VI.A, and VI.B, and in the EGU NO_X Mitigation Strategies Final Rule TSD.

Comment:

Commenter (0503) states that if certain states in the rule's modeling, such as Maryland, do not attain the 2015 ozone standard by 2023, the rule should be adjusted to further reduce upwind state budgets to provide the necessary reductions in ozone concentration for the affected nonattainment areas. Specifically, the commenter requests that the EPA commit to reassess the FIP NO_X reductions, analytical tools, and methodologies, in the light of new monitoring information at the end of every ozone season to ensure that anticipated reductions were sufficient for all areas to meet the ozone standard by the applicable attainment date.

Response:

This final rule is intended to serve as a complete and durable remedy for the elimination of significant contribution from upwind states covered by the rule. There is no need evident to the Agency at this point in time to reevaluate the program through future rulemaking actions.

Comments:

Commenter (0510) recommends advancing emissions reductions through shorter-term SNCR installation. The commenter supports installing SNCR controls as soon as possible - as the EPA notes here, in time to reduce emissions in the 2024 or 2025 ozone season, depending on when the rule is finalized. Nonattainment areas have an obligation to attain the standards as expeditiously as practicable. The emissions reductions available through the installation of SNCR should be realized as soon as possible.

Response:

The EPA explains its implementation of SNCR-based reductions, specifically its coordination with all post-combustion control timing assumptions in Section V.B.1.d of the preamble.

Comments:

Commenter (0541) states that the EPA has no modeling indicating that Alabama is “linked” to any downwind nonattainment or maintenance receptor beyond 2023; therefore, the EPA cannot require any reductions from sources in Alabama beyond 2023. If EPA finalizes a FIP for Alabama, the state of Alabama’s budget should not change beyond 2023—the last year that the EPA’s modeling shows “linkages” to downwind states for Alabama.

Response:

The EPA notes that no additional stringency is applied to Alabama’s budget beyond 2023 in either the preset budgets or the dynamic budgets. Alabama’s preset, mass-based budget does *increase* slightly in 2024 relative to 2023 reflecting known, new units that are under construction. Similarly, the preset budget for Alabama adjusts downward slightly in 2027 reflecting scheduled retirements. In both cases, these do not reflect changes in stringency, but rather changes in the budget that preserve the level of stringency identified at Step 3 to eliminate significant contribution. The same holds true for any dynamic budgets that may produce state budgets that adjust relative to a prior year.

Comments:

Commenter (0547) objects to the 2025 initial start year, which is too early given the planned 2026 date for significant emissions reductions. The commenter notes the 2025 control year reflects the EPA’s drastic underestimation of the time to retrofit SCR onto existing units. The commenter also suggests the EPA should delay implementation of dynamic budgeting until after 2026 to give facilities the ability to properly plan and adjust to these significant changes.

Response:

Implementation of dynamic budgets begins in 2026 in this final rule, in conjunction with preset budgets, and full reliance on dynamic budgets does not begin until 2030. See Section VI.B of the preamble for further discussion.

Comments:

Commenter (0551) states CAA provisions with three-year deadlines have nothing to do with what is broadly achievable on a regional basis under a rule that will affect many units and multiple industries. The EPA's analysis likewise ignores other provisions of the CAA that allow provide longer deadlines, like the regional haze program's best available retrofit technology requirement, which provides sources with up to five years to comply, and the deadlines for attaining the NAAQS themselves, which can extend for multiple decades. The commenter also states the fact that the Agency has not been able to promulgate an interstate transport rule for the 2015 ozone NAAQS before now should not serve as a basis for penalizing states and companies that must now comply with interstate transport requirements. The commenter suggests the EPA permit case-by-case extensions of any final rule's EGU deadlines, like it proposes to do with non-EGUs.

Response:

See Sections IV.A and VI.A of the preamble for discussion of implementation timing in response to these comments. Unlike commenter's reference to the timeframes provided in the regional haze program of the Act (which relates to visibility improvement in national parks and wilderness areas), the provisions discussed in Section VI.A all directly relate to the good neighbor provision, the implementation of the ozone NAAQS, and/or timeframes provided by Congress regarding reductions in air pollution to protect public health.

Comments:

Commenter (0554) states the requirement to install LNB by 2023 is too tight. It is theoretically possible to install LNB within 10 months (meaning the process must begin immediately, before the proposed rule is finalized), this timeline presumes perfect execution of all required steps.

Response:

The reductions associated with combustion control upgrades for EGUs are not implemented until the 2024 state emissions budgets.

5.1.6 Years 2026 and Later

Comments:

Commenter (0235) states the effective date for the non-EGU control measures in the proposed FIP to be highly accelerated especially when compared to other EPA actions. For example, the recent EPA action regarding Heavy-Duty Diesel Equipment has a compliance implementation date of 2027.

Commenter (0257) agrees with need for maximum daily emissions rates for NO_X from large coal fired power plants. The commenter believes these should enter into force sooner than produced, in 2026, at the same time the emissions controls would be required for plants that now lack controls.

Response:

The EPA is retaining the daily backstop rates in this final rule, consistent with the comment. The dates at which these daily backstop rates take effect are discussed in preamble Section VI.B.

Comments:

Commenter (0266) states the EPA is proposing to set allocations at a level beginning in 2026 that would be achieved by retrofitting post-combustion controls for those that do not have advanced controls installed and this schedule is challenging.

Response:

Budgets, and corresponding allocations, reflect emissions reductions commensurate with SCR installation occuring over a 36-48 month time frame. This timing is discussed in preamble Section V.B and VI.A and in the EGU NO_X Mitigation Strategies Final Rule TSD.

Comments:

Commenter (0271) states the FIP would render moot the hundreds of millions of dollars our ratepayers have invested in enhanced NO_X controls, including enhanced combustion controls and Selective Non-Catalytic Reduction (SNCR) systems, and imposes a draconian edict that all plants install replacements to those systems – called Selective Catalytic Reduction (SCR) controls – in just three years from the start of the new program. It is simply not possible to accomplish the monumental task of universal SCR installation by 2026. Considering state and federal permitting requirements, as well as construction time and supply-chain issues, electric utilities will not have time or funds to install these expensive controls and, as you know as a grid operator, there will not be sufficient time to stage and stagger the planned outages necessary for such a massive construction project across the fleet. The commenter suggests the following:

1. Slow the process of this 'Good Neighbor' Plan to gain a true understanding of the impact on reliability and resilience of the electric grid.
2. Work with the North American Electric Reliability Corporation and RTOs to ensure the reliability and resilience of the electric grid is not compromised.
3. Return to the cooperative federalism approach enshrined in the CAA and withdraw the proposed Transport Rule FIP so the long-pending State Transport SIP Revisions can be meaningfully reviewed, and all issues resolved.

Response:

Budget changes for EGUs associated with SCR installation are phased in over a 36-48 month period in the final rule. Their timing concerns are addressed in the preamble, see Sections V.B and VI.A.

Comments:

Commenters (0284, 0320, 0437) state three years is not enough time to comply with proposed ozone season NO_X limits. First, commenter (0284) notes that retrofit projects are lengthy (*e.g.*, involve several steps including design, engineering, corporate financial approval, final design, permitting, procurement, construction, and start-up) and challenging. Second, lead times for critical parts are long–estimated to be 54 – 60 weeks. Commenter (0284) adds that a lead time of more than a year to receive necessary materials and parts would make it virtually impossible for a facility to comply. Third, fuel switching from coal to natural gas is complex. Fourth, air permit modification timelines may be long. Commenters (0284, 0320, 0437) mention that modifications to comply with the new proposed requirements could include various types of modifications – *e.g.*, fuel switching, combustion air system changes and add-on control device installation, which generally require a modification to a facility's air permit – a process that is not short, and in some states, limit when equipment can be purchased.

Response:

See preamble Section V.B and VI.B

Comments:

Commenters (0284, 0320, 0424, 0437, 0518, 0549) state the proposed rule's three-year installation deadline for non-EGUs does not account for timing to obtain necessary permits. Commenters describe, in general, how obtaining skilled labor and necessary components for such NO_X controls has become even more difficult during these times of geopolitical instability triggered by the Russian invasion of Ukraine, ongoing COVID-19 pandemic- driven disruption, and supply chain shortages, making compliance with a 3-year deadline more difficult. Commenters (0284, 0320) believe that the EPA should identify and rectify all areas of inefficiency, duplicity, and redundancy within its permitting and approval processes to give regulated entities certainty of outcome as well as timing of the approval of their applications. Commenters (0284, 0320, 0424, 0437, 0518, 0549) agree that the EPA should provide more time to meet the emissions limitations and associated compliance requirements, based on a demonstration of necessity.

Response:

See preamble Section V.B, VI.A, the EGU NO_X Mitigation Strategies Final Rule TSD, and Section 10 of this document for response to comment on labor and supply chain trends.

Comments:

Commenter (0295) states the timing of implementation is inconsistent. For example, the recent EPA action regarding Heavy-Duty Diesel Equipment has a compliance implementation date of 2027. If the intent is to have emissions reductions in place for Serious nonattainment areas in the 2027 O_3 season, why is this other regulation, which has the potential for much greater reductions over time, not also effective in 2027?

Response:

The basis for timeframes for rules promulgated under title II of the CAA are set out in those actions. This comment is beyond the scope of this action.

Comments:

Commenter (0321) states the facilities will need to be shut down and the rule should provide extensions of time beyond the 2026 ozone season (May 1, 2026) for the Glass and Glass Product Manufacturing Industry to meet the emissions limitations and other compliance requirements under the rule, upon a facility specific demonstration of necessity. In addition, the commenter states the EPA should not require compliance with the rules by a specific date that is divorced from the life cycle of any affected furnaces, since this would force affected glass melting furnaces to be replaced or upgraded before the end of their normal life expectancy. Commenter (0321) briefly describes the operational characteristics of flat glass furnaces, noting that they are design to run continuously (for up to 15 years), and once damaged must be rebuilt (at an est. cost of $50 million) before recommencing operations – an operational life cycle is not unique to glass furnaces and is typical for other industrial furnaces that utilize refractory brick.

Commenter (0330) states given the number of affected RICE across the 23-state region subject to the proposed FIP, the number of engineering and vendor/supplier resources may not be sufficient for the scoping, planning, construction, testing and commissioning within this limited timeframe. The EPA's proposal does not consider that a company that chooses to replace existing RICE units with new units must seek additional permitting approvals. This will require additional time for the overall process, especially if the project is located in vulnerable or other communities with environmental justice concerns. Commenter (0330) points out that of the to 50 of stationary, natural gas-fired, spark ignition RICE used by them in the intrastate transportation and delivery of natural gas, they anticipate needing to take additional actions (*e.g.*, installation of additional controls) for approximately 30 of the RICE to ensure compliance with the proposed emissions limits, resulting in possible grid reliability issues.

Commenter (0337) states compliance by the 2026 ozone season is not practical, and the rule should allow for extensions of compliance. The commenter anticipates a detailed step-by-step process (that requires, for example, tests and other research and development activities) to determine how it can comply with the proposed emissions limit, each step of which is going to be complex and time-consuming – *e.g.*, what is achievable for one furnace may not be achievable for another furnace.

Commenter (0760) claims that the EPA has erroneously concluded that LNB or (ULNB) systems can be designed, financed, and installed on existing units by the start of the 2026 ozone season. According to the commenter, a facility with multiple units would be required to shut down sequentially, and realistically, no more than two units could be retrofit in time for the 2026 ozone season. The commenter notes that there are several facilities with more than one unit slated for controls under the proposed FIP. The commenter also suggests that with the requirement for hundreds of units across the country needing to retrofit within a short period of time, there could be a shortage of LNB/ULNB and associated equipment. The commenter recommends that the EPA review the actual availability of such equipment before imposing any final FIP requirements.

Response:

See Preamble Section V.B and VI.A for response to these comments.

Comments:

Commenter (0329) states that in Minnesota, even if utilities could install equipment by 2026 (unlikely), they would only be able to use the equipment for 4-14 years given enforceable shutdown dates. The commenter also states Minnesota coal EGUs are unlikely to install new control equipment given the short payback period before retirement dates. That means they will need to operate coal units less than planned in the later years of the plan (2026-2032). Minnesota believes this is likely to push electricity generation to neighboring states that are not subject to the Plan which could increase Minnesota air pollution.

Response:

See Section VI.B of the preamble. The EPA's RIA analysis shows minimal amounts of emissions increases in neighboring states to Minnesota. The EPA's final rule air quality modeling demonstrated that Minnesota was not linked in 2026 and so the additional stringency measures for EGUs and non-EGUs are not applied to Minnesota, rendering the above comment moot.

Comments:

Commenter (0350) states, in addition to other general causes, that the limited availability of capable companies to design, manufacture, and install controls for its specific engines makes meeting the 2026 deadline more difficult. The commenter advises a final project completion year of 2046. Commenter argues that the EPA's assumptions are misplaced and insists that the Agency 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.

Response:

See preamble Section V.B and VI.A and the EGU NO_X Mitigation Strategies Final Rule TSD.

Comments:

Commenter (0356) states the proposed initial compliance deadline for non-EGU sectors is not until the 2026 ozone season and suggests that the EPA use the interim time to pursue development of a cross-sector emissions trading mechanism that may reduce the costs of the proposed rule across the entire U.S. economy.

Response:

See preamble Section VI.C.

Comments:

Commenter (0372) states that state budgets reduce ozone season allocations based on emissions rates for combustion modifications for coal-fired units. These rates are unattainable by any type of boiler combusting bituminous coal by a large margin. The 2026 due date is not workable for its facilities. The commenter also states Regional Transmission Organizations require time to process unit deactivations to maintain grid reliability and commissioning replacement generation also requires time. The commenter suggests creating a “safety valve” provision to allow electric generating units to produce electricity to the grid when grid emergencies avail themselves and waiting until there is time for resources to transition to more sustainable energy sources.

Response:

See preamble Section V.B for a discussion on rate performance and timing. See Section VI.B for EPA’s response to reliability comments in this final rule.

Comments:

Commenters (0380, 0405, 0416, 0501) state rule would require non-EGU sources to comply beginning in 2026, but that deadline is not feasible. Instead, commenters advocate for case-by-case reviews for the schedule. At least one commenter (0380) recommends that the EPA use a process similar to the approach used to determine “alternatives” for reasonably available control technology (RACT) for individual sources. Commenter (0380) 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 the 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. Commenter (0416) requests that the rule require compliance on a case-by-case basis in conjunction with state permitting agencies that can assess the practicalities of installing potential multiple control devices across a single steel mill. However, commenter (0416) asserts to the extent the rule includes a set date for compliance (which must be substantially later than 2026), the rule must include a provision whereby a source can request additional time to achieve compliance with the emissions limits based on a demonstrated source-specific need. Commenter (0501) recommends that the EPA not establish a hard cutoff date for submittal of case-by-case extension requests, but instead should judge any such request on the merits of the issues that have arisen, including whether the issues were brought to the EPA’s attention in a timely manner.

Commenter (0395) references a 2022 report prepared for the American Public Power Association (APPA) that reviewed 18 SCR installations, which reported that the typical time necessary for installation on one unit (based on current market conditions) is 75 months. Commenters (0320, 0437) maintain that facilities would need a minimum of four years to implement controls after promulgation of any requirement to do so, because the process to undertake a retrofitting project is complex, involving design, engineering, permitting, procurement, and installation to name only some of the necessary work streams. Commenters (0395, 0437) also mention supply chain issues and COVID-19 impacts, as reasoning that the time necessary to implement construction projects has increased considerably and the proposed timeline is unattainable – *e.g.*, due to current supply chain issues with parts and instrumentation, a CEMS installation would likely take 54 to 60 weeks if a facility was ready to start now.

Response:

See preamble Section VI.B and C. Also, see the EGU NO_X Mitigation Strategies Final Rule TSD.

Comments:

Commenter (0403) note the primary steps include: 1) evaluation of the existing configuration to determine the best engineering solution; 2) conducting engineering design at 30 percent, 60 percent, 90 percent, and subsequent preparation of design engineering drawings for construction; 3) obtaining necessary approvals including required permits to construct from the local or state air permitting agency; 4) acquisition of the emissions control equipment; 5) site preparation and construction; and 6) emissions source testing of the emissions control system to demonstrate compliance with the new emissions limits. And its estimate ranges between 3 and five years. Commenter (0416) describes, in that short time period (three years), iron and steel companies would have numerous detailed and complicated tasks for to complete for at least one or more affected units – *e.g.*, conduct stack tests and other process and emissions studies, then complete detailed engineering evaluations, and after determining appropriate controls, a companies will need to proceed through their capital expenditure or other corporate approval process, which can be time-consuming, procured approved control devices and comply with any applicable air permit, and finally install the control device and conduct a "shake-out" period and any needed calibrations. Commenter (0416) express concerns that such wide-ranging demand on resources all at once may result in possibly steelmaking outages.

Commenters (0405, 0416, 0523) state preparation and submission of a work plan is unnecessary and is otherwise not practical within 180 days of the rule effective date. At least one commenter (0416) states that the EPA should remove the requirement to submit a work plan, which they feel would be duplicative of information likely to be requested through air permits. Furthermore, commenter (0416) states, if a work plan is required, 365 days should be allotted to prepare and submit the plan. Commenter (0523) clarifies that it would take far longer than 180 days to conduct a feasibility study of various potential controls to achieve new emissions limits, select a particular control technology to achieve those limits, solicit bids from vendors, and finalize a construction schedule.

Commenters (0406, 0548) recommend any future rulemaking tied to emissions limits both consider and be connected to planned and/or scheduled controls installation, furnace rebuilds or redesigns at the plant. Commenter (0406) states the 2026 deadline will require glass manufacturers to perform significant maintenance/modification on furnaces that were just rebuilt within the last ten years or conversely have to rebuild/modify furnaces prior to their scheduled rebuild based on age. Commenter (0548) adds that this date does not take into consideration the time necessary to secure required permits, or to develop and finalize the many detailed engineering aspects incorporated into a plant's modifications. Additionally, commenter (0548) claims that the 4.0lb/ton NO_X limit does not take into consideration lower production periods at the glass container plants, where furnace emissions are not increased, but fuel must continue being sent into the furnace, so glass solidification does not occur. It is worth noting, days of lower glass pull have been recognized in recent EPA Consent Decrees, and alternative limitations on emissions have been applied in such instances. Commenters (0406, 0548) recommend that the EPA consider taking a similar approach as San Joaquin Valley Air Pollution Control District Rule 4354 (for glass melting furnaces), for which revisions were finalized in December 2021, that provides compliance deadlines to meet emissions limits that are based in part on furnace rebuild.

Commenter (0411) states the proposed rule does not allow sufficient time for installation and optimization of SCRs, especially for those units that are scheduled to retire in the near term; arguing that it will be a waste of money to invest in retiring units. To illustrate, commenter discusses the retirement of several plants/units, including Sherburne County unit 3 that is scheduled to retire by the end of 2030. Commenter proposes that the that the EPA modify its proposal to (1) Use only one emissions rate based on a historical three-year lookback for a unit retiring where controls have been determined to not be cost recoverable by a state regulatory agency. This rate should remain unchanged for the unit until it retires; and (2) Exempt these units from the backstop provision until controls are installed or when they retire, whichever is sooner.

Response:

See Section VI.a and VI.B of the preamble. The final rule extends the daily backstop rate for units with SCR retrofit potential including Sherburne County Unit 3. In the final rule, the daily backstop rate for units with SCR retrofit potential is extended to no later than 2030, as opposed to 2027 at proposal. Therefore, this rate would only apply during the year in which Sherburne 3 plans to retire; compliance with the allowance holding requirements associated with the daily backstop rate is feasible in this circumstance. Moreover, Minnesota is not linked to any nonattainment or maintenance receptors in 2026 in the final rule modeling, and therefore no SCR retrofit-based emissions reductions or corresponding daily backstop rate reflecting SCR retrofit apply in the state.

Comments:

Commenters (0431, 0533, 0554) state the rule will eliminate the flexibility of the CSAPR trading program by mandating drastic changes within a timeframe of three years; essentially ending the use of trading as a compliance alternative and force technology installation. Commenter (0431) asserts that propose provisions, like the dynamic budget setting process and bank recalibration that minimizes the allowances sources can save, only further limiting flexibility in the program.

Response:

See preamble Section VI.B.

Comments:

Commenter (0433) supports the inclusion of control measures for EGUs and non-EGUs. The commenter also states the 0.6 ppb reductions at impacted Connecticut monitors will not occur until 2026 and it is too late for its 2024 attainment date.

Commenter (0437) suggests that the EPA appears to recognize that its proposed implementation schedule will be challenging because it noted "In addition, the publication of this proposal provides roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning now to be prepared to meet this implementation timetable." However, commenter asserts that few, if any, owners will be willing to commit funds and resources to begin detailed engineering and design given the significant gaps and uncertainties in the rule as proposed, and in the absence of a more thorough technical demonstration that the proposed actions are necessary to satisfy the CAA's good neighbor provisions. At large, commenters (0284, 0320, 0424, 0437, 0518, 0549) recommend that the EPA allow for compliance extensions of more than one year (up to an additional three years was specifically recommend by commenter [0320]) based on a facility-specific demonstration of need. Commenters (0320, 0437) insist that the EPA provide such a mechanism for facilities to request more time to comply. Commenters (0320, 0424, 0437) assert that when accounting for permitting, some facilities may need at least four years to implement such controls. To illustrate the need for extension opportunities, commenter (0518) recalls that the EPA recently approved New York's SIP revision that provides for a two-year extension for newly required NO_X controls.

Commenters (0508, 0782) request an extension of the proposed timeline to May 1, 2027, for non-EGU pipeline sources.

Commenter (0530) supports, in general, the proposed timeline.

Commenter (0758) states the EPA should expand and strengthen its proposed emissions standards for non-EGUs and require reductions from non-EGUs earlier than 2026. The commenter refers to 42 U.S.C. § 7511(a)(1) and suggests the EPA should consider requiring tiering of installation/implementation, such that controls are required at Tier 1 industries sooner than Tier 2 industries. The commenter also states allowing non-EGUs to extend their compliance deadline by a year is unlawful and unwarranted and references 87 Fed. Reg. at 20,104. The EPA must require NO_X reductions by the ozone seasons preceding the downwind 2024 and 2027 attainment deadlines, or by May 2023 and May 2026. Non-EGUs can install the necessary controls by the May 1, 2026, compliance deadline—and in many cases, sooner.

Commenter (0758) also states this rule cannot satisfy the states' obligation to include enforceable emissions limitations in their 2021-2028 SIP revisions. Although the rule proposes to impose a firm, state-level NO_X emissions budget for 2024, that budget will not necessarily ensure the emissions reductions necessary to make reasonable progress toward natural visibility. Moreover, the vast majority of the emissions reductions expected under the proposed rule will not be made enforceable until 2026, when the EPA implements additional emissions budgets commensurate with the reductions achievable with SCR retrofits. The commenter urges the Agency to establish default budgets for 2025 and 2026 in the final rule that would apply were the Agency to fail to complete the dynamic budgeting process for those years, for whatever reason. The EPA suggests that a source commitment to retire by 2028 could "potentially defer" or satisfy this rule's SCR requirements, and also satisfy the Regional Haze Rule's requirements, and this approach is inconsistent with the Regional Haze Rule. Therefore, even with a binding 2028 retirement date, states must evaluate whether there are control measures or upgrades to existing controls that are likely to satisfy reasonable progress during the 2021-2028 planning period.

Response:

The basis for the rule's compliance schedule is in Section VI.A of the preamble. The EGU emissions budget-setting approach is set out in Section VI.B.

Comments:

Commenters (0294, 0301, 0507, 0508, 0518) ask that the EPA to consider (as it did for the approved NY SIP revisions) a timeline beyond the one-year compliance deadline extension. Additionally, the commenters (0508, 0518) urge the Agency to establish a reasonable framework for states and sources to obtain additional time to achieve required deadlines. Commenters briefly describe reasons for why emissions sources would need an additional time to comply, including, for example, to obtain a construction/preconstruction air permit (*e.g.,* PSM/RMP). Commenter (0301) implies that the air permitting process can take longer than 12 months to complete, reflecting a full third of the estimated project timeline of 36-months. Commenter (0507) suggests that the proposed rule fails to acknowledge or consider the work required to achieve compliance, specifically those situations that require PSD or NNSR) analysis and subsequent permitting. The commenter further implies that lengthy permitting requirements may make it difficult or impossible to meet the proposed compliance deadline, placing reliability and meeting delivery obligations in jeopardy – *e.g.,* permitting programs may require the application of BACT or LAER to the facilities further expanding scope, schedule and cost of the emissions control systems. According to the commenter, adding the necessary equipment to comply with the rule at existing facilities may trigger permitting requirements under Section 7 of the Natural Gas Act administered by the FERC – an authorization process that could add up to two years to the schedule. Additionally, commenter (0518) points out that in some cases NSR permits would be required, which are typically multi-year efforts that are routinely appealed, further delaying the ability to commence construction on any reasonable timeline.

Commenter (0507) believes adding the necessary equipment to comply with the rule at existing facilities may trigger permitting requirements under Section 7 of the Natural Gas Act administered by the Federal Energy Regulatory Commission. The authorization process for such a project could add up to two years (with no complicating factors) to the schedule for additional environmental impact reviews. The case-by-case extension process should accommodate such delays as they would be caused by compliance activities and are not within the operator's control.

Commenter (0353) reminds that pipeline operations must be maintained/operated pursuant to private contracts and FERC obligations, which makes it difficult to install controls and/or replace/rebuild stationary engines – in other words, companies cannot simply shutdown operations for extended periods of time. Commenters (0355, 0550) also suggests that the 3-year timeframe (to design, construct, and begin operation of a new SCR at an existing unit/SCR retrofits) is unrealistic and will cause significant adverse economic impacts to Americans from the additional costs of generating electricity under this proposal; health, environmental, and national security impacts that could result from grid volatility, unreliability that would result from premature retirements of fossil fuel EGUs, and the impact of current and ongoing supply chain problems, worker shortages, and inflation on obtaining an installing the required technology.

Commenter (0380) states the proposed rule compliance timeframe is not consistent with the EPAs past decisions, and the market constraints that supported previous EPA decisions have not changed. 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. 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. The commenter also states 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). Finally, the commenter states 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. Commenter references a 2014 report cited by the EPA in the TSD and prepared for the INGAA Foundation, Inc, that contains, for example, a review of the various types and numbers of RICE inventoried, as support.

Commenter (0380) objects to EPA's decision to propose to require over 1,400 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. The commenter states that they operate roughly 260 engines of the 1,400 RICE engines identified and expresses concerns that the proposed rule will lead to higher costs than assumed (upwards to $900,000,000) and significantly lower overall emissions reductions than assumed would be achieved. The commenter argues that the proposed FIP also fails to consider the impact of the proposal on industry's ability to comply with its FERC obligations, and based on past EPA rulemakings only about 75 engines a year can be retrofitted on a sustained basis (within the proposed timeframe), given resource constraints and the time involved in obtaining and installing the required equipment. The commenter concedes that the projection (75 engines per year) is likely an overestimate once supply chain, global market conditions and other impacts from the COVID pandemic are considered. The commenter expands on the comment, claiming that the proposed timeframe (three years) would be infeasible even if only 300 units were affected nationwide – much less the more than 1,400 that actually exist.

Commenter (380) says EPA has not considered the impact of the proposal on the T&S industry's ability to comply with its FERC obligations. The commenter states that because natural gas is a critical resource, FERC requires interstate pipelines to be able to provide maximum capacity at all times. The commenter contends that 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.

Response:

See Preamble Section VI.A and VI.C.

Comments:

Commenter (0798) states the EPA currently subjects states linked only with maintenance receptors to the same 2026 deadline the EPA sets as applicable to states linked to nonattainment receptors, and this is based on an erroneous legal assumption that all compliance must be in place by 2026, when in fact the EPA retains discretion with regard to states that are not linked to any nonattainment receptors. The commenter briefly discusses the Wisconsin v. EPA case and its' findings as support, arguing that the EPA's application of the 2026 deadline to states linked only to improving maintenance receptors (*e.g.,* Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin, Wyoming) is legally erroneous. Furthermore, commenter maintains that the 2026 deadline should not bind states only linked to maintenance areas, or in any case, requirements should be suspended as long as the linked receptors are in attainment, with obligations triggered only if the maintenance receptors slip into nonattainment.

Response:

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).

5.2 Regulatory Requirements for EGUs

5.2.1 Group 3 Trading Program

Comment:

Commenter (0332) supports the use of a trading program for the power sector, consistent with many past actions by EPA. The commenter encourages EPA to continue to utilize "regulatory flexibilities and market-based mechanisms" and notes that since the 1990 CAA amendments, the many flexible compliance regimes promulgated by the Agency have resulted in significant emissions reductions and a marked reduction in unhealthy air quality days, all at lower than predicted costs to industry and customers.

Response:

EPA has considered this comment.

Comments:

Commenter (0541) operates units that are fully controlled with SCRs that EPA has determined would require no further reductions, and yet the commenter would still be responsible to account for and acquire allowances, which will be challenging under the limitations of the trading program.

Commenter (0223) states that it doesn't make sense to allow facilities to buy emission allowances when they already have pollution controls installed. The commenter argues that these facilities should be required to use their already-installed controls by May 2023, as the proposed rule gives them too long to comply. The commenter notes that because the proposed rule is overdue, facilities are only now being required to meet 2015 standards, so the final rule should be as strong as possible and implemented as quickly as possible to make up for lost time.

Commenter (0433) writes that the EPA should sunset emissions trading as a compliance option by 2027 and require NOx controls to be optimized and run on a daily basis, since "ozone precursor emission reductions are required nearer to the time and location of the ozone exceedances they are intended to reduce," especially on hot summer peak electricity demand days when ozone concentrations are the highest. The commenter argues that there is little justification for continuation of a trading program to address ozone transport and adds that cap and trade programs should be designed with EJ communities in mind to assure emission reductions occur in these communities especially on high ozone days. The commenter expresses support for market-based mechanisms, including cap-and-trade programs, but warns that when used to control for local pollutants such as NOx or ozone, such mechanisms must be very carefully designed to ensure that they do not inadvertently contribute to the persistence of concentrated pollution levels in affected communities.

Commenter (0433) discusses the economic impacts of the proposed rule. The policy argument that trading mitigates the cost of controls, especially for sources which are expected to permanently shut down in the near future, must be weighed against the public health costs of long-term nonattainment. Connecticut has borne the cost of nonattainment for over fifty years, and we cannot overlook the economic benefit that has been afforded to sources operating during the last half-century. Moreover, selective catalytic reduction and selective noncatalytic reduction have been required as Best Available Control Technology for new sources since the 1990's. The owner of any source not already equipped with such controls has reaped significant economic benefit while imposing the cost of air pollution on society.

Moreover, based on another EPA proposed rule, Connecticut will soon be bumped up to severe nonattainment in three of its eight counties and required to attain the 2008 ozone standards in 2027, based on monitored air quality data from 2024-26. It is highly plausible Connecticut will not attain by this date, in which event major sources in the nonattainment area will be subject to fees under CAA section 185. These potential fee payers are sources with potential emissions of just 25 tons per year of NOx or VOC, well below the 150-ton threshold of actual NOx emissions now under consideration [see 87 FR 20095]. The CAA section 185 fees currently exceed $10,600 per ton of NOx or VOC. That rate will be adjusted for inflation and by 2027 will undoubtedly exceed the "reasonably" cost effective threshold EPA has set for control of sources for this rule."

Response:

For discussion of the Agency's rationale for using an enhanced trading program as the compliance mechanism for EGUs in this rule instead of generally relying on enforceable emissions limits for individual EGUs, see Section VI.B.1 of the preamble.

5.2.1.1 EGU Applicability

Comments:

Commenter (0428) expresses concerns about the EPA's proposal to expand the CSAPR region spatially, but not in a contiguous manner, "to include fossil-fueled EGUs operating in the Western Interconnection that are not associated with the Texas or Eastern Interconnections." The commenter explains that the emissions trading program proposed in this FIP crosses the separate interconnections' boundaries, even though electricity production and distribution are contained and managed within an interconnection. According to the commenter, the effect of the EPA's proposal is that a ton traded from a fossil-fueled EGU in an affected WESTAR region state to the East or Texas, or vice-versa, would result in air quality changes and operational costs not benefiting the impacted ozone monitoring sites in the West, the East, or Texas, depending on how the traded tons flow, and confuse or cloud EPA's proposed remedy for interstate transport from EGU sources.

Commenter (0505) argues that California EGUs should be included in the proposed trading program. The commenter points to EPA's analysis showing that California EGUs contribute more to downwind monitors in other states than Texas EGUs. The commenter also notes that EPA's data indicate that there are 27 units in California without SCR or SNCR controls, and eight units that exceeded the EPA's proposed emissions limits for 2021. The commenter writes that EPA was incorrect in stating that California had the "highest share of renewable generation among the 26 states examined at Step 3" (87 FR 20088), as the Energy Information Administration's 2020 data (released May 2021) showed Texas generated more power in terawatt-hours from renewable sources.

Response:

See Preamble Section VI.B.5. The assurance levels would remain in place for each state to ensure the reductions are occurring in the upwind state, and the degree to which a state emits beyond its budget through allowance purchase from sources in other regions is ultimately limited by this provision. Moreover, the added enhancements of a daily backstop further ensure the location of in-state cost effective reductions. For discussion of the Agency's finding that there are no additional emissions reductions required to eliminate significant contribution from

EGU sources in California, see Preamble Section V.C.1. With respect to the commenter's assertion that the EPA made an incorrect statement regarding California having a higher share of renewable generation than other states, the commenter is mistaken. The EPA's statement explicitly referred to the relative proportions of various types of generation in a state's overall mix of generation, as indicated by the word "share." The commenter has confused relative proportions with absolute quantities.

Comments:

Commenter (0758) states EPA must strengthen the EGU budgets to reflect emissions rates achievable through the use of the selected controls as soon as practicable, and certainly by the downwind attainment deadlines, or as soon as possible thereafter. The EPA's methodology for calculating the EGU budgets based on optimization of SCR is excessively conservative. The commenter contends that the EPA's proposed EGU dynamic-budget mechanism is well justified and should be improved by accounting for emission reductions from planned retirements and from generation shifting. The commenter (0758) suggests that, to establish budgets that in fact drive the emission reductions associated with EPA's selected control strategy for EGUs, it is critical that the Agency calculate budgets based on achievable emissions rates from each of its selected controls and the earliest possible timing for deployment at the EGUs assumed to use those controls. Furthermore, the commenter adds that, as long as downwind attainment problems persist and upwind states are contributing to these problems above the 1% significance threshold, EPA must expand its EGU control strategy to more types of units and to higher cost thresholds to achieve emission reductions that are needed to eliminate significant contributions to downwind pollution.

Commenter (0558) also states it is inappropriate to provide an exemption for oil/gas steam EGUs based on 3-year average ozone season NOx mass emissions of less than 150 tons/season. The commenter explains that many of the oil/gas steam EGUs that would otherwise be subject to SCR installation emission reductions, except for the 150 ton/season average, tend to operate at high-capacity factors during the days when hot weather increases grid demand and is conducive to high ozone formation downwind. To illustrate, commenter (0558) recalls that for the 2021 ozone season, July 27 was the date of the highest level of EGU NOx mass emissions (AMPD data including electric utility units, cogeneration units, and small power producer units). The commenter describes that on July 27th, the Texas VH Braunig units 1 and 2, both gas-fired steam EGUs with nameplate ratings in excess of 100MW located in a Group 3 state, operated the entire 24 hours of the day. The Braunig unit 1 had a daily NOx mass emissions of 5.67 tons with a daily average NOx rate of 0.3629 lb/MMBTU, but with a peak full load NOx emission rate of 0.6290 lb/MMBTU. The Braunig unit 2 had a daily NOx mass emissions of 3.61 tons with a daily average NOx rate of 0.1917 lb/MMBTU, but with a peak full load NOx emission rate of 0.2430 lb/MMBTU. The commenter recommends that EPA remove the 150 ton/season exemption for oil/gas steam EGUs in the same nameplate rating categories as those proposed for coal fired EGUs by including backstop emission limitations for these units.

Response:

See Preamble Section V.B and the EGU NOx Mitigation Strategies Final Rule TSD for EPA's assessment on which EGU emissions reductions that could be achieved through retrofit of SCR controls constitute significant contribution. EPA notes that the above-mentioned sources are covered under the trading program of the final rule and would face an incentive to reduce emissions based on the allowance holding requirement.

Comments:

Commenters (0558, 0758) urge the EPA to include cogeneration units that are not regulated as non-EGUs in the budgets for the emissions trading program as EGUs. The commenters state that while they can be more efficient than conventional generation, fossil fuel-fired cogeneration units can still emit significant amounts of NOx into the air. According to the commenters, excluding cogeneration units from this FIP could incentivize generation shifting to these units without applicable requirements to limit their NOx emissions, potentially allowing for an increase in total NOx emissions that would not be accounted for in the trading program. Conversely, the commenters state that including cogeneration units in the program could encourage greater reliance on lower-emitting generation resources, as allowances are allocated based on historical heat input rather than presumptive emissions. Commenter (0758) states that the good neighbor provision requires the EPA to prohibit significant contributions to interstate ozone pollution, and the fact that a certain type of unit is more efficient or performs better with regard to NOx emissions than other units should not necessarily qualify all units of that type for exemption from the EGU NOx emissions trading program. The commenter states that any cogeneration units in non-EGU industries regulated by the proposal that do not meet the applicability criteria for the trading program must be regulated as non-EGUs, and any units that meet the applicability criteria for the trading program must be regulated as EGUs.

Commenter (0558) states that the EPA identified nine Delaware units in the proposal's Table VII.B.3-1 and requested comments on whether these specific units meet the applicability criteria for inclusion in the Group 3 trading program. The commenter reports that four of the specified units, located at Christiana and Hay Road, are EGUs with generator nameplate ratings in excess of 25MW. Christiana 11 and 14 are both oil-fired simple cycle combustion turbine generators and each has a nameplate rating of 26MW (EIA listing). Hay Road Units 1 and 2 are dual fuel combustion turbine generators operating in a combined cycle configuration with each having a nameplate rating of 122MW (EIA listing). The commenter states that these four units produce electricity for sale, do not serve in a cogeneration capacity, and meet the criteria for inclusion in the program.

Commenter (0558) states that five additional units that operate as cogeneration units are located at the Delaware City Refinery and may be subject to exclusion if the EPA retains the exemption for cogeneration units. The commenter states that it is critical for EPA to understand the steps that the Delaware has already taken to achieve NOx reductions at this facility. The commenter notes that Delaware reduced NOx emissions through 7 DE Admin. Code 1142, where these units are governed by a facility wide annual NOx cap that has significantly reduced emissions from the facility. The commenter adds that the emissions cap has been reduced from 2,525 tpy to 1,650 tpy through the installation of many NOx control devices at the site, which required extensive investment by the facility and permitting work from the state of Delaware. The commenter notes that the in addition to the annual cap, the unit permits have incorporated short term emission limits requiring the operation of the pollution control devices. The commenter states that incorporating select units into a NOx trading program at this time will likely shift emissions to other units onsite and not result in actual emission reductions and it will also undermine Delaware's authority and the work done to control emissions in the state.

Commenter (0309) relates that the EPA states that it currently lacks sufficient information to determine whether any of the commenter's units listed in Table VII.B.3-1 of the proposal, including five units at the Delaware City Refinery, meet all of the relevant criteria to qualify for an exemption from the Group 3 trading program as a cogeneration unit or a solid waste incineration unit. The commenter provides documentation intended to demonstrate that all five of the refinery's units qualify for exemptions as cogeneration units.

Response:

For discussion of EPA's determination in the final rule regarding coverage of cogeneration units, see Preamble Section V.B.3.c. The comments concerning particular units in Delaware are moot because Delaware is not covered by the final rule. The EPA has made no determination on whether the units at the Delaware City Refinery would qualify for exemptions as cogeneration units under the Group 3 trading program's applicability provisions if Delaware instead were covered by the final rule.

Comment:

Commenter (0758) states that fossil-fueled boilers and turbines that are connected to generating units producing electricity for cryptocurrency mining ("crypto-generators") warrants special attention by the Agency as it finalizes the applicability provisions of this rule. The commenter relays that there is an emerging trend towards transitioning existing fossil-fueled EGUs which are (or would be) covered units under the proposal, to serve as crypto-generators, either by partial or complete removal from service selling electricity to the grid. The commenter states EGUs that have already been retired but are revived to serve as crypto-generators must be treated as covered EGUs under the final rule. The commenter remarks that allowing EGUs that repurpose to cryptogeneration to exit the EGU trading program would exacerbate the lag in the dynamic budgeting process because allowances reflecting these units' historical heat input would continue to be allocated to the EGUs remaining in the trading program for up to two years following the shift to cryptogeneration. These excess allowances, which would no longer be needed by the exiting crypto-generators could compromise the effectiveness of the EGU trading program by significantly weakening the incentive to implement the selected control strategy for EGUs. The commenter also states that the EPA must clarify in the final rule that any EGUs that emerge from retirement or dormancy to serve as crypto-generators will be covered units and will be required to meet the control requirements of the rule applicable to EGUs. Further, the commenter states that EGU owners committing to retire covered units must ensure that those units permanently cease producing electricity (and air pollution) and must not be allowed to withdraw from service as an EGU and be reborn as generators serving cryptocurrency "mines." The commenter asserts that at the very least, where new fossil-fuel boilers or turbines are developed to serve crypto-generation, they must be regulated as industrial boilers and be required to apply SCR. The commenter also mentions that crypto-generators are not cogeneration units and would not be eligible for the exemptions available to certain cogenerators and that crypto-generators do not require additional time beyond that provided for EGUs to comply with the rule.

Response:

EPA finds that the Group 3 trading program's existing applicability provisions will address the concerns that the commenter raises regarding coverage of fossil fuel-fired units to produce electricity for cryptocurrency mining. Under the trading program's applicability criteria, a stationary, fossil fuel-fired boiler or a stationary, fossil fuel-fired combustion turbine serving at any time after January 1, 2005 an electricity generator larger than 25 MW producing electricity for sale is generally covered, unless the unit meets the program's additional criteria to qualify for an exemption as a cogeneration unit or solid waste incineration unit. A unit that would otherwise be covered under these applicability criteria will not become exempt either by ceasing the sale of electricity to the grid or by ceasing operation for a period of time.

5.2.1.2 Budgets and Budgeting Procedures

Comments:

Commenter (0354) writes that the proposed changes to the NOx emission trading program would significantly restrict the number of NOx allowances that would be available, and thus would limit the ability of EGU operators to secure allowances in order to comply with the FIP, particularly if the installation of NOx emission controls has been deemed economically unsupportable. The commenter writes that the establishment of state NOx allowance budgets would eliminate the ability for some sources to overcontrol and generate excess allowances that can be used by other sources.

Commenter (0354) writes that the dynamic budget would unnecessarily restrict the ability of EGU operators to plan for compliance with the FIP in future ozone seasons as well as limit the trading of allowances. The commenter adds that it will also result in additional volatility in the NOx allowances trading market, allowance shortages arising from year-to-year weather variation that impacts renewable availability, and allowance shortages arising from unforeseen outages. The commenter opposes the finalization of the dynamic budget, writing that a static allowance pool is needed to facilitate the allowance trading program, and the EPA should instead rely on future rulemaking to seek further reductions if needed. If the EPA includes dynamic budgeting in the final rule, the commenter suggests that the EPA consider a seasonal assessment in coordination with RTOs and ISOs each time the budget is changed for an ozone season to ensure sufficient NOx allowances are available for that ozone season to help address commenter's concerns regarding year-to-year weather variability reducing electricity generated by renewable resources.

Commenter (0354) explains that the dynamic budgeting process would create the unintended consequence of an EGU maximizing its allowance utilization during the ozone season to limit the ratcheting down in allowances that would occur in future years due to decreased utilization. The commenter proposes that this would lead to an EGU operating when it otherwise would have been offline, generating emissions the proposed rule is intending to reduce.

Commenter (0354) states that the state NOx allowances budgets that would result from the proposed rule may render ongoing operation to be uneconomical for some EGUs and lead to either "unreasonable" pollution control investments for EGUs with limited remaining lives or accelerated EGU retirements, particularly in 2026 and beyond. The commenter explains that either of these outcomes could lead to increased electricity prices, which would be particularly harmful for low-income families. The commenter requests that EPA consider economic equity with respect to this issue in upwind states.

Commenter (0341) writes that setting state budgets based on one control period is inaccurate and improper. The commenter explains that using one control period as the basis for the emission rate does not account for variability in unit operation over varying operating scenarios and other conditions, such as weather, natural disasters, unit outages, fuel prices, economic development, etc. In addition, the commenter states that this penalizes units that have operated below the 0.08 lb/MMBtu NOx emission rate threshold for optimized units. The commenter states that the EPA should consider basing the state ozone season NOx emissions budget on the optimized threshold with the heat input based on the average of the highest three of the last five years for each unit.

Commenter (0341) writes that a dynamic budget is unnecessary and will negatively impact grid reliability by 2025. The commenter states that the proposed dynamic budgeting process arbitrarily ties a state's budget to a single operating year that may not be characteristic of normal EGU operations. The commenter suggests that the EPA contemplate a "safety valve" to address reliability and safety where allocations may not be available so that EGUs can generate electricity under emergency and/or unexpected circumstances.

Commenter (0346) writes that due to EPA's methodology, existing coal-fired generation cannot make up the non-SCR EGU shortfall caused by the proposed rule, and it is unclear how the shortfall will be covered. The commenter explains that the proposed FIP locks in unit capacity factors, based on heat input data from Summer 2021, and dynamic budgeting will force capacity factors downward based on future heat inputs, knowing they cannot ever exceed 2021 levels due to the lack of available allowances.

Commenter (0346) expresses concerns regarding state budgets. The commenter states that the proposed rule would either force companies to install certain technologies or require companies to shift generation to other sources. The commenter states that this because the proposed budgets are so restrictive that allowances will be sold at exorbitant prices or be unavailable altogether. The commenter adds that the State Budget Setting process also is flawed in that it does not accurately represent the generating unit profile for many states. For instance, the Base Case does not properly represent the generating unit profile in Texas because over half of the coal fleet in ERCOT alone is incorrectly presumed as retired or idled. In addition, the commenter asserts that the EPA incorrectly assumes that cooperatives can freely transfer generation to different cooperative service areas, and the EPA's failure to consider transmission constraints is a serious flaw in the proposed budgeting scheme. According to the commenter, if implemented as proposed, the rule will adversely impact cooperatives' ability to meet electricity demand. The commenter adds that a potentially urgent reliability risk presented by the budgets in the proposed rule is the inadequacy of allowance budgets to allow critically needed units to dispatch. The commenter cites NRECA's comments showing that allowance allocations in 2023 will be inadequate for a wide range of units across several states.

Commenter (0372) writes that EPA should adopt the Optimized Baseline values identified by NRECA's technical experts for Kentucky as the final state budget numbers and recalculate the remaining state budgets accordingly. The commenter also states that the EPA should not adopt the new CSAPR Design Concepts. The commenter notes that in response to past commenters claiming that a trading program will not lower emissions on high ozone days, the EPA identified data showing that the majority of EGU operators are choosing not to operate SCR controls. The commenter states that data from 2017 showed that the 274 SCR-controlled units were operating at an average emission rate of 0.088 lb/MMBtu. The commenter notes that in the proposed rule, EPA recognizes that past studies showed a lack of evidence of SCR non-operation but claims that "this problem could become more prevalent in future years relevant to this action", although the proposed rule provides no basis for this statement.

Commenter (0492) supports the EPA's proposal to utilize dynamic budgeting to ensure future state budgets reflect up-to-date fleet composition and heat input data. The commenter explains that the use of Notices of Data Availability (NODAs) to implement EPA's proposed dynamic budgeting mechanism is consistent with the agency's use of periodic ministerial actions in other contexts, such as the established process for calculating and announcing unit-level allowance allocations from new unit set-asides (NUSAs). The commenter adds that in other contexts, a similar mechanism has been employed to issue allowance allocations for the production and consumption of hydrofluorocarbons under the 2020 American Innovation and Manufacturing [AIM] Act.

Commenter (0546) writes that prior to issuing a final rule, the EPA should implement options to add additional flexibility to state budgets and/or to other aspects of the trading program to ensure sufficient allowance availability to accommodate the potential dispatch of higher-emitting units at greater-than-anticipated levels during the ozone season to maintain the reliability of the bulk electric system. The commenter suggests the following options:

- Revised and more flexible state emission budgets,
- Revised budget-setting assumptions for the proposed dynamic budgeting framework with respect to units with limited RULs,
- Modification of the proposed dynamic budgeting approach to consider multiple years of historical operating and emissions data rather than a single historical year,
- Extending the period in which retired units would continue to be included in the calculation of state emission budgets and subsequent unit-level allocations,
- Elimination of the proposed allowance bank recalibration process,
- Revision to or postponement of the applicability of the proposed allowance bank recalibration process, or
- Provide other flexibilities which align with the underlying obligations imposed by Section 110(a)(2)(D)(i)(I) of the CAA.

Commenter (0557) states that the proposal does not provide enough NOx allocations in state budgets to meet summer demands beginning as early as 2024 even for units operating their installed state-of-the-art SCRs. The commenter explains that the only way to comply will be to reduce generation at SCR-equipped units to lower capacity factors or purchase of allowances at exorbitant prices. According to the commenter, losses in Virginia's generating capacity without replacements will stress the grid during peak demand in summer. The commenter states that the EPA should consider the time necessary to obtain RTO approvals for deactivations and for adding new generation assets to replace lost capacity. The commenter also urges the EPA to correct errors in the state budget engineering-based platform and recalculate the budgets so that units can receive enough allocations to cover emissions with assumptions of 0.08 lbs/mmBTU and heat input at 2021 base case (with a growth factor).

Commenter (0348) states that it is critical that EPA clearly explain how generation shifting and dynamic budgeting are executed, and EPA's reliance on generation shifting and dynamic budgeting and as a control mechanism is arbitrary and capricious and presents grid reliability issues.

Commenter (0348) criticizes EPA's assignment of certain idling and generation shifting assumptions to state budgets as being flawed. The commenter writes that the EPA has little experience or statutory jurisdiction to manage the dispatch of power through an emissions reduction program. The commenter references Wisconsin v. EPA, writing:

"[P]etitioners asserted that the agency use of the IPM model assumed an unrealistic number of imminent unit retirements and circumstances of idling. The court found in the appellate review of the CSAPR rule, EPA had not improperly allowed idling to impact state budget development. Accordingly, the IPM model may not be used to accurately project the flow of short-run supply. Management of generation dispatch, whether shifting or idling, are electric power dispatch issues best left to the jurisdictions of FERC and the states."

Commenter (0533) argues that the point of a cap-and-trade program is that the affected sources can choose the most cost-effective units to overcontrol and allow expensive or technologically infeasible units to operate with lesser or no controls while meeting the overall state emissions cap. According to the commenter, if the EPA sets the state budgets based on the stringent emission rates it has proposed and ignores individual circumstances at EGUs that may make achieving such emission rates infeasible, they will eliminate the very mechanism that makes trading programs an efficient method of achieving the most cost-effective emission reductions.

Commenter (0531) writes that the proposed rule deviates from the budget setting process that was approved under EME Homer City and will result in over-control. The commenter states that the EPA errs by not setting budget allocations based on a uniform control cost level and by eliminating units it believes will retire from the budgeting process.

Commenter (0531) states that the proposed dynamic budgeting process will result in over-control and unachievable state budgets. The commenter explains that the EPA's dynamic budgeting process weights the performance of one year too much in setting the year-to-year state budgets and it should be set by looking at the most recent 5 years of available data. The commenter also suggests using the highest 3 years and averaging them, as currently proposed for the unit-by-unit allocations. The commenter states that this new heat input value would then be multiplied by the assumed emission rate based on the existing or required equipment for each unit, and this new number would then serve as the unit allocations for the year of interest, and the state budget would be determined by summing those values together. According to the commenter, there would be no need to do a second step to reallocate the state number to the individual units based on heat input fractions and each unit would be treated fairly based on achievable emission rates. The commenter notes that, as currently written, the proposed methodology for determining the state budget considers the achievable emission rates on the units while the unit-by-unit allocation does not. The commenter also states that the method used to determine unit by unit allocations is inappropriate, as dividing allocations solely by heat input uses an invalid underlying assumption that all units emit at the same rate and will give more allowances than needed to highly controlled units and less allowances than needed to less controlled units. The commenter states that the methodology to determine the state budget and the unit-by-unit allocations should be consistent.

Commenter (0531) argues that the dynamic budgeting system creates a potential for a significant downward spiral in a unit's ability to generate electricity if it is determined an SCR is not an economical feasible option for the unit. The commenter explains that many units will reduce generation/heat input to stay under the given allowance threshold rather than install an SCR system, which due to the nature of the dynamic budgeting process, will eventually require units to cease operation by receiving fewer and fewer allowances and impacting the ability to produce electricity. The commenter states that the dynamic budgeting system also creates issues for units that do install SCR catalyst. According to the commenter, the proposed budgeting process fails to consider unit specific conditions that may require a unit to reduce heat input in a historical year, resulting in a subsequent reduction in state budgets for a future year. The commenter also states that the continual reduction of state budgets will make it more difficult for units with SCR systems to increase heat input/MW output to accommodate the electrical grid due to the reduction of heat input/MW load from units without SCR systems. The commenter states that units with SCR systems will likely find it isn't economical to exceed a historical year's heat input due to the high allowance prices.

The commenter believes the proposed NOx emission rate of 0.05 lb/mmBtu for new SCR systems should be reconsidered. The commenter states that this rate fails to consider what happens to an SCR system as it ages and the costs associated with maintaining the SCR system to continue to achieve a NOx emission rate of 0.05 lb/mmBtu. The commenter also believes the proposed rate fails to consider that units will have to run under the 0.05 lb/mmBtu rate to accommodate for system upsets, startups, and shutdowns. According to the commenter, it is unreasonable to force new SCR installations to achieve a lower NOx emission rate than existing units, as SCR system performance degrades over time, and it will be difficult for new systems to sustain a 0.05 lb/mmBtu NOx emission rate.

The commenter adds that the proposed FIP will significantly increase the cost of producing electricity, which will ultimately be passed through some utilities to the consumer. The commenter notes that the increased costs will come from capital cost of installation and increased maintenance and operation cost to maintain/operate an SCR system. The commenter also remarks that some utilities will likely retire units early due to the economic impacts of this rule, adding more pressure to an already struggling electrical grid in many portions of country.

Commenter (0539) states their belief that a functioning allowance market is absolutely critical for this proposed FIP to succeed; however, they express concerns over the timing of enhancements, specifically "dynamic budgeting," proposed to begin in 2025. The commenter contends that the ratcheting down of allowances to an uncertain amount from one year to the next (i.e., dynamic budgeting) is not an established cap-and-trade type of market mechanism and warns that the proposed dynamic budgeting approach will not allow enough time for utilities to plan and respond to ensure they will have adequate allowances, and may result in unexpected non-compliance events at individual units that cannot be reasonably anticipated. The commenter stresses that utilities need more certainty in a market-based system to allow for thoughtful and deliberate resource planning and facility operations. The commenter recommends that the EPA conduct separate, independent rulemaking to establish new budgets for those 2025-onward years. The commenter says that if the EPA is proposing dynamic budgeting because it cannot accurately establish future year allocations within this proposed FIP, it is unreasonable to expect utilities to be able to plan for future operations based on speculative available allowances.

In a similar comment, commenter (0515) warns that dynamic budgets may contribute to heightened volatility in the allowance trading market, because year-to-year changes to the state allowance budget would create year-to-year uncertainty. As an example, the commenter notes that over the past three months, prices for Group 3 allowances have surged from approximately $6,500 to over $27,000 per allowance, a result of an increased demand as operators acquire allowances to address their actual 2021 ozone-season emissions, and increased uncertainty created by the impact of this very rulemaking. In contract, according to the commenter, using multi-year budgets would reduce volatility by mirroring the long-investment time horizons that are prevalent in the power generation sector, and allow for operators of individual EGU units to engage in long-term resource planning. The commenter further notes that by promoting long-term operational planning throughout the industry, multi-year budgets would, for example, help stabilize the demand for market allowances. The commenter suggests that operators might support declining, more stringent state allowance budgets, if those budgets promoted market stability and long-term resource planning.

Commenter (0348) writes that EPA's proposed dynamic budgeting does not align with grid reliability practices and will undermine grid reliability as it does not appear to allow RTOs or ISOs to respond to emergency needs as they arise. The commenter requests a technical analysis of this aspect of the proposed rule as well as a more adequate and transparent description of generation shifting, and the steps and data referenced in the technical comments.

Commenters (0215, 0259, 0402, 0503, 0510, 0530) support new NOx emissions budgets and dynamic approach taken/adjustments made to these budgets. Commenter (0259) supports updating budgets to account for new retirements, new units, and changing operation. Commenter (0503) notes that on multiple occasions, they have raised concerns that as the cost of allowances decreases, units are incentivized to buy cheaper allowances rather than optimize controls, which undercuts the purpose of the program. The commenter believes that adjusting the NOx emissions budgets each ozone season in response to fleet changes reasonably prevents emissions allocations from sources which subsequently retire or make significant changes to their operating conditions from flooding the market. The commenter contends that this is a fair and equitable practice that ensures continued optimization of emissions controls. Commenter (0279) states dynamic budget updates and restrictions on allowance banking are necessary.

Other commenters (0272, 0282, 0332, 0515) state that the uncertainty in the first year of a new program is often reflected in higher emissions allowance prices and less market liquidity. According to the commenters, by adjusting the allowance budget annually, the market will be in a constant state of flux, leading to concerns about allowance price and availability. Adjusting a budget based on only a single year of operating data may not accurately reflect a unit's operation (*i.e.,* forced outage) and may result in a non-representative allowance allocation. The commenters suggest implementing dynamic budgeting using a multiyear lookback period (*i.e.,* three-year average) to determine past performance more accurately and to freeze the budget for three years once an adjustment is made. Commenter (0515) also states EPA should clarify its annual variability limits.

Commenter (0355) believes that the EPA's proposed dynamic approach to establishing state NOx budgets for the 2025 ozone season and beyond is likely to create ongoing uncertainty regarding allowance availability. The commenter adds that they believe that the EPA's proposed dynamic budgeting approach would serve to significantly limit potential sources of surplus NOx emission allowances in 2026 and beyond.

Commenter (0332) states that dynamic budgeting mechanisms could increase the stringency of the program's overall requirements without justification, which might be inconsistent with the D.C. Circuit's opinion in Wisconsin. As EPA notes, the Agency's proposed budgets are intended to satisfy the court's mandate that the Agency provide a full remedy for interstate transport requirements under CAA section 110(a)(2)(d)(I)(i). However, according to the commenter, the proposed dynamic budgeting goes beyond the full remedy budgets proposed by EPA, and by continuing in perpetuity, prompts the removal of allowances beyond what EPA has technically determined to be a "full remedy" for transport obligations.

Commenter (0359) states dynamic approach proposed to begin in 2025 does not provide certainty beyond the next year for the allocation of allowances. The commenter contends that this approach could artificially establish budgets that are incorrect based on market fluctuations and conditions, such as lower cost to operate a natural gas fired unit when the price of natural gas is low or a lower cost to operate a coal-fired unit when the price of natural gas is high, and the cost of coal is lower. It is also problematic as it relates to how new unit set aside (NUSA) allowances are determined and will reduce the amount of NUSA allowances. This could deter future development in states subject to this FIP, which further places these states at an economic competitive disadvantage to states where the proposed rule would not apply.

Commenter (0519) suggests that EPA's dynamic budgeting approach will continuously ratchet down emissions budgets, effectively mandating greater emissions reductions over time. The commenter explains that this approach revises budgets in only one direction-the state budget cannot increase based on higher annual operations, but lower annual operations can lower the budget. In a typical year, the commenter notes that unit-level operations can be highly variable based on a variety of considerations, such as outages, market needs, reliability needs, the number of startups, and the effect of renewables, and that EPA' s approach to calculating emissions budgets means that one year of lower operations for a unit would permanently lower the state budget. The commenter notes that the EPA has not assessed whether this approach would thereby require states to eliminate emissions in excess of BP A's significance threshold.

Commenter (0519) states that, apart from the risk of overcontrol associated with EPA's dynamic budgeting process, this process also deprives the public of a reasonable opportunity to meaningfully comment on EPA' s future state- and unit-level NOx budgets, in contravention of APA's rulemaking requirements. The commenter adds that, as emphasized by the D.C. Circuit, "the notice required by the APA ... must disclose in detail the thinking that has animated the form of a proposed rule and the data upon which that rule is based." Further, "the opportunity to comment is meaningless unless the agency responds to significant points raised by the public." In contrast to the specific, preset emissions budgets for the 2023 and 2024 control periods outlined in EPA's Proposed FIP, EPA's dynamic budgeting process means that EPA can only provide "illustrative examples" of budgets for 2025 and 2026 in its Proposed FIP. The commenter notes that the EPA characterizes its budget adjustments as "ministerial actions," providing only limited opportunity for the public "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." However, these budgets have significant practical consequences for covered entities that extend beyond mere administrative concerns with data corrections. For instance, they add that the EPA's adjusted budgets would impact state variability limits, which create a risk of substantial penalties for units contributing to exceedances, and the size of the total allowance bank, which limits the compliance options available for EGUs. According to the commenter, depriving the public of an adequate opportunity to provide input on EPA's future emissions budgets violates the APA's rulemaking process and exceeds EPA's rulemaking authority.

Commenter (0286) states Dynamic Budget Setting and Recalibration are flawed and punitive to small sources. Larger utilities may shift generation to different facilities the smaller sources will not have such options.

Commenter (0289) states dynamic budget discourages units from retiring even if they have hit the end of their useful life because with these new requirements, they will almost immediately lose any allowances for that unit that the facility would have received. The commenter notes that it may inadvertently incentivize units to run more and longer than they would do otherwise, if not for this proposed provision. Further, they add that this provision penalizes units for planned routine down-time for maintenance and other security reasons that are needed to ensure major unplanned downtime for a critical unit does not occur. The commenter is concerned that this provision would incentive delaying maintenance in some situations and potentially put the reliability of the electricity grid at risk.

Commenter (0290) states using emissions data from a single ozone season as the starting point to establish Group 3 budgets may not account for potential market conditions that affect individual unit operation, dispatch, and emissions. The commenter suggests that failing to account for market conditions could result in an artificially low starting point for one or more of 25 affected states. The commenter adds that decreased seasonal demand associated with the COVID-19 pandemic and anomalous weather conditions had a significant impact on dispatch of power plants in some states.

Commenter (0300) states due to unpredictable weather patterns in a given year and the resulting demand for electricity, it is inappropriate to set EGU budgets based on a single year of operating data. The commenter believes that dynamic budgeting removes power companies' ability to effectively dispatch units in the most cost-effective way by annually limiting future year states' budgets. The commenter contends that EPA's proposed elimination of allowances for units that have been idled or suspended for two years in a row will inevitably cause power companies to dispatch units simply for the assurance that they will not lose allowances during EPA's reestablishment of states' annual NOx budgets; adding EPA further removes fleet management flexibilities by annually limiting the number of banked allowances beginning with the 2024 ozone season.

Commenter (0323) asserts that the EPA's State Budget Setting Process under the proposed Transport Rule contains numerous errors and omissions and adopts incorrect assumptions pertaining to technology deployment and NOx emission rates. The commenter provides several examples of budget concerns illustrated by nine states within the 25-state Transport Rule region as proposed in the Cichanowicz, Marchetti, Hein and Rivera Report. These states - Arkansas, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Texas, West Virginia and Wyoming – represent different geographic sectors of the Transport Region. The commenter notes that these states also represent various RTOs and different utility structures (IOUs, Public Power and Cooperatives).

Comment (0323) contends that the EPA's Budget Setting Process did not accurately reflect natural gas conversions in the nine-state study region. They suggest that EPA either did not correctly identify the timing of a natural gas conversion or utilize the appropriate post-conversion emission rate in the State Budget Setting process. Table 17 (Natural Conversions in the Nine State Area) of the commenter's letter lists units for which conversion to natural gas is planned for which EPA needs to adjust the timing or emission rates in the State Budget Setting process.

According to the commenter (0323), EPA also incorrectly assumes several unit retirement dates which significantly affect a state budget. Table 18 (Retirement Date Changes in the Nine State Study Area) of the commenter's letter lists corrections required to remedy errors in retirement dates.

Commenter (0323) notes that, as discussed within these comments, the timing for installation of Combustion Controls and SCR processes should be revised to determine state budgets in 2023 and 2026. Specifically, the commenter explains that Combustion Controls require on average 22 months from project inception to commercial operation, and thus will not be available for the 2023 Ozone Season (see Section 4.5). According to the commenter, the earliest time for which Combustion Controls could be operational is the 2024 Ozone Season, which they state is consistent with the language in the proposal that says state-of-the-art combustion controls are to be readily available at the start of the 2024 ozone season. The commenter notes that this is contrary to how EPA established the 2023 state budgets, which assumed the availability of combustion controls in 2023. New SCR retrofits will require 40 months on average, and thus will not be broadly available until the 2027 Ozone Season (per information from 18 SCR installations reported in Section 5.3). In calculating the state budgets for 2023, the commenter recommends that the EPA revise its methodology and not presume Combustion Controls will be operating until the 2024 Ozone Season, and SCR will not be broadly available until the 2027 Ozone Season.

In addition to issues related to the calculation of state budgets, commenter (0323) provides that the EPA has incorporated in Appendix A of the Ozone Transport Policy Analysis Proposed Rule TSD each units' gross generation and generating capacity, and computed capacity factors. Although the description of Appendix A material is incomplete, the commenter notes that it appears capacity values are reported on the basis of summer net, implying an appropriate capacity factor requires knowledge of net and not gross generation. The commenter reports that the commenter's contractors Cichanowicz, Marchetti, Hein and Rivera Report were not able to reproduce capacity factors listed in Appendix A. According to the commenter, the inability to corroborate EPA's calculations creates concerns Appendix A data does not correctly establish the threshold NOx emission rate of 150 tons per year that determines if oil/gas-fired units are required to deploy SCR.

Commenter (0323) recommends that, based upon issues and omissions identified, EPA adjust the state budgets beginning with budget year 2023. The commenter suggests that the focus of these adjustments reflect: (i) the timing for installation of Combustion Controls in 2024 and retrofit SCRs in 2027; and (ii) the correct technology inventory, and (iii) accurate NOx emission rates and retirements.

Commenter (0323) reports that a recalculation of the budgets for the nine example states based upon the information described previously for the years 2023 and 2026 was executed for these comments. Table 21 (Recalculated State Optimized Baselines: 2023 and 2026) of the commenter's letter compares the Optimized Baseline developed by EPA in the proposal to a Recalculated Optimized Baseline. The Optimized Baseline consists of retirements, natural gas conversions, and new SCR processes installed prior to the budget year, plus adjustments to the baseline from SCR and SNCR Optimization and Combustion Controls.

Commenter (0323) notes that utility owners could either be retiring or cease burning coal at 27 non-SCR-equipped coal units between 2026 and 2030, representing 16.7 GW of capacity. The commenter recommends that these units be exempted from the Backstop Emission Rate of 0.14 lbs/MBtu. The commenter explains that since there will be no NOx emissions when they retire, for budget setting purposes their emission rate for the 2026 thru 2030 budget years should be set at 0.14 lbs/MBtu 2021 Baseline. The State Budget Setting process employs data at one point in time - 2021 –to project state budgets for 2023 and 2024. According to the commenter, this approach is flawed as future electric utility operations based upon one historical year will not represent volatility in fuel prices and demand. The commenter states that this static approach does not account for changing dispatch conditions and unit performance, specifically changes in load. Also, the commenter adds that this static approach commits units to a specific capacity factor for state budget purposes. The commenter recommends that the EPA consider an alternative approach that consider changes in demand in computing individual state budgets. In conclusion, the commenter asserts that the budget calculations and emission allocation are in error and must be corrected as arbitrary and capricious actions by the agency.

Commenter (0326) states dynamic budgeting may constitute over-control because it requires reductions beyond the amounts that are necessary to address interstate transport. In the case of Tennessee, the commenter notes that the NOx emissions in 2021 emissions were about 300 tons higher than 2020, but if dynamic budgeting had been in place, EPA would not have issued sufficient allowances to cover the additional heat input. To some extent, the commenter explains that EGUs can address the increased heat input by purchasing allowances, but other provisions of the trading program, such as restrictions on the number of banked allowances and more stringent assurance provisions, will make the purchase of allowances more difficult. Allowances may be difficult to recover after a single year of low heat input (e. g., an economic downturn or reduced consumption due to high energy prices), and the rule could disincentivize electricity production over the long term.

Commenter (0336) states setting the budget for any state, and therefore the allocations that may be parceled out to units in that particular state, on one year's worth of heat input data may not account for variability in heat input at specific units due to significant changes in fuel costs (generated by global pandemic impacts, civil unrest in other countries, extreme weather impacts, and many other factors). The commenter explains that if a state's budget is set using heat input from a year where natural gas prices were abnormally low, but the cost of natural gas increased significantly in the year where that budget was applicable so that more coal was burned, the budget for that state, regardless of what controlled NOx rates are assumed for each unit, would be artificially lower than needed. The commenter recommends that EPA consider using an average of more than one year's worth of heat input data for operating units when calculating state budgets to ameliorate the year-to-year impacts of fuel cost changes.

Commenter (0344) states EPA indicates that using the dynamic budgeting process will allow EPA to account for future changes to the electric fleet, the use of a limited data set to establish budgets/allocations is problematic and doesn't adequately capture long-term variability, especially with regard to major temperature fluxes (below average summer, versus above average summer, versus extremely above average summer temperatures).

Commenter (0366) states EPA's rationale for the Dynamic Budgeting Approach is based on the flawed reasoning that previous trading systems produced "extra" allowances. The commenter notes that the EPA appropriately considered known shutdowns, fleet turnovers, and generational shifts in defining significant contribution and determining budget allocations in 2023 and 2024 which had the effect of reducing the amount of emissions reductions required to remove significant contributions. The commenter states that EPA premises its dynamic budgeting proposal on the thought shutdowns, fleet turnover, and generational shifts would result in an over-abundance of allowances which is undesirable because it would reduce the need for some affected emissions units to run emissions controls to meet state emissions budgets. According to the commenter, the EPA has not provided a justification for excluding these verifiable emissions reductions from future year compliance demonstrations (via retaining the emissions reductions as available allowances and not subtracting them from state budgets), and preferring emissions reductions that come at a higher ongoing cost. The commenter also states EPA's proportional allocation under its dynamic budget system could leave peaking units without sufficient allocations or allowances to meet mandated testing.

The commenter (0366) provides the following support for their position:

First, the commenter (0366) states that under prior trading programs, EPA designed the budget and allowance system as a closed system that in total addressed significant contributions. In this sense, nothing in the system is "extra" as the system as a whole achieves the required emissions reductions irrespective of the level of emissions control achieved on any individual affected unit. Even if such a closed trading system could generate "extra" allowances, as EPA designed the system, the availability of these "extra" allowances to existing units is short-lived as the allowances move from the existing unit allowance system to the new emissions set-aside after a specified number of control periods. Moreover, here, the commenter notes that the EPA also proposes unit-specific backstop daily emissions rates for coal-fired units to assure a minimum level of emissions control — which reduces the likelihood that "extra" allowances could be generated. While the commenter disagrees that the identified allowances are "extra" in the budget system, to the extent that EPA believes this is an issue, EPA has not explained why the backstop enhancement to the existing trading programs is not sufficient to address the issue without need for dynamic budgeting. Indeed, the commenter provides that the State of Maryland offered a similar solution to the issue by providing minimum control levels tailored to such variables as summertime temperature.

Second, the commenter (0366) states that, assuring the stringency of emissions controls and "improv[ing] emissions performance at individual emissions units over time" is not the purpose of the emissions allowance or budget program, nor is it the purpose of the FIP, Generally, the commenter explains that the FIP's purpose is to reduce a state's significant contribution to downwind nonattainment and interference of maintenance in maintenance areas, while the emissions budget approach provides a mechanism for doing so cost-effectively. In context of the proposed rule, EPA uses the stringency of emissions controls to define significant contribution in Step 3 of EPA's multi-factor approach, but the emissions controls themselves are not the significant contribution — significant contribution is a set quantity of necessary emissions reductions. The state budget is allowable emissions remaining after subtracting those emissions reductions. Thus, as defined in the proposed rule, significant contribution is not a moving target; it is a set amount of emissions reductions defined relative to a 2016 emissions baseline projected forwarded to 2023, 2026, and 2032.

According to the commenter (0366), if affected emission unit A in a state permanently operates less, shuts down, or repowers with an alternative energy source, the resulting emissions reductions permanently reduce the amount of emissions from the state.

Commenters (0372, 0409, 0431) state relying on one ozone season will generate inconsistent results; maintaining a generation mix is essential to grid reliability; using one ozone season to reduce state budgets is inconsistent with prior CSAPR methodology; dynamic budgeting is not necessary because the CSAPR framework presently has concepts to address changes in the EGU fleet. Program stringency will be maintained without dynamic budgeting; emissions reductions from dynamic budgeting are not necessary to attain or maintain NAAQS in downwind states.

Commenter (0329) states EPA must expand the NOx allowance budgets. The allowance markets are clearly overtight, making it difficult and expensive for utilities to run needed EGUs while remaining in compliance. Without certainty that credits will remain available, utilities may be forced to not operate units during ozone season.

Commenter (0411, 0544) suggests that EPA's cost assumptions are inconsistent with current market conditions; noting current cost of procuring 2022 vintage Group 3 seasonal NOx allowances in the marketplace is $32,500 per ton, over eighteen times higher than what is assumed in estimating the 2023 cost of compliance in the RIA. Commenter (0544) adds that a source with an optimized SCR that exceeds the Daily Backstop Limit because of a SSM event will be required to comply with the 3-for-1 allowance surrender penalty, meaning that unit will incur costs of $97,500 per ton or more for an SSM event outside of its control. The commenter states their belief that the RIA assumption that a unit will sell any allowances it has in exceedance of what is necessary to cover its emissions is flawed. According to the commenter, EPA assumes a perfectly liquid market that is disconnected from the reality of the current seasonal NOx allowance marketplace; adding that in reality, many allowance holders have policies to never sell allowances even if they are surplus (i.e., allowance allocation is greater than compliance year obligations). The commenter explains that while these allowances may appear to be available in the allowance bank, they are not in fact available for purchase. The commenter highlights the point that in other cases, units subject to New Source Review consent decrees are almost always legally prohibited from selling, trading, or transferring certain NOx allowances – i.e., the allowance market is more constricted than it appears, which reduces the supply of allowances that are available in the marketplace and in turn drives up the price of allowances even further due to scarcity. The commenter adds that recent allowance prices have demonstrated transactions at $32,500 per ton (and higher). According to commenter, if the cost of allowances is assumed to be equal to $1,800 per ton in 2023 than the proposed FIP grossly underestimates the cost of allowances and the overall cost of compliance.

Commenter (0330) states that the dynamic allowance allocations will likely result in over-control with respect to elimination of downwind nonattainment. Historically, the commenter notes that, under the fixed budgets associated with previous CSAPR Programs, the budget for future years is set at the time of rulemaking and serves as a static cap for new and existing units. With dynamic budgeting (discussed in section 5.2.1.2 of this document) and an expectation of an increasing level of renewables the commenter suggests that replacing historic fossil fuel generation, the effective cap is likely to continuously shrink, resulting in emissions reductions to the extent that a given state may no longer result in a significant contribution to downwind nonattainment. According to the commenter, such overcontrol is impermissible under well-established law; please see the comments of the Power Generators Air Coalition in this regard.

Commenter (0355) states that the EPA's proposed approach to presume Selective Catalytic Reduction (SCR) retrofits for the purpose of setting state emission budgets for 2026 and beyond, coupled with other aspects of EPA's proposal, such as the dynamic budget, would result in no obvious sustainable source of surplus allowances. The commenter argues that this makes it difficult to envision any scenario in which a unit, which has been identified by EPA for an SCR retrofit, could operate during the 2026 ozone season or beyond without a major capital investment in NOx emission controls, even if such an investment might only be useful for a handful of years due to the limited remaining lives of the units.

Further, the commenter (0355) contends that, even if sufficient allowances are available, they are likely to be very expensive. Current NOx emission allowance prices for units located in Louisiana and other "Group 3" states exceed $25,000 per allowance, without considering the further allowance reductions proposed by EPA here. According to the commenter, the combination of the restrictive state emission budgets and other flexibility-limiting provisions of the proposal, as well as the likely high cost of allowances, will make it very challenging for a unit to operate in the 2026 ozone season and beyond without a NOx emission control retrofit.

Commenter (0521) states that the EPA should champion those utilities that have installed and operated BACT for NOx reductions, rather than implement new provisions that are punitive in nature, reduces the State's seasonal budgets, and implements command-and-control measures that are counter to the Program's original intent. The commenter notes that as proposed, Missouri's allocations are cut in half from current levels, severely penalizing the entire state, including good actors.

Commenter (0302) states due to the budget setting process outlined in which EPA uses a single year to determine state budgets, Northeast Generating stations (ORIS ID 2081) units 13 and 14 were not allocated emissions even though they operated every ozone season except for 2021. The EPA should evaluate the emissions allocation process to make sure all units are allocated their equitable share of the state budgets.

Response:

See Preamble Section VI.B.4 for discussion of the final rule's state emissions budgets and approach to budget-setting, including responses to comments.

See also Preamble Section V.B.1.e and the EGU NOx Mitigation Strategies Final Rule TSD for a discussion on new SCR performance rate

See also Preamble Section VI.B.1.d for additional discussion of changes made in the final rule to address several concerns raised in the above comments. This includes using a multi-year baseline for dynamic budget, changing the start-date for the daily backstop rate for units with SCR retrofit potential, adjusting the timing and level of the bank recalibration, and phasing in the SCR related reductions across 2026-2027.

EPA disagrees that the dynamic budget would create an incentive for units to operate more in order to achieve a higher allowance allocation. The EPA notes that unit-level allocations are distributed through a separate methodology, and greater heat input or emissions at a given source wouldn't inherently mean more allocations for that same unit. Moreover, even in the event that more utilization manifested itself in more unit-level allocations, that would not make a high emitting source better off. The higher emitting sources, on average, receive an allocation that covers a smaller share of their emissions relative to lower emitting sources. Therefore, if a poorly-controlled source was to increase its operation, it likely would be increasing its shortage of allowances, because any increase in allocation would not keep pace with its increase in allowances owed to cover the extra emissions.

In regard to comment that EPA's proportional allocation under its dynamic budget system could leave peaking units without sufficient allocations or allowances to meet mandated testing, EPA notes it is using the same methodology as prior rules (with small adjustments that would only increase allowances for these peaking units), sources are not limited to their initial allocation, and these units have had no such problem with testing under prior rule allocation schemes. See Preamble Section VI.B.9 for discussion of the allocation methodology. The EPA disagrees with speculation that allowances will be unavailable for purchase and notes that such speculation is contradicted by decades of historical experience with previous trading programs.

In regards to capacity factors listed in Appendix A of the Ozone Transport Policy Analysis Proposed Rule TSD, they have no bearing on the state budget calculations and are informational only. In these instances, they reflect the reported heat input for the season divided by the product of the total reported maximum hour heat capacity multiplied by the number of hours in the ozone season. Similar values could be derived using total seasonal generation divided by the product of unit capacity multiplied by the number of hours in the ozone season.

In regard to unit-level retirement dates, EPA made unit-level changes reflecting comments. The results are reflected in both the NEEDS and Engineering Analytics File. A record of the changes can be found in the file titled "Unit-Specific Comment Log" available in the docket for this action.

In regard to comments suggesting a single year of data is used for unit-level allowance allocation, EPA notes that both at proposal and final the EPA is using a 5-year baseline in its unit-level allowance allocation methodology. Therefore, contrary to suggestion by commenter, they are not penalized for one year of non-operation. See Preamble Section VI.B.9 for discussion of the allocation methodology.

In regard to allocations to Northeast Generating Station units 13 and 14, EPA notes that the allowance allocation at both proposal and final relies on a multi-year baseline, and a unit is not denied an allowance allocation simply because it did not operate in 2021 (commenter may have confused proposed state budget single year baseline with the allowance allocation methodology). Both units are included in the unit-level allowance allocations file and have the allocation methodology applied to them. In this case, the units receive little or no allowances not because of a single year baseline, but rather because they had little operation over a five year baseline as a share of the state's heat input. Even from a NOx standpoint, emissions for unit 13 ranged from 0 tons to 6 tons during the five-year baseline, and emissions from unit 14 ranged from 0 tons to 13 tons during the five-year baseline.

In regard to the comment that surplus allowances may not be available for trade due to prohibitions contained in other instruments such as NSR enforcement CDs, the Agency has not found any such restrictions to have been unduly harmful to liquidity in the prior trading program markets. In addition, the Agency has analyzed the quantities of allowances that would be allocated to units subject to consent decrees under the EPA's default unit-level allocation methodology in order to estimate how many allowances could potentially become subject to trading restrictions. The analysis indicates that the total quantities of allowances potentially subject to trading restrictions would be minimal if the default allocation methodology is used. For discussion of the EPA's analysis, see the Allowance Allocation Final Rule TSD. Moreover, any states concerned about the possibility that a small quantity of allowances in their state emissions budgets could become subject to trading restrictions under consent decrees could reduce that possibility starting with the 2024 control period by replacing the EPA's default unit-level allocation methodology with state-determined allocation methodologies that allocate smaller portions of their state emissions budgets to units subject to consent decrees. For discussion of states' options to establish state-determined allocation methodologies through SIP revisions, see Preamble Sections VI.D.1 through VI.D.3.

Relying on One Ozone Season Will Generate Inconsistent Results

Comments:

Commenter (0409) states that a single ozone season is a small snapshot from which to dictate future unit behavior. The commenter notes that generation asset use can vary greatly from year to year based on many outside factors that impact heat input, such as weather, forced outages, and fuel prices, all of which are unpredictable. The commenter adds that an ozone season in which gas prices are low may curtail coal unit dispatch; however, these units may need to be dispatched in the following ozone season if market circumstances change. According to the commenter, ratcheting down budgets based on one year's heat input would handcuff these units the following year. Coal-fired units would not have the flexibility to respond to the demand without sufficient NOx allocations.

The commenter (0409) suggests that using one ozone season to shrink state budgets is inconsistent with prior CSAPR methodology. The commenter explains that, previously, the EPA addressed unit retirements by removing those allocations from source accounts after five years and by periodically recalculating budgets when a new trading rule generation took root. For example, the Revised CSAPR Update Rule from 2021 did not put a regular budget recalibration in place. Instead, that rule relied on programmatic elements to adjust budgets such as retirement requirements and new unit set-asides for added generation. In this way, the commenter states that the revised CSAPR Update Rule incorporated a strategy to adjust state budgets commensurate with the changing EGU fleet.

Commenter (0409) notes that the CSAPR framework already contains components to address federally enforceable changes to state inventories (e.g., retirements, repowering) via new unit set-asides and removal of allocations for retirements. The commenter suggests that these concepts address EPA's concerns regarding changes in the fleet. Program stringency will be maintained without dynamic budgeting.

The commenter (0409) states that the emissions reductions from dynamic budgeting are not necessary to attain or maintain NAAQS in downwind states. Based on the commenter's analysis in the brief comment period, they do not believe that EPA's model included NOx reductions from dynamic budgeting. Therefore, they suggest that dynamic budgeting is not a concept that is required to achieve EPA's projected attainment at downwind receptors and produces an overcontrol scenario.

Commenter (0409) advocates for removal of dynamic budgeting. In the alternative, the commenter suggests that, at the very least, dynamic budgeting be based on an average of at least three ozone seasons. They also suggest that it not be an annual concept. With respect to retiring units, the commenter requests that the EPA retain the current CSAPR retired allocation approach of five years (2 consecutive control periods of nonoperation plus three years). In addition, they recommend that "retired" units be based on annual heat input rather than performance during the ozone season. Commenter (0394) states that EPA's assumptions regarding generation shifting are unrealistic, as IPM assumes there are no barriers to the movement of power within a state or within a regional transmission organization (RTO), disregarding the fact that the design and operation of the power delivery grid frequently dictates movement of energy, making the modeled generation shifts impossible. The commenter notes that generation shifting has a substantial effect on some state NOx emission budgets, resulting in budget reductions in the range of 700 to 1,100 tons of NOx – reductions of 1,138 tons of NOx for Kentucky; 971 tons of NOx for Missouri; 717 tons of NOx for Ohio; 1,034 tons of NOx for Texas; and 1,123 tons of NOx for West Virginia. The commenter notes that EPA's estimate of the low cost to deploy this approach result in an increased generation of select fossil fuel fired units and intermittent idling of select units across entire states and RTOs. The commenter contends that these conditions are unrealistic and should be eliminated from EPA's modeling for the proposed rule.

Commenter (0395) states that the EPA has proposed a "dynamic budget" as another new element to the existing CSAPR program structure and outside of EPA's authority. The commenter explains that it is not within EPA's authority to continue reducing the budget beyond what it has specifically supported by evidence in this rulemaking. Currently under CSAPR, the state budget, as well as any future state budgets, were laid out in a rule proposal to allow for appropriate notice and comment. Once adopted, those state budgets must remain static until a revision to the program is made using the rulemaking process and presenting the justification for the change. With the dynamic budget, the commenter states that the EPA is proposing to do away with notice and comment rulemakings for budget adjustments and thereby avoid having to present justification for future state budget decreases. The commenter contends that this dynamic budget presents a problem for many reasons: (1) state budget will spiral downward over time; (2) inflexible for changes in demand; (3) no justification for decrease in state budget; and (4) does not meet requirements for rulemaking.

Commenter (0395) states beginning in 2025, under this Proposal, a state's budget will begin to contract each year due to shutdowns, idling, generation and market demand. The tightening budget will cause significant problems for states that encounter changes in weather from year to year. The commenter also mentions the lack of justification for reduction and not meeting rulemaking requirements.

The commenter (0395) also states that tightening budget will cause significant problems for states that encounter changes in weather from year to year. A mild summer will cause the state budget two years into the future to shrink because allowances are based on heat input, rather than NOx emissions. However, if the state has a hot summer that year, the budget will be insufficient, and generators will be faced with a scenario of being called to provide power to the grid but not having the allowances to do so. While this can be possible even with a static budget, the dynamic nature and the downward spiral greatly exacerbate the problem, as do the other program "enhancements."

Commenters (0396, 0550) state the dynamic budgeting process functions to reduce a state's budget if the heat input utilized by its units drops below levels achieved in previous years, creating a perverse incentive for units to increase heat input to maintain budgets, particularly since unit allocations are also based on heat input. It also complicates planning efforts, since the regulated community will not be able to determine the state's budget, and therefore each unit's allocation of allowances from that budget, until about a year and a half before each control period. Dynamic budgeting also has another negative impact on the proposed trading program—it in effect eliminates from the state's budget the allowances previously allocated to retired units just two years after the units cease operations.

Commenter (0550) states that, as the Supreme Court previously explained, in CSAPR, EPA determined that "an upwind State 'contribute[d] significantly' to downwind nonattainment to the extent its exported pollution both (1) produced one percent or more of a NAAQS in at least one downwind State (step one) and (2) could be eliminated cost-effectively, as determined by EPA (step two)." And ultimately, "each upwind State will be required to reduce emissions by the amount necessary to eliminate that State's largest downwind contribution." The commenter notes that this is the approach that the Supreme Court deemed appropriate, but EPA cannot rely on this precedent to support its wholly new approach here wherein EPA would continually redefine the "amount," *i.e.,* the tons of emission reduction, that constitutes each state's significant contribution to downwind nonattainment or maintenance receptors through its dynamic budgeting process.

In justifying its dynamic budgeting approach, the commenter (0550) states that the EPA explains that while under "static budgets," "the initial mass-based budgets [*i.e.*, the budgets reflecting a state's significant contribution,] are achieved and compliance targets are even exceeded, this leads to a loss in efficacy of the program as the incentive to reduce emissions declines over time." But the commenter contends that the EPA ignores that the reductions it defined to be "significant" would have been achieved. The commenter asserts that the EPA cannot punish the electric generation industry simply because it has historically over-complied with EPA's mandates. According to the commenter, this past over-compliance does not give EPA free rein to redefine each state's significant contribution without limit. The commenter notes that the CAA and the Supreme Court have established an important backstop on EPA's authority to do so under Section 110.

Specifically, the commenter (0550) notes that, as the Supreme Court has affirmed, "[i]f EPA requires an upwind State to reduce emissions by more than the amount necessary to achieve attainment" in downwind states, "the Agency will have overstepped its authority, under the Good Neighbor Provision, to eliminate those 'amounts [that] contribute . . . to nonattainment.'" As a result, the commenter asserts that the EPA must determine the amount of a state's significant contribution by looking to the cost-effective reductions available from a state. If "initial mass-based budgets are achieved and compliance targets are even exceeded," as EPA has explained has happened under prior iterations of CSAPR, then the commenter notes that is the end of the analysis, and no further reductions are necessary. In other words, the commenter adds that once it has performed its analysis to determine a state's amount of significant contribution, EPA cannot continuously mandate additional reductions from states or particular sources beyond the amount it has found to be cost-effective at EPA's identified cost threshold, which is reflective of EPA's selected "control strategy." But the commenter notes that the EPA proposes to do just that here. According to the commenter, the obvious effect of EPA's proposed dynamic budgeting approach will be a ratcheting down of allowances for states as a whole, and coal-fired EGUs in particular, without regard for whether the emission budgets reflect the available cost- effective reductions for a given source or not, and beyond their point of "significant contribution."

Commenter (0505) provides that, in an effort to support its approach, EPA claims that "th[e] retention of a constant degree of stringency over time in emissions budgets under a flexible trading program would not constitute over- control any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute over-control." But, according to the commenter, the EPA misses the mark—the permanent imposition of emission rate standards on individual sources would constitute overcontrol at the point that those reductions are no longer needed to ensure downwind attainment. And, regardless, EPA has not assessed whether permanent, source-by-source emission rate limits will eliminate "significant contribution" but no more. Under either approach, if a state has eliminated its "significant contribution," no further reduction or obligation is permissible. The commenter contends that mandating the operation of controls in a certain manner regardless of a state's contribution constitutes unlawful overcontrol and should not be finalized.

Although the commenter (0505) believes that the EPA's proposed "dynamic budgeting" approach is technically flawed and unlawful on its face, if EPA does finalize such an approach, the EPA's proposal to treat its new budgets each year as a ministerial action is insufficient. The commenter explains that the EPA's "dynamic budgeting" approach, as proposed, does not include any backstop to prevent overcontrol. Through the dynamic budgeting process, EPA would essentially be proposing a new transport rule every year without confirming that future budgets will not require more reductions than are necessary to bring downwind receptors into attainment. The commenter recommends that the EPA perform a full analysis and provide for notice and comment of its new rulemaking each time it implements this process. According to the commenter, without a fulsome analysis and opportunity for comment, EPA will have violated the APA and failed to confirm the resulting budgets would not result in unlawful overcontrol.

Commenter (0505) states that EPA's ratcheting of the budgets in future years results in significant part from the retirement of units and does not give appropriate credit to such reductions from those retirements. The commenter explains that, in the Proposed FIP, EPA makes clear that when establishing states' budgets, EPA adjusts those budgets for any announced and confirmed retirement of an EGU. However, the commenter states that EPA also now plans to adjust budgets indefinitely into the future to account for future retirements of units. The commenter adds that the EPA claims that by using this approach, "the budgets will more accurately reflect power sector composition in that future year and will therefore better achieve the desired environmental outcome over time." However, the commenter asserts that, ultimately, this approach just punishes states with sources that choose to comply with EPA's Proposed FIP through retirement and disincentivizes companies from retiring their least effectively controlled units.

Commenter (0505) provides that the EPA explains that its "dynamic budgeting process," which considers retirements when setting future budgets, "would protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and would better sustain over time the incentives created by the trading program to apply continuously the degree of emissions control the EPA determines is necessary to address states' good neighbor obligations." However, the commenter does not believe that this approach "incentivizes" EGUs to implement EPA's selected control technology; it incentivizes companies to continue to run their sources with the largest allocations for as long as possible and avoid the potential early retirement of units. Accordingly, the commenter recommends that the allowances from retired units continue to be allocated and able to be "used and/or banked" for a period of no shorter than five years after the retirement date. The commenter contends that this will continue to incentivize retirements and allow unit retirement to be a viable compliance strategy.

Commenter (0394) claims that EPA's proposal to require dynamic state emissions budgets for future control periods beginning with the ozone season in 2025 will result in reduced budgets, prohibiting previously budgeted emissions, which reflect emissions remaining after application of cost-effective emission reductions. By reducing state budgets and imposing program-level and unit-specific "enhancements," the commenter states that the proposal mandates "command and control" reductions in addition to those the affected units have achieved to comply with the "market based" budget program. In other words, they require reductions below budgeted emissions that are not prohibited under the Good Neighbor provision. These budgeted emissions are the emissions that remain after elimination of those emissions that can be eliminated through cost effective emission reductions. As the Supreme Court has emphasized, the commenter states that the EPA may only require states to reduce emissions that contribute "one percent or more of a NAAQS in [a] downwind state," and can "be eliminated cost effectively." According to the commenter, the EPA lacks authority under the Good Neighbor Provision to demand reductions to improve an individual unit's emissions performance when market driven reductions at other units, or a unit's current emission performance, assures compliance with a state's budget. The commenter states that the EPA may only control upwind-state sources to eliminate the amount of emissions that contribute significantly to nonattainment in, or interfere with maintenance by, downwind states, quantified in each state's emission budget.

Commenter (0400) contends that dynamic state emission budgets are unauthorized under the good neighbor provision because the failure to eliminate significant contribution to nonattainment has been mitigated through compliance with state budgets. The commenter goes on to contend that assuming that the EPA had legal authority to dynamically budget, it procedurally may do so only through additional Section 307(d) FIP rulemaking.

Commenters (0408, 0414, 0533) state the proposed dynamic budgeting process arbitrarily ties a state's budget to a single operating year that may not be characteristic of normal EGU operations. It could force coal-fired units to operate at a reduced capacity due to a lack of sufficient allowances. Because the budget and the allowance bank will be revised yearly, the commenter will not be able to make necessary adjustments to comply with future allocations. The dramatic price fluctuations of the current Group 3 allowances are an indicator of the potential price volatility that would increase uncertainty in resource planning. Commenter (0408) suggests dynamic budgeting utilize the average highest three in five years heat input value, technology specific emissions rate for SCR (0.08 lb/mmbtu for existing and reasonably achievable control technology, ~0.07 lb/mmbtu, for SOA SCR), and average highest three in five years actual emissions rates for pre-existing non-SCR combustion controls.

Commenter (0414) claims that dynamic budget methodology that relies on a single past year's operations (heat input) does not provide adequate flexibility to handle changes in operation two control periods later due to unplanned events (e.g., prolonged periods of no wind generation during peak demand periods, reductions in electricity from hydropower due to droughts, and lengthy nuclear outages). At a minimum, the commenter believes that EPA should adopt a dynamic budget methodology that relies on the previous five-year period for heat input values as used in the methodology for existing unit-level allocations and would also allow a more contemporaneous reflection of units that cease operation or retire than the existing methodology.

Commenter (0533) states that the proposed FIP's dynamic budget approach would significantly restrict state budgets and, correspondingly, unit-level allocations beginning in 2025, with the problem becoming worse beginning in 2026. For coal-, oil-, and gas-fired EGUs currently without an SCR, the proposed dynamic budget approach is untenable. In light of potential delays in the installation of SCRs, significant installation costs, and anticipated post-2026 retirements, the commenter notes that the state budgets that EPA is proposing, even without consideration of the dynamic budget-setting process, are likely to restrict operations at some EGUs during the ozone season. As noted above, the commenter contends that Group 3 allowances under the current program are already scarce and those that are available are selling at a much higher price than allowances under the other CSAPR programs. According to the commenter, this alone is concerning, but it is compounded by the dynamic nature of the budgets and the allowance bank recalibration. The commenter states that, if EGUs must operate at a reduced capacity due to a lack of sufficient allowances, the state budget in two years will reflect that decrease and the state budget will shrink, as will the units' corresponding allowance allocations. Eventually, the commenter reports that such units will have little to no allowances and will be unable to effectively operate.

Additionally, commenter (0533) provides that the dynamic budget has the potential to result in overcontrol. Because of the dynamic nature of the proposed state budgets, they may shrink significantly as a result of reduced capacity or retirements, and EPA has not proposed an end to the recurring annual recalculation of the budgets. According to the commenter, the Proposed FIP does not have a mechanism to reassess whether the future budgets would be reduced to a point where the state is no longer contributing one percent of the NAAQS to downwind areas or if the downwind monitors reach attainment. The commenter asserts that the EPA cannot use a static set of modeling results to inform a program that extends into the future and where state budgets are constantly being adjusted based on factors not directly tied to air quality monitoring or modeling. If EPA finalizes the dynamic budget approach, the commenter recommends that the EPA reevaluate its four-step analysis, including the modeling, for each recalculation of the state budgets, to ensure that states are not being overcontrolled.

Commenter (0533) notes that, if EPA proceeds with a dynamic budget, the Group strongly urges EPA to utilize a multiyear approach both in establishing the timing and the level of the future year state budgets. First, the commenter provides that the EPA proposes to revise the budgets annually, beginning with the 2026 ozone season. Instead, the commenter recommends that EPA only revise the level of the state budgets over a multi-year period, such as three years, to provide some certainty in the market and allow companies to plan for future operations. Second, EPA proposes to base future year budgets from heat input data in the state for a single year. The commenter contends that such an approach could result in budgets based on anomalous years due to unexpected outages with no clear method for correction. For example, in high hurricane activity years, the commenter notes that it is possible for several units in a state to be offline for all or parts of the ozone season. Under the dynamic budget approach, two years after that hurricane, a state's budget would be reduced to reflect an extraordinary and inappropriate reduction in emissions from those units that were forced offline. NOx emissions during the ozone season were uncharacteristically low during 2020 due to the pandemic. The commenter notes that it is very possible that another pandemic could result in another anomalous ozone season in the near future. The commenter also notes that other circumstances also could result in anomalous years, such as fuel price fluctuations or a cooler than average summer that idles more units than expected. The commenter explains that such circumstances could result in a lower state budget in the second year following such circumstances. The commenter adds that any offline units would effectively be removed from the state budget. As a result, the commenter states that one unit being offline for a single ozone season reduces the entire state budget and, correspondingly, all unit allocations. Further, the commenter adds that the unit that experienced an outage or was idled may not be able to maintain normal operations once the state's budget has been reduced to exclude it because the unit may not have enough allowances to cover normal operations. According to the commenter, the one-year approach to the dynamic budget harms the ability of electric generating companies to continue to operate cost-effectively and provide reliable generation in future years. The commenter states that, if EPA still believes a dynamic budget is necessary, they urge EPA to set future year state budgets based on an average of multi-year data, for example the highest three of the last five years, rather than using a single-year approach. The commenter notes that this would allow the budgets to reflect typical conditions rather than imposing a budget on the state based on atypical operations in a single year. According to the commenter, this also would be consistent with EPA's approach to unit-level allocations, which are based on multi-year data, and which the Class of '85 supports. The commenter recommends that the EPA also not annually revise the state budgets but should only do so on a periodic basis, such as every three years.

Commenter (0409) also states dynamic budgeting presents significant potential allowance short falls if EPA's future projections of baseload and intermediate generation fall short and this imposes risks on grid reliability.

Commenter (0411) states the process by which a state's annual allowance allocation is determined penalizes states for years in which units are brought offline during the ozone season for extended periods of time regardless of the reason(s). The commenter suggests the state allowance budgets to be based on a 3-year lookback period in lieu of a single year. The commenter also notes dynamic budgeting proposal also will result in a tight allowance market where allowance holders will be reluctant to sell their small number of excess allowances, if there are any excess allowances at all. Additionally, the commenter states it unintentionally incentivizes maximizing the operation of a unit during an ozone season to preserve budget allocations, it also penalizes those units that are offline for all, or a significant portion of, the ozone season even if those units are offline due to circumstances beyond their control (e.g., wildfires, extreme weather, unplanned equipment failure, etc.).

Commenter (0412) states dynamic budgeting introduces reliability risks caused by the late availability of data that is critical to resource adequacy planning both near-term and in future years, and it renders grid reliability concerns.

Commenter (0424) states dynamic state emissions budgets for EGUs exceeds EPA's authority under the good neighbor provision and, even if EPA had authority to change state budgets from year to year, it could not do so without notice-and-comment rulemaking. Commenter (0424) clarifies that if EPA had substantive authority to change the stringency of state budgets, they could only do so following a Section 307(d) FIP rulemaking. Meaning, EPA could not do so without affording notice to the public and an opportunity for comment.

Commenters (0499, 0547) state dynamic budget approach would significantly restrict state budgets and, correspondingly, unit-level allocations beginning in 2025 and may result in overcontrol. The dynamic budget and annual allowance bank recalibration create unnecessary regulatory uncertainty for EGUs.

Commenters (0500, 0530, 0553, 0782) state once a state budget is set for a full remedy, additional reductions are overcontrol; automatic changes to dynamic budgets via “ministerial action” will not allow for public review and comment; dynamic budgeting should focus on multi-year averages to avoid penalizing a state for a low-emitting year; with a fleet in transition, historical years may not be a good indicator of future needs. Commenter (0500) asserts that creating a new annual budget as conceived by EPA is not a ministerial action, but rather constitutes an agency action subject to notice and comment rulemaking; therefore, EPA should agree to adjusting the budgets, as necessary, via full notice and comment rulemaking. Furthermore, because the proposal envisions this process [dynamic budgeting adjustments] going forward in perpetuity, it will almost certainly result in inappropriate budget adjustments due to years with unusually low heat input caused by infrequent, atypical conditions, which will inevitably occur. Commenter (0500) suggests that EPA amend the proposed approach for recurring annual dynamic budgeting to include a multi-year historical average heat input similar to what EPA proposes to use to set the allocations for individual units, which are based on a heat input average from the three highest years in the preceding five years – to mitigate the effect of atypical years.

Commenter (0506) states EPA should finalize its proposal to set “dynamic” state budgets based on the latest information available on the composition and utilization of the electric generating fleet beginning with the 2025 control period. Commenter (0506) asks that the calculation of dynamic budgets in the final rule should clarify that to identify retired units, EPA will consider the same data sources used to identify planned retirements in the NEEDS database. In addition, to ensure that the latest information on expected changes to the generation stack is reflected in the dynamic budget, commenter encourages EPA to consider company Integrated Resource Plans, SEC filings, company press releases, and the latest DOE EIA Form 860 monthly reports.

Commenter (0515) states the process creates a real possibility that operations of gas-fired units may become so constrained in future years that grid operators are unable to reliably operate the system and suggests that a more permanent approach to allocations would reduce volatility, increase liquidity, and provide a more stable long-term planning platform. To illustrate, commenter explains that in a high (wet) hydro generation year with mild conditions, some gas-fired peakers may not run very much, if at all. However, if the next year is dry and hot, there may not be enough allowances available to gas-fired generation to run enough to meet the grid operators’ increased needs.

Commenter (0528) states the new budget process will use the most recent ozone season data to establish future year budgets. For units that do not operate for an ozone season, for example, the dynamic budget means that the unit will be removed from the calculation of the state’s budget two ozone seasons after it failed to operate. As a result, the entire state budget, and correspondingly, unit-level allowance allocations to all EGUs in the state, would shrink.

Commenter (0530) suggests consideration of facility-specific supplemental information and multi-year averaging to set dynamic budgets.

Commenter (0542) states it is illegal for EPA to intend to utilize “ministerial actions” in place of the required rulemaking process for the finalizing the annual dynamic emissions budgets proposed in the Transport Rule FIP. The commenter maintains that moving away from fixed allocations decreases the certainty of future allowances and causes the market price for allowances to stay high even if more sources shutdown than expected. Because EPA is basing Step 3 allocations on the emissions that can be cost effectively removed, the dynamic allocation approach serves to calibrate the tons of allowances to actual operation at the target emissions rate with controls, and as a result, it is not clear to the commenter what allocations RHGF would actually receive in 2025 and beyond, as those would not be determined until May 1, 2024, based on data from 2023. Commenter worries that budgeting and planning for power plant owners will become increasingly difficult given the uncertainty of future allocations. Furthermore, EPA admits its analysis of the trading program "does not explicitly capture the dynamic budget over time,” and therefore flawed. The commenter also states dynamic budgets have never before been included in EPA’s good neighbor provisions and in the resulting allowance-based trading programs, likely due to the pricing disruption they will cause in the credit marketplace. Finally, the commenter notes the 2026 beginning time is challenging; noting EPA disregards modern-day realties such as labor shortages and supply chain disruptions that may be exacerbated in unpredictable ways due to the COVID-19 pandemic and record-breaking inflation in the United States.

Commenters (0550, 0541) state that the EPA’s dynamic budget approach results in unlawful overcontrol because the EPA misses the mark—the permanent imposition of emission rate standards on individual sources would constitute overcontrol at the point that those reductions are no longer needed to ensure downwind attainment. Commenter (0541) maintains that the EPA cannot continually re-define what constitutes the “amount” of a state’s significant contribution through its dynamic budgeting process.

Commenter (0551) states that the dynamic budgeting process cannot be justified, and if it is to be retained, the commenter suggests developing a safety valve provision that could effectively address the over-control problem raised by dynamic budgeting. To illustrate, the commenter recalls that the proposed dynamic budgeting provisions would recalculate each state’s annual NOx budget to reflect changes in fleet composition and heat input starting in 2025 and continuing thereafter; noting the goal is to prevent “industry trends toward more efficient and cleaner resources ... likely lead[ing] to a surplus of allowances” in future years. The commenter concludes that the EPA’s own description demonstrates that the dynamic budgets are not intended to address significant contribution, but rather they are intended to ensure controls are operated and that emission rate limits are achieved even if states have eliminated their significant contributions. The commenter asserts that the fact that the EPA says these emission reductions are needed to address good neighbor obligations, but that EPA cannot at this time state what these emission reductions will be, demonstrates just how problematic—and inconsistent with section 110(a)(2)(D)(i)(I)—the dynamic budgeting provision is.

Commenter (0551) states that the disconnect between the dynamic budgeting provision and significant contribution is made most explicit by its effect on states that are projected to resolve their good neighbor obligations by 2023. The commenter notes that the EPA's air modeling shows that all receptors to which Alabama, Delaware, and Tennessee are linked in 2023 are projected to be in attainment by 2026. The EPA projects that these states will be well below the proposed one percent contribution threshold. Therefore, "no additional emissions reductions are proposed for EGUs or non-EGUs in those states beyond the 2023 level of stringency," nor can they be under the Supreme Court's holding in *EME Homer II*. Despite this finding, the commenter states that the dynamic budgeting provision will continue to apply, requiring reductions beyond 2023 levels. The other enhancements will also apply and, if they work as EPA projects, will ensure controls operate and unnecessary emission reductions continue. For the reasons the Supreme Court identified, this is over-control.

The commenter (0551) contends that the dynamic budgeting provisions could allow a state to emit at levels in excess of the budgets that would otherwise be established for 2026. As with CAIR, they note that it would allow under-control that would also fail to address significant contribution in an appropriate manner. Although far less likely, the commenter suggests that this is just as serious a flaw with the Proposed Rule's design. Accordingly, consistent with the D.C. Circuit's decision in North Carolina which prohibited such under-control, the commenter recommends that the EPA eliminate the dynamic budgeting provision from its final rule.

According to the commenter (0551), if EPA decides to retain the dynamic budgeting provisions, it may be possible to develop a safety valve provision that could effectively address the over-control problem raised by unmitigated dynamic budgeting. The commenter explains that such a safety valve would need to be tied to a defined level of significant contribution such that EPA would cease realigning budgets or take other similarly protective action once that level was reached. The commenter welcomes the opportunity to further work with EPA to develop any such safety valve.

Commenter (0553) states the process for defining control technology stringency under a command-and-control program and the stringency assigned to EGUs under a regional NOx budget trading program are quite different. The EPA's methodology which would adjust the NOx budgets based on the levels of operation each unit experienced in the ozone season two years prior has the effect of increasing the control stringency over time, resulting in greater control cost than EPA assumed in establishing the requirements in the Proposed FIP. To illustrate, the commenter notes if an EGU that emits NOx at a rate of 0.07 lb/MMBtu incurs a significant outage taking the unit out of service for much of the ozone season and the generation is met in part by increased generation from sources in another state within the same Regional Transmission Organization (RTO), then the state budget will be reduced for the ozone season two years later. For compliance planning, the commenter asserts that EGU owners would respond to the reduced budget by taking further steps to reduce emissions to minimize any shortfall of allowances, and these reductions would go beyond a need to address downwind ozone or to meet a specified control technology standard. The commenter contends that the EPA's proposed budget setting process has no bounds in degree or time and allows EPA the authority to set yearly ozone season NOx budgets for a state without regard to whether the budget is necessary to eliminate downwind ozone concerns. Having budgets determined year-to-year based on levels of operation just two years prior creates a high level of uncertainty in the allowance market.

Commenter (0554) states the use of dynamic budgeting to determine state emissions budgets and set a targeted allowance bank size starting in 2025 will overly constrain units. It also deprives the public of a reasonable opportunity to meaningfully comment on EPA's future state- and unit-level NOx budgets, in contravention of APA's rulemaking requirements.

Commenter (0547) states time period between budget setting and control period is too short. The EPA is proposing to calculate emissions budgets by March 1 of the year preceding the control period, with final budgets due by May 1 of the year before the control period to which those budgets apply. The commenter is concerned that there will not be enough allowances to operate its units through that ozone season and recommends that EPA finalize budgets at least two years prior to the control period. The commenter also states budgeting methodology is inequitable and fails to consider important factors that impact heat input and emissions. The commenter recommends considering other representative factors when calculating dynamic budgets. Finally, the commenter notes the rule does not provide a dedicated process or off-ramp to address the likely scenario that a lack of allowances affects grid stability and reliability. If the commenter is unable to obtain allowances to cover its emissions at a reasonable price, it may be forced to shut down its units. To illustrate, the commenter worries that it could be short of allowances for as much as six weeks of energy generation for the 2023 control period based upon the proposed initial allocations, and if they are unable to obtain allowances to cover its emissions at a reasonable price, it may be forced to shut down its units – a significant reduction in generation capacity could have far reaching effects on grid reliability

Commenter (0758) supports EPA's proposal to include a mechanism for adjusting state budgets to reflect the most recent data on the state's fleet composition and heat input to their fossil-fuel-fired EGUs. The commenter states that, omitting the EPA's proposed dynamic-budgeting feature would not only result in a rule that fails to eliminate significant contributions from EGUs going forward, but it would also be arbitrary—as unfounded as a hypothetical rule that lifts unit-specific emissions rate limits from sources in an industrial sector when that sector shrinks, even though the state remains linked to a downwind nonattainment or maintenance issue above the significance threshold.

In general, commenter (0758) endorses the mechanism that EPA has proposed to implement dynamic budgeting for the states' fossil-fuel-fired fleets. According to the commenter, although it would be preferable to implement an even more responsive dynamic-budgeting mechanism that takes into account unplanned additions and retirements of EGUs in the year leading up to the relevant control period, this accelerated timing could disrupt the smooth functioning of the trading program by injecting uncertainty as to the number of allowances available in the upcoming control period (and therefore the assurance level that the state's fleet must stay below, while providing reliable power supply). Therefore, the commenter supports a dynamic-budgeting mechanism that relies on heat-input data from the control period two years before the period to which the budget will apply. See 87 Fed. Reg. at 20,108.

On the other hand, the commenter (0758) recommends that the EPA account for all retirements (and additions) that are planned to occur before or within the control period for which it is computing a budget, instead of relying solely on the heat-input data of the fleet as it existed two control periods prior. For example, when calculating the budget for 2025, the commenter suggests that the EPA apply the selected control strategy to the fleet as it operated in 2023 but remove units that will retire before or during the 2025 control period. According to the commenter, this approach would lead to a more accurate representation of the fleet in the future year in question while preserving certainty as to the number of allowances in the budget for that year.

Commenter (0758) notes that the EPA need not initiate a new rulemaking each time it implements its proposed dynamic-budgeting mechanism and updates states' budgets. Thus, EPA's determination of the control strategy that eliminates significant contributions would not change with future budget computations, and there is no need to reopen for notice and comment the continued implementation of this policy. Accordingly, the commenter recommends that EPA carry out the dynamic-budgeting computations through a ministerial process—as with other routine implementation tasks, such as annually allocating allowances to the units that remain in or have recently entered the program. See id. at 20,115.

Finally, commenter (0758) states that, regardless of the precise approach that EPA ultimately selects for implementing the dynamic budgets, they recommend that the agency finalize the "illustrative state emissions budgets" for the 2025 and 2026 control periods, 87 Fed. Reg. at 20,117-18, as default budgets that would take effect in the event that EPA, for any reason, did not complete the ministerial dynamic-budget process for those years on the anticipated schedule. The commenter states that the EPA has confirmed that these illustrative budgets, reflecting the selected control strategy for 2025 and 2026 as applied to the most recent historical heat-input data, likely does not result in overcontrol for any state covered by the EGU program, with the possible exceptions of Arkansas, Mississippi and Wyoming—all of which can and should be addressed in the final rule based on these comments. See id. at 20,098-99. According to the commenter, establishing these presumptive or default budgets now would provide sources in the EGU trading program—as well as beneficiaries of the Good Neighbor Rule— greater regulatory certainty by setting binding overall limits on EGUs' emissions in 2025 and 2026 that would take effect notwithstanding any delays or difficulties that EPA may encounter in carrying out the ministerial dynamic-budgeting process for these years.

Commenter (0366) claims that the dynamic budget methodology simply creates too much uncertainty and the one-year prior notice given to respond to computed/published budgets does not allow sufficient time for industry to properly plan for compliance; noting that industry often work on five-year planning cycles. The commenter acknowledges that an affected unit's status could change from one year to the next altering that unit's allowance allocation and corresponding need for emissions controls or to secure allowances.

The commenter (0302) requests that the state budgets be calculated with a longer period of operational data as opposed to relying on one single year of operations. Specifically, the commenter requests that, if EPA will not eliminate the dynamic budgeting process, state budgets be calculated with a longer period of operational data as opposed to relying on one single year of operations. According to the commenter, the use of one year of data to establish the state budget is not representative of the operational history of the affected units. The commenter suggests that using just a single year of operations would deny the state and each affected unit of the appropriate allowance allocations. (Note: The commenter notes that their companies (Evergy's) Northeast Station Units 13 and 14 are examples of affected units being denied initial allowance allocation. This is discussed at the end of the commenter's letter.) In this situation the state-wide budget would be decreased for the following year with no mechanism in place for it to ever increase back to a value representative of how the units typically operate when not in a large planned or unplanned outage. According to the commenter, this would create a perpetual reduction in the overall state budgets as various units across the state take planned outages or have equipment failures over time. The commenter recommends the use of the three highest years out of the previous five years to be much more representative of how the units collectively operate in the state.

Commenter (0330) provides several options that could potentially alleviate some of the concerns they have with allowance allocations including using a multiple-year (*e.g.*, 3 highest years of the most recent 5 years of historical operation) average in place of the proposed one-year operational look-back to assure that EGUs are not penalized for decreased operation in any given year. The commenter explains that decreased operation may occur as units periodically have extended maintenance outages or for unforeseen circumstances such as the 2020 COVID pandemic. The commenter believes that the proposed one-year look-back would penalize future year operations of the EGU because of limited allowance allocations in those circumstances.

Commenter (0414) recommends using the average of the most recent five years of heat input values instead of the most recent single year when determining dynamic state emission budgets for control periods starting in 2025. The commenter states that this change, along with others EPA would use to determine allocations to existing units, would still allow EPA to reflect more quickly unit retirements than in the current system.

Commenter (0541) proposes that the EPA recalibrate state budgets based on the highest of three previous years instead of a single year (similar to the proposed unit allocation procedure) to limit the effects of natural variability on state budgets.

The commenter (0544) proposes the following alternative regulatory approaches to the dynamic adjustment provisions in the proposed rule:

Option 1. EPA should amend the proposed rule to utilize a three-year average of ozone season heat input data. Using a three-season average rather than a single ozone season to set a future year budget will be better representative of how the EGU fleet operates and will minimize the impact of fluctuations due to weather, maintenance, and other transitory issues on a future state NOx emissions budget. This option is also consistent with the approach the EPA has taken in prior CSAPR rulemakings to ensure that unit-level allocations are not inappropriately impacted by outages or other unusual events in a single ozone season.

Option 2. A mechanism should be included in the proposed rule to prorate the data used in the dynamic adjustment if a unit experienced a planned or unplanned outage in a given ozone season. The unit's average daily heat input for the ozone season should be imputed to each day in the outage period, so that the total heat input for the ozone season reflects the unit's potential operation but for the outage.

Alternatively, if a three-year average or a mechanism to account for planned or unplanned outages cannot be incorporated into the dynamic adjustment of state NOx emissions budgets, the commenter proposes that the dynamic adjustment proposal be removed from the proposed rule. In lieu of the dynamic adjustment, the commenter (0544) proposes that EPA reserve future state NOx emissions budget adjustments for notice-and-comment rulemaking that would be initiated upon a defined trigger, such as NOx allowance prices falling to a certain price point. In this way, if static state NOx emissions budgets do in fact result in the availability of excessive NOx allowances such that prices fall and operators are not incentivized to fully operate and optimize SCR controls, EPA may update the state NOx emissions budgets at that time based on actual EGU utilization data and taking into account planned and unplanned outages.

According to the commenter (0544), each proposal would capture actual changes in the composition of the EGU fleet and changes in EGU utilization over time and would maintain the CSAPR Program control stringency over time—the outcome EPA seeks—while avoiding an artificial reduction in the state NOx emissions budgets.

Commenter (0760) states the proposed rule indicates that in 2026 there will be a significant decrease in the Ozone Season NOx allowance allocations for all Louisiana EGUS, from 9,179 tons in 2023 to only 3,752 tons in 2026. The commenter challenges the technical basis for this 60% reduction. For example, the commenter notes that the illustrative allowances indicate that the allocations for one of LCA's members, Eagle US 2/RS Cogen will decrease abruptly in 2026 by over 50% even though the primary purpose of the units are to provide power to the company's chemical manufacturing operations, no changes in operation are planned, and the units are extremely efficient cogeneration units already equipped with UNLB and SCR. The commenter adds that the heat input rates and operations of these units have been consistent over the years. The Eagle/RS Cogen RS-5 and RS-6 cogeneration units operate at 32% below EPA's optimized NOx benchmark performance level of 0.081 lb NOx/MMBtu (or 22 ppmvd NOx @ 15% O2d). According to the commenter, the additional NOx controls are not justified based on the already good performance of these units. Thus, the only means to achieve the proposed 2026 allowances would be to curtail operations. The commenter states that any curtailment of operation of RS-5 or RS-6 would lead to curtailment of Eagle's manufacturing operations. The commenter asserts that the same can be said of other EGUs that provide a substantial source of power to chemical manufacturing facilities and only a portion to the grid.

Commenter (0760) urges EPA to reconsider its projections for EGUs. The commenter believes that the EPA's reasoning for the significant allocation reductions to EGUs that are cogeneration units primarily serving chemical plants must be explained as there does not appear to be any rational basis for projecting decreased electrical needs for the chemical manufacturing units served. Further, the commenter suggests that the EPA not impose any significant reductions to the unit-specific OS NOx allowance allocations for any already well-controlled units. The commenter notes that such reductions would have no technical basis.

Commenter (0412) recommends that EPA establish an "allowance reserve account" that would allow a utility to purchase additional allowances at a "fair market price" if a unit's actual heat input exceeds the historical heat input EPA used in determining the state budget for a specific budget year. The commenter notes that if EPA guesses correctly as the proposal contemplates the "allowance reserve" would never be needed assuming the above-described changes are made to the proposal.

Response:

See Section VI.B.1.d and VI.B.4.b of the preamble, where EPA describes the final rule's use of a multi-year baseline in dynamic budgets consistent with suggestions in many of the above comments.

Additionally, in regard to comments that suggest EPA should not immediately remove retiring units from state emissions budgets under a dynamic budget approach and that such an approach would disincentivize the retirement or make retirement less useful as an alternative compliance pathway, EPA notes that each dynamic budget will be calculated using heat input from multiple historical control periods, the most recent of which will be the control period two years before the control period for which the retirement is first taken into account in the budget-setting calculations. Any impact of a retirement on a state's dynamic budgets will therefore not start immediately and will be phased in over multiple control periods, substantially mitigating the concerns raised by commenters.

In regard to comments suggesting the dynamic budget should remove a recent or planned retirement unit altogether from the inventory in all baseline years of heat input informing the dynamic budget, EPA notes that while that approach would more quickly phase out the emissions of the retiring unit it would involve subsequent assumptions and evaluations regarding replacement generation, and the EPA did not propose a methodology for developing such assumptions for future control periods in a nondiscretionary manner. Absent such a nondiscretionary methodology, adjusting the historical data so as to exclude retired units could undermine one of the strengths of the dynamic budget-setting methodology, namely that it is entirely ministerial, with dynamic budgets determined solely based on emissions rate values finalized in the rule and rolling heat input values calculated from reported data in a well-defined, nondiscretionary manner.

In regards to use of a single year of 2021 heat input for preset budgets, EPA thinks this is most appropriate as it is the most recent and most aligned with the fleet composition going forward, consequently it is the most representative. The EPA examined the total fossil fuel heat input for the 22 covered states in 2021 relative to pre-pandemic trends and operating levels (and also compared to subsequently available 2022 data). The EPA determined that 2021, unlike 2020, is in line with pre-pandemic fossil heat input and trends. Total fossil fuel heat input for the 22 covered states for the EGU trading program in 2021 were within .1% of what they were in 2022 (unlike 2020 which was nearly 6% lower).

Improper Use of 2021 Data to Project Future 2023, 2026, and 2032 Baselines and Budgets –State Budget Allocations Based on 5 Years

Comments:

Commenter (0302) states when setting state budgets in the proposed rule, EPA utilized a single year consisting of the 2021 operating rate for units with SCRs. If the unit was operating above 0.08 lb/mmbtu then the emission rate of 0.08 lb/mmbtu was used to set the state budget. However, if a unit was operating below 0.08 lb/mmbtu then the lower emission rate was used. The commenter believes for existing units EPA should use the 0.08 lb/mmbtu value or the federally enforceable permit limit as the minimum value rather than the maximum. If EPA is insistent on relying on a single year of heat input, the commenter proposes a more equitable approach of calculating state budgets. Specifically, commenter (0302) requests EPA change the assumption for existing units with SCRs which have historically operated well below 0.08 lb/mmBtu to assume a 0.08 lb/mmBtu NOx emission rate similar to existing units with SCR which have historically operated above 0.08 lb/mmBtu. This change in emission calculation methodology would add an additional 497 NOx allowances to the Missouri state budget.

Commenters (0361, 0408, 0409, 0411, 0528, 0550) state emissions rates vary significantly from year-to-year. Consequently, an analysis accounting for multiple years would more accurately assess a baseline for the relevant EGU. The use of a single ozone season base case to “lock in” EGU runtime nationwide is erroneous. The model plugs in unit-level heat input data from 2021 for use in state budgets. The EPA presumes 2021 heat inputs are appropriate as a representative year of consumer demand. In so doing, the model caps heat inputs for all future years.

Commenter (0366) states the EPA has not explained the basis for its shift in its long-standing policy of using, five years of operational data to set state emissions budget allocations for trading programs. “An unexplained deviation from past practice can render an agency’s decision arbitrary and capricious.” In contrast, the EPA would base future year budgets on a single operational year. In context of the major New Source Review (NSR) program, EPA determined that five years of data are necessary to capture the normal business cycles of Electric Utility Steam Generating Unit (EUSGU) operations, and ten years of data is necessary for other industries. Commenter (0366) argues EPA’s proposed rule would depart from EPA’s long-standing precedent of using multiple years of data to establish representative baselines without explaining the departure or providing a rationale. The commenter states EPA’s preamble is unclear on how a single year of data would help EPA distinguish changes in the composition and utilization of the EGU fleet (EPA’s stated reason for the new budgeting approach) from changes in emissions caused by normal variability in dispatch and operations.

Commenter (0554) asserts the 2023-2024 state budgets are based on 2021 ozone season actual heat inputs, and 2025 budgets and beyond will be based on the heat input from the ozone season two years prior to the budgeted year. This methodology is flawed. If a facility has a scheduled or forced outage during the ozone season, the decrease in heat input due to the outage will limit the state budget two years later in a way not representative of future operations and emissions. For example, PacifiCorp’s Naughton Unit 1 had a scheduled maintenance outage that ended May 29, 2021, which significantly reduced the unit’s ozone season heat input used to determine Wyoming’s state allocations for 2023. That unrepresentative outcome would continue under EPA’s current methodology, penalizing companies for outages that occur during ozone season, even though the emission reductions and repairs that result from those outages further the purpose of the proposed rule.

Commenter (0554) believes that the use of a single year to establish the 2023 allocation is short-sighted and unfair. It does not correctly account for routine events that should not penalize a unit or a state's budget. A methodology where state budgets are based on an average of the three highest heat inputs from the past five years during the ozone season will better represent actual operations and smooth out variations that occur year-to-year due to both routine outages and unexpected upsets or other unavoidable operating conditions.

Response:

EPA addresses comments on the budget-setting approach in Preamble Section VI.B.4.a and discusses comments on the approach to setting unit-level allocations in Preamble Section VI.B.9 as well as section 5.2.17 of this RTC. The EPA notes, contrary to commenter's assertion, none of its prior CSAPR programs have used five-year historical data baselines to set state emissions budgets (such data has been used in the unit-level allocation determination process that occurs separately and independently from the process for setting state emissions budgets).

Failure to Account for Future Generation Demands

Comments:

Commenters (0372, 0409) believe there are no adjustments in state budgets to account for future generation demands. Commenter (0409) references a National Renewable Energy Laboratory (NREL) study projecting that future electricity demand will increase. Future power sector demands are modeled to grow by 20% and 35% under NREL's medium and high scenarios, respectively, reflecting impacts such as electrification of transportation and building sectors. Commenter (0409) goes further stating dynamic budgeting will not correct this problem. If units operate more, increased combustion results in additional NOx emissions. However, units cannot practically emit much above 2021 heat inputs due to scarcity of allocations, state budget size, and resulting assurance features in the Proposed FIP. Dynamic budgeting will only serve to decrease budgets, which will not account for increased demand. Commenter (0409) provides the example, if a unit runs at a capacity factor of 80% in 2021 (or 60%, as commenter (0372) provides), the model assumes its NOx tonnage (translating into its Group 3 allocations) based on that runtime number. However, if demand from the RTO is higher in a future year, that unit will not have allocations to cover the additional operation. The utility owner must curtail the units due to this Rule or determine whether it can afford to purchase allowances, which commenters (0372, 0409) project to be cost prohibitive. The only other option would be building new generation (*i.e.*, a growth factor) into the state budgets. The end result is unworkable and expensive if an existing unit cannot cover the increased demand.

Commenter (0758) disagrees with EPA's conclusion, however, that "[e]mission reductions derived from generation shifting will be captured in the dynamic budgets in all cases" and that generation shifting "will be directly incorporated through the inclusion of updated heat input data reflecting observed, post-compliance generation shifting." True, generation-shifting that has already occurred as a response to the NOx price in prior program years will be incorporated into future budgets through the dynamic-budgeting mechanism. Yet, under those reduced budgets, covered EGUs will still face a NOx price reflecting the cost of abatement at the selected level of control. Given increased availability of zero- or lower-emitting resources with lower variable costs, some covered EGUs may continue to find it more cost-effective to shift generation than to install and run the selected controls. As part of its dynamic budgeting process each year, EPA should model that generation shifting and remove allowances representing equivalent emission reductions from the budgets in the upcoming control period. Without accounting for generation shifting in the dynamic-budgeting mechanism, EPA would not satisfy its obligation to ensure that significant contributions to downwind nonattainment and maintenance issues are addressed by eliminating emissions commensurate with full deployment of the selected control strategy. Excess allowances that result from failing to account for generation-shifting could allow some covered EGUs to garner enough credits to comply with even the enhanced, 3-to-1 ratio when they exceed their backstop daily emission limits. Thus, the backstop limits would not necessarily ensure elimination of significant contributions on a seasonal basis and would not obviate accounting for generation-shifting when setting budgets.

Response:

Dynamic Budgets are intended to operate off the most recent observed and reported data to determine the most representative profile of the fleet. This in turn allows the EPA to appropriately calibrate the state emission budgets to reflect the Rule's identified Step 3 stringency. The methodology of including projected generation shifting based reductions in these estimates: 1) would unnecessarily introduce projected data into a dynamic budget component that has the benefit of operating off reported data; 2) would require EPA to make assumptions, and codify those assumptions into budgets, about the fleet (via modeling) for many years out where the uncertainty around the fleet composition and market conditions is greater; 3) would be somewhat redundant with the dynamic budget methodology that already picks up this fleet turnover (albeit with a lag); and 4) would be somewhat mooted by the bank recalibration and daily backstop rate mechanisms that reduce the risk of the hypothetical posed by commenter where banked allowances would quickly grow and sources would not operate controls.

The comment regarding dynamic budgets not being able to accommodate a unit that needs to operate at a higher capacity factor is not correct. As EPA describes in the preamble, dynamic budgets can adjust upwards. The presence of banking and a starting bank further accommodate this potential need four fossil source to operate, and emit more, in a future year. Moreover, the final rule's use of a multi-year baseline smoothes the impact of any particular high or low heat input year on future budgets – further assuaging the commenters' concern that the process would "lock in" a low heat input year. This comment is further addressed in Section VI.B.4.b of the preamble.

With regard to comments suggesting that the EPA should incorporate projected growth factors from the referenced NREL study, the EPA notes that the study projects possible growth in future electricity demand, consistent with policies that would encourage electrification, but does not contain projections for future heat input, which is the variable used in setting dynamic budgets. Given expected growth in renewable generation as well as the greater fuel efficiency of gas combined cycle units to retiring fossil fuel-fired steam units, the EPA does not consider it reasonable to assume that possible future growth in electricity demand would translate to equivalent future growth in heat input for electricity generation.

Underestimated Emissions Affect the Trading Program

Comments:

Commenter (0558) says that for certain units, the EPA's proposed Group 3 trading program revision allocates allowances to those units based on the higher of reported NOx mass emissions for the 2017 through 2021 ozone seasons. The commenter also states that the use of substitute data in the development of the EPA's proposed revision to the Group 3 trading program and the related allowance allocations is a concern because the use of substitute data tends to overestimate emissions. According to the commenter, as the future ozone season NOx allowance allocations for these impacted units are directly related to those overestimated emissions, the total number of allowances allocated for the Group 3 trading program will be inflated by an equal number of allowances. The commenter relates that this will result in overall allowance allocations for the proposed Group 3 trading program in excess of those that would be allocated without the use of substitute data. The commenter remarks that these excess allowances tend to reduce the stringency of the program, potentially reducing the downwind air quality benefits, and tends to reward the subject units for failing to fully provide representative, accurate emissions data. The commenter provided information for some units where substitute data appears overestimate emissions.

Commenter (0503) supports the EPA's proposed EGU ozone season emission budgets, stating that the proposed budgets are reasonable, cost effective, and equitable. The commenter also agrees that the new budgets would require additional optimization of pollution controls from upwind sources and would ensure beneficial near-term pollution reductions for downwind nonattainment areas, as well as long-term reductions in emissions that are necessary to attain the ozone standard.

Commenter (0758) states that the additional trading-program enhancements that EPA has proposed—which are also designed to ensure that EGUs achieve emission rates consistent with the selected controls that would eliminate significant contributions to downwind nonattainment—do not obviate dynamic budgeting. To take one example, the commenter provides that while EPA's proposal to recalibrate the banks is helpful, it does not reduce the excess allowances in unadjusted budgets: the allowance bank during each control period might not even be needed given an inflated budget. See 87 Fed. Reg. at 20,109. Further, according to the commenter, resizing the bank to a percentage of an inflated budget would only compound the problem of excess allowances in that year. As a second example, the commenter notes that the backstop daily emissions limits that reflect operation of post-combustion controls on some covered EGUs—operationalized through a 3-to-1 allowance surrender ratio—would not provide any incentive to EGUs that are not assumed to install post-combustion controls to reduce their NOx emissions; for those EGUs that are assumed to install post-combustion controls, the backstop limits would send only a weak compliance signal given the overabundance of allowances. See id. at 20,121.

Commenter (0758) asserts that the statute does not contemplate that the EPA or the states will continually check for overcontrol once they are implementing a full remedy to their significant contributions to downwind nonattainment or maintenance issues—including implementation that involves a dynamic-budgeting mechanism. The commenter provides that section 110 requires states to provide for SIP revisions "as may be necessary to take account of revisions of such national primary or secondary ambient air quality standard or the availability of improved or more expeditious methods of attaining such standard" and "whenever the Administrator finds on the basis of information available to the Administrator that the plan is substantially inadequate to attain the national ambient air quality standard which it implements or to otherwise comply with any additional requirements established under this Act." 42 U.S.C. § 7410(a)(2)(H). This subsection, which sets forth the required elements of a SIP, does not mention provisions that would relax any of the SIP's requirements. On the contrary, the commenter asserts that section 110(i) generally forbids modification of the requirements of a SIP. Id. § 7410(i). According to the commenter, the plain statutory objective is to address attainment issues—including by eliminating significant contributions to downwind nonattainment or maintenance problems—through a one-time plan; the CAA does not obligate or even typically authorize a state or EPA to weaken the provisions of a plan once air quality has improved.

This conclusion is reinforced by the statute's anti-backsliding provision, which requires EPA to continue to require controls for those areas that effectively move into attainment when a NAAQS is relaxed. See 42 U.S.C. § 7502(e). Under this provision, even if controls are no longer necessary to attain the revised NAAQS, the progress in air quality that those controls were designed to achieve must be retained—even where the controls have not yet taken effect. See, *e.g.*, *S. Coast Air Quality Mgmt. Dist. v. EPA*, 472 F.3d 882, 904 (D.C. Cir. 2006) (rejecting EPA's contention that contingency plans that had not yet been triggered under a previous NAAQS were not required under the anti-backsliding provision). By analogy, in the hypothetical situation in which a state is no longer linked to a receptor with nonattainment or maintenance issues under the 2015 ozone NAAQS, that state should remain subject to the requirements of the proposed Good Neighbor Plan, including the dynamic budgeting mechanism. This outcome is all the more imperative where EPA has not revised its assessment of the level of pollution that is harmful to health, but rather the state has simply addressed the threshold problem that led to its initial inclusion in the program.

Indeed, according to the commenter (0758), the possibility of overcontrol is entirely independent of the dynamic budget mechanism: it has always been possible that a state could become delinked from nonattainment and maintenance monitors or could move below the 1% contribution threshold, and the ongoing budgets in prior CSAPRs would still have imposed obligations on the state's EGUs. The commenter explains that a feature that more closely ties a state's budget to the selected levels of control for its operating fleet of EGUs simply holds the stringency of the control strategy constant. Although this feature could prove more effective in reducing emissions over time and thus resolving downwind nonattainment and maintenance issues than a static budget would, the ongoing effectiveness of the strategy (similar to emissions rate limitations that apply continuously and indefinitely) does not require a more exhaustive analysis of the potential for overcontrol, or repeated checking for overcontrol when setting future budgets. Put differently, the commenter asserts that the fact that the static budgets under previous iterations of CSAPR proved ineffective and thus less likely to help delink upwind states does not eliminate the possibility that those rules could also have overcontrolled, and yet EPA has never attempted to check all plausible emissions scenarios or current circumstances for overcontrol.

Nevertheless, the commenter (0758) believe that it would be prudent for EPA to examine the potential for adjusted budgets to incentivize ongoing emission reductions at EGUs that remain in operation even when a state is no longer linked above the 1% threshold to a downwind receptor struggling with attainment or maintenance. To do so, the commenter suggests that the EPA could model several scenarios in which retirements of fossil fuel fired EGUs are assumed to be higher than expected and assess the impacts of these retirements on power sector operations and emissions under the dynamic budgets, downwind air quality, and contributions from upwind states. The commenter notes that running these sensitivities could assure the Agency and stakeholders that the dynamic budgets are not likely to prompt the remaining EGUs to undertake control measures that would arguably not be needed to eliminate each state's significant contribution to downwind pollution problems.

Response:

In regards to the use of substitute data, EPA notes that its role in preset budgets is small and that its use is offset by the surrender requirement that will be higher if informed by that substitute data. The EPA notes the current methodology disincentivizes any intentional use of substitute data because 1) such units would still have an allocation shortage per ton of emissions, and that shortage would increase as operation increases, and 2) the allocation methodology is divorced from the budget methodology – meaning any assumption in greater emissions for the state budget doesn't necessarily imply that those extra allowances would flow to these units (EPA's allocation methodology generally results in units with higher emission rates have a lower allocation to emissions ratio).

For the EPA's response to comments concerning the Agency's legal authority and alleged overcontrol, see Preamble Sections III and V.D.4.

5.2.1.3 Assurance Levels

Comment:

Commenter (0554) supports EPA's proposal to allow the variability limit for a state to rise to a level commensurate with any percentage increase in heat input of the state's affected EGUs that exceeds the heat input assumed in calculating the state's budget, writing that this increases flexibility but remains within the bounds of the approach that has worked well before.

Response:

Final assurance provisions for the CSAPR NOx Ozone Season Group 3 Trading Program are discussed in section VI.B.5 of the preamble to the final action.

Comment:

Commenter (0506) states that EPA should not finalize the proposal to revise variability limits to be the higher of 21 percent of the percentage by which the actual total heat input of the state's EGUs exceeds what was assumed for the state budget for that control period, because the revision could allow sharp increases in emissions and lead to larger dynamic budgets. The EPA acknowledges that advance knowledge of the assurance level can be useful to sources, and yet also acknowledges "that a state's actual total heat input for a control period is not known until after the end of the control period[.]" 87 Fed. Reg. at 20,120. Commenter states that the new methodology for determining variability levels does not introduce any meaningful additional operational flexibility for covered source since unit operators will not know how actual heat input compared with estimated heat input during a control period until after the end of the control period. Commenter further states that the new methodology could allow for potentially sharp emissions increases in a given control period because this new feature would undermine the ability of the budget to function as a limit. There is no mechanism that would limit total heat input in a state, aside from the program-wide cap on allowances. As long as the units in a state can acquire enough allowances to account for their emissions, there is no limit on what the state's actual heat input - and thus the state's variability limit - could be. Commenter states that emissions increases allowed by the new methodology would not only have negative effects on air quality and downwind areas, but they would also lead to larger state budgets when EPA calculates future year emissions baselines. The EPA explains that "the proposed revised variability limits would be well coordinated with the budgets established using [the] dynamic budgeting process," under which "each emissions budget would be computed using the latest available reported heat input, which . . . would be the heat input for the control period two years before the control period whose budget is being determined[.]" 87 Fed. Reg. at 20,120. Since the actual heat input of a state's covered sources would be used to calculate the state's budget for the next control period, and since there would be no actual limit on the total heat input, the new methodology allows for state budgets potentially much larger than needed for upwind states to eliminate their significant contribution to downwind nonattainment and maintenance problems. Commenter believes it is not EPA's intent in proposing the dynamic budget provisions that they lead to larger budgets than the budgets proposed for the 2023 and 2024 control periods. The new methodology for setting a variability limit is not beneficial in any way, would undermine the goals of CSAPR, and should not be part of the final rule.

Response:

For the EPA's response to this comment, see Section VI.B.5 of the preamble.

Comment:

Commenter (0758) states that because crypto-generators that move entirely away from the sale of electricity to the grid are no longer generating electricity needed to meet variable demand, their portions of state budgets should not amplify the variability limits intended to provide flexibility to supply reliable electricity in all states. The commenter states that the EPA should remove the portions of the state budgets it allocates to crypto-generators from the calculation of a state's variability limit (and assurance level).

Response:

The EPA finds that it is not necessary at this time to consider modifying the rule's provisions for calculating variability limits to address the commenter's concern because at present the concern is purely hypothetical. The EPA is unaware of the existence of any units within the Group 3 trading program's geography that are being used to supply cryptocurrency operations and that have disconnected from the electricity grid. See also response to comment in Section 5.2.1.1 of this document.

5.2.1.4 Bank Recalibration

Comments:

Commenter (0373) requests that the EPA eliminate the limits on unused NOx allowances. The commenter explains that the annual recalibration requirement would have the following adverse effects on coal-fired generation:

- It could disincentivize early access NOx emission reductions through cost-effective control measures, including maximizing NOx removal levels achieved by SCR and other emission control measures. If banked allowances are eliminated every year, utilities may take a use-or-lose approach because a substantial portion of their unused allowances would be worthless.
- It could have adverse reliability impacts by forcing the idling of coal generation during periods of peak electricity demand. These impacts could occur because the proposed limit on banked allowances could substantially reduce the number of surplus allowances to cover NOx emission increases caused by spikes in electricity demand. If a coal-fired generator cannot secure a sufficient number of banked allowances to cover increased emissions due to peak electricity demand, the only two options would be to idle the unit or continue to run the unit and be subject to an enforcement action. According to the commenter, the only other option to avoid enforcement would be for the operator to obtain a Section 202I order pursuant to the Federal Power Act. Such extraordinary relief, however, is not necessarily guaranteed and requires considerable resources and coordination.
- It will be more difficult, if not impossible, to operate a coal-fired unit without an SCR. For example, a tight NOx allowance market could effectively preclude electric utilities from complying by purchasing NOx allowances instead of installing SCR. The elimination of this alternative compliance option means that even coal-fired units equipped with SNCR systems or other NOx control systems may not have the option to cover any allowance shortfall by purchasing allowances. Because the installation of SCR will likely be cost prohibitive for many coal units, a utility may have no choice but to retire a coal-fired power plant if its only compliance option is to install SCR.

Commenter (0354) writes that the allowance bank calibration would inappropriately reduce the available NOx allowances in the market and punish EGUs that operate in a manner that provides excess NOx allowances. The commenter explains that EGU operators in certain areas may elect to hold NOx allowances to use when they may be most needed (i.e., when electricity demands are highest.)
Additionally, the commenter (0544) notes that the seasonal NOx allowance market lacks liquidity. Even in circumstances where it appears that sufficient allowances are available, what

the commenter has observed in the market is that the holders of most of these allowances have policies not to sell them. Many regulated utilities are not incentivized to optimize their allowance positions and thus do not think of their allowances as an asset to be monetized, but rather a potential authorization to emit at some point in the future. According to the commenter, the simple number of allowances that are currently banked does not adequately inform the availability of allowances that could be purchased for compliance.

Approaching the June 1 compliance deadline for the 2021 control period, the commenter (0544) states that the NOx allowance prices were observed trading up to $55,000 per ton. Limiting the allowance bank to 10.5 percent of the overall state budgets will further drive-up allowance prices, which are already far higher than EPA assumed in this rulemaking. The commenter contends that constraining the allowance market in this way could foreseeably result in a scenario where entities that require allowances for compliance cannot purchase them, at any cost.

Commenter (0500) states the proposed conversion of existing Group 2 allowance banks, reductions in allocations, and future bank recalibrations will create liquidity issues with regard to procuring Group 3 allowances at any price. The commenter adds that the reduction of supply will disincentivize allowance trading as covered parties will need to hoard any allowances they may have regardless of the market price to ensure some degree of operational assurance in future years. Group 3 Seasonal NOx allowance prices have already significantly increased under last year's Revised CSAPR Update, and the market is already dealing with low allowance supply issues. According to the commenter, the uncertainty around future bank holdings and allocations have pushed prices well above the prices used in EPA's assessment of the Proposal, and the current CSAPR Group 3 market is trading at over a 566% price increase year-over-year.

Commenter (0341) writes that EPA's proposed bank recalibration methodology is flawed because it does not take into account that 2021 ozone season allocations were prorated. The commenter states that emissions for the 2021 ozone season would have been 107% of the budget if the Revised CSAPR Update were in effect on May 1, 2021.

Commenters (0282, 0272) express concern about EPA's proposal that bank adjustments be completed in the middle of a compliance period. At least one commenter (0282) believes that it is beneficial for entities to approach an ozone season knowing exactly how many allowances are available, so they can make informed decisions about trading as the ozone season progresses. The commenters state that adjusting the pool of allowances available for compliance, when the season is more than 60% complete, may cause unforeseen complications and recommend two potential solutions. The commenters state that the preferable solution is that the EPA announce the bank adjustment on August 1 but apply it for the following compliance period, and the alternative recommendation is that the EPA publish the preliminary adjustment prior to May 1, based on the agency's more informed and intimate knowledge of the bank. According to the commenters, even if the EPA does not actually withdraw allowances from accounts until August 1, a unit owner will have a much better idea of how many allowances will be available and can make market decisions accordingly.

The commenter (0330) also states the bank recalibration will begin with the 2024 compliance period and would occur sometime after June 2nd and no later than August 1 of a given compliance period. Thus, the bank recalibration for the 2025 compliance period may not occur until August 1, 2025, just 2 months before the end of the compliance period. Unless a utility is highly confident that their initial allocations will be sufficient to cover its compliance obligation, absent any banked allowances, it is unlikely they would choose to sell 2025 and earlier vintage allowances any earlier than August 1, 2025.

Commenters (0500, 0530) urge EPA to consider modifications to the proposed timeline so that the recalibrations do not occur within an ozone season. Commenter (0500) acknowledges that calibrations are associated with the preceding control period, though this still creates risk as operators are entering an ozone season without knowing how many banked allowances may be forfeited mid-season. The commenter requests that the EPA consider revising the rule and announce the bank adjustment on August 1, as proposed, but not apply the recalibration until the following ozone season. The commenter states that they would also support EPA re-evaluating the need for an annual recalibration of allowance banks considering achieved emissions reductions. Commenter (0530) states that a five-month compliance planning window (assuming the Proposal is finalized in December 2022) will not provide adequate time for a stable allowance market to develop. A longer period is needed to develop and implement compliance procurement strategies and to allow an effective market to develop. The commenter notes that the CSAPR Group 3 allowance prices have already spiked, with current market transactions at prices over $30,000 per ton as allowance scarcity has already become a critical concern. The Agency only needs to look at the unprecedentedly short and aggressive phase-in of the Revised CSAPR Update rule and the market issues it created as the rule was not even effective until June 29, 2021, well after the 2021 ozone compliance season began on May 1, 2021.

Commenter (0368) writes that the proposed rule will effectively eliminate trading, since short term limits eliminate the value of holding allowances and will lead to reduced allocations. The commenter adds that the banking ceiling prevents a source from accumulating allowances for future use, and by restricting the ability of the trading program to avoid costly or infeasible controls since other sources can overcontrol, the proposed rule reduces flexibility and kills a core component of the trading program.

Commenters (0329, 0411, 0430, 0515, 0539, 0553, 0544) claim, in general, that EPA's proposal to limit banking of allowances to 10.5% (or half the assurance level) restricts the effectiveness of the established NOx budget trading program – *i.e.*, it does not consider the full aspect of prudent allowance management and the need to assure that there are sufficient unused allowances held by individual EGU owners and available within the region to assure a viable and liquid allowance market. The commenters urge the EPA not to impose a restriction on allowance banking.

Commenter (0553) disagrees that any restriction in allowance banking is required. According to the commenter, EGUs planning for compliance with ozone season NOx Budget Trading Plan requirements under the CSAPR programs requires a long-term strategy that considers forecasts for future operation, maintenance cycles for generating units and control equipment, anticipated changes in fuel supply and pricing, and availability and price of allowances, among many considerations. The commenter further notes that this planning process has become even more complicated under the 2021 Revised CSAPR Update Group 3 program because of the stringency of the requirements and the impact on the allowance market. The commenter acknowledges that each EGU owner will establish its own prudent process for managing the supply of allowances, but this may typically include developing a budgeted allowance position that looks out over the next four or five years. According to the commenter, these internal processes will help shape decisions on opportunities to reduce allowance consumption to provide banking for future years, opportunities to place allowances on the market, and any need and timing for purchase of additional allowances from the market.

Commenter (0302) requests that EPA abandon the concept of dynamic budgets and allowance bank recalibration. The commenter states that dynamic budget and annual allowance bank recalibration create unnecessary regulatory uncertainty. The commenter states that, because the budget and the allowance bank will be revised yearly, they will have little time to make any necessary adjustments to comply with future allocations. This will be further complicated by potential allowance price volatility arising from annual readjustments of the budgets. With yearly recalibrations, allowance price volatility will continue throughout the program, thereby injecting significant uncertainty into electric generating companies' planning processes.

Commenter (0782) states recalibration of banked allowances devalues what is essentially a currency between regulated entities and will disrupt the decision-making and markets for allowances. The annual recalibration disincentivizes affected EGUs from converting to natural gas. The commenter also states the proposed annual recalibration of banked allowances (to no greater than 10.5 percent of the sum of the state emissions budgets, or half of the sum of the sta'es' proposed minimum variability) raises procedural due process concerns because the transferability of allowances makes allowances a valuable asset between private parties.

The commenter (0782) notes that banking of allowances encourages early reductions, provides affected sources with certainty, and creates compliance flexibility. Recalibration of banked allowances devalues what is essentially a currency between regulated entities and will disrupt the decision-making and markets for allowances. The commenter contends that a liquid trading market for allowances is important for the continued success of a trading program that reduces emissions and reduces compliance and implementation costs. According to the commenter, the annual recalibration of allowances from the market could negatively impact market liquidity and result in rising costs for all affected units. Annually skimming banked allowances down to 10.5 percent of the state emissions budgets may also create unstable allowance pools and reduce the incentive to retire units as trading revenues offset costs. Further, the commenter states that it is unclear from the proposal how allowances will be allocated to units undergoing natural gas conversion. The annual recalibration disincentivizes affected EGUs from converting to natural gas. EGUs converting to natural gas would only reap the benefits of conversion for one year because EPA would subsequently recalibrate any banked allowances earned from the conversion. Also, because EPA allocates allowances partly on heat rate averages, if an affected source is not operating for a year or multiple years due to a conversion, the heat input during that year or partial year will be zero and consequently understate the heat input average that should be used to determine allowance allocations. According to the commenter, it is unclear whether affected sources will be able to bank allowances during a conversion year(s) if the unit is not operating.

Commenter (0289) claims that the cap on the allowance bank of 10.5 percent of the total Group 3 budget.is arbitrary and recommends that EPA evaluate how the level of banked allowances impacts the cost for allowances and show why the value it selects is able to both account for variability in electricity demand from year-to-year and keep allowance prices just high enough to compel cleaner operation from the affected units as intended by the newly proposed provision.

Commenter (0395) states the annual recalibration of carry-over banked allowances to 10.5% across the program could dramatically discourage trading and could actually encourage under control at units with the potential to create allowances in a "use-it-or-lost-it" reaction to EPA's limit. This annual removal of banked allocations would also significantly limit a region's ability to deal with an extreme summer or similar high-demand event during an ozone season. This could lead to idling of units during the peak demand season, causing reliability issues. The EPA has not provided sufficient justification to link the changes proposed to the banking system to downwind ozone concentrations.

Commenters (0396, 0554) state, in general, recalibration of banked allowances will penalize those taking the very actions EPA seeks to achieve with the Proposal and EPA provides little to no justification for the need. Commenter (0396) adds that other than an anecdotal statement regarding EPA's concern that banks will slowly grow to the point that allowance prices drop lower than EPA would prefer, EPA has not explained why banking should be constrained. Since banked allowances represent early and more significant reductions than EPA originally deemed necessary to achieve its environmental objectives, commenter maintains that banking allowances should be rewarded, not penalized.

Commenters (0409, 0431) assert that it is plainly not realistic to pretend there will be any allowance surplus, particularly enough to permit changes in control device operation. Regardless of the sufficiency of allowances, enforceable permit requirements require continuous operation of SCRs and SNCRs at optimized rates, regardless of allowance shortages. The commenters contend that, any banked allowances will be needed to make up for projected budget shortfalls. The commenters note that EPA has found a lack of evidence that a large number of sources are turning off SCRs.

Commenter (0519) provides that this [overcontrol] problem is made worse by EPA's recalibrated allowance bank cap using these dynamic budgets. The commenter explains that banked allowances represent emissions reductions by a unit in excess of the required threshold. As state budgets continue to lower under EPA' s dynamic budgeting approach, bank sizes will also be artificially reduced, attributing fewer emissions reductions to all banked allowances and preventing units from obtaining credit for their reductions. The commenter adds that this approach allows EPA to ignore emissions reductions under the Good Neighbor Plan that would be in excess of state obligations under CAA § 110(a)(3)(D)(i)(I) by effectively writing them off. According to the commenter, the overcontrol created by these provisions is unreasonable and exceeds EPA's authority under the Act.

Commenters (0499, 0533) add that the EPA's proposed annual recalibration of the allowance bank to either 10.5 percent of the state budgets or half of the sum of the states' proposed minimum variability limits further constrains an already limited allowance market and may prevent units from acquiring sufficient allowances to provide for normal operations. In the final FIP, the commenters recommend that the EPA provide a clearer explanation of how the recalibration of the bank will work.

Commenter (0297) states the annual recalibration of allowance banks to 10.5 percent of the sum of state emission budgets takes away needed flexibility to account for disruptions in electricity supplies during the ozone season and disincentivizes generation shifting. The justifications for why the annual bank recalibration feature is necessary focus too heavily on issues in the earlier trading programs and do not allow for future flexibility. In regard to the first justification, the commenter notes that the emission budgets are significantly more stringent for the Proposed Transport FIP; adding that with the addition of the secondary emission limits, the need to reduce the number of banked allowances to deter "bad behavior" by some EGUs is no longer an issue. In regard to the second justification, the variability of heat input of affected units over past years is not indicative of future affected units' operations due to the significant increases in the amount of generation from intermittent sources on the grid; adding a target bank size that can accommodate an increased variability in heat inputs is required. The commenter contends that secondary emission limits and dynamic budget allocation provide a level of emissions control that will allow EPA to maintain a target bank of 21 percent of the sum of the state emissions budgets with no bank recalibration required to maintain control stringency. Furthermore, the commenter worries that the proposed annual bank recalibration feature raises longer term reliability concerns – specifically, the constant annual reduction of banked allowances could result in too few surplus allowances available to cover potential future spikes in demand. In conclusion, the commenter suggests EPA recalibrate the allowance banks in line with the approach for the Revised CSAPR Update — specifically, set the target bank amount at 21 percent of the overall allowance supply and remove the annual recalibration of the allowance banks.

Commenters (0409, 0431) state predicted state budget shortfalls are a key indicator that routine bank recalibration is unwarranted. The commenters state that routine bank recalibration was not used in past ozone transport programs and will cause emission reductions that are not necessary to attain or maintain the 2015 Ozone NAAQS in downwind states. More specifically, the commenters oppose routine bank recalibration for the following reasons: Foremost, routine bank recalibration is not necessary to maintain the stringency of the CSAPR Program. Second, commenters believe that exorbitant Group 3 allowance prices demonstrate future program stringency, noting that Group 3 allowance prices have risen to over $25,000 and these increases will continue if the state budgets are reduced as proposed, and/or as a result of dramatic budget cuts. Third, annual removal of banked allowances cuts against incentivizing utilities to improve NOx emissions. Fourth, routine bank recalibration was not used in past ozone transport programs. Finally, commenters maintain that bank recalibration will cause emission reductions that are not necessary to attain or maintain the 2015 Ozone NAAQS in downwind states. In general, commenters support removal of routine bank recalibrations from the Proposed FIP. The commenters contend that it is not needed to assure program stringency or to reduce upwind states contribution to a level below the appropriate threshold. In support of their position that routine bank recalibration is not necessary to maintain the stringency of the CSAPR Program, commenters (0409, 0431) provide that, Table 9-8, entitled “EGU 2023 Ozone Season Emission and Allocations by State” in Section VI supra illustrates allocation shortfalls in six of nine example states in 2023. The commenters note that three states without shortfalls only had minor surpluses. The overall 2023 allowance shortfall for the nine states together is 6,310 allowances. The commenters add that the shortfall in 2026 is even more egregious, likely the result of generation shifting, based on our technical experts’ results in Table 9 -9 (Table 9-9. Kentucky and Texas EGU 2026 Ozone Season Emissions and Allocations).

In support of their position that exorbitant Group 3 allowance prices demonstrate future program stringency, commenters (0409, 0431) report that, since the Proposed FIP’s release, Group 3 allowance prices have risen to $ 32,750. The commenters add that one allowance authorizes the emission of one ton of NOx and pricing is indicative of a tightly budgeted program without surpluses.

In support of their position that annual removal of banked allowances cuts against incentivizing utilities to improve NOx emissions, commenters (0409, 0431) state that past transport trading programs allowed banking as a benefit to encourage operators to explore means to reduce NOx further. The commenter notes that the EPA acknowledges this benefit in the Proposed FIP. In the Revised CSAPR Update Rule, the commenters add that the EPA lauds the flexibility of a mass-based trading program. A key feature to maintaining this flexibility is banking.

In support of their position that routine bank recalibration was not used in past ozone transport programs, commenters (0409, 0431) state that routine bank recalibration was not used in past ozone transport programs. The commenters state that EPA found other means of addressing bank stringency on a need-basis. The commenters provide that the EPA has regularly recalibrated allowance banks with each iteration of the program. The Program was last recalibrated last summer 2021. It was previously recalibrated in 2017. The commenters state that these periodic recalibration events removed accumulated, banked allocations. Banks are already depleted.

In support of their position that routine bank recalibration will cause emission reductions that are not necessary to attain or maintain the 2015 Ozone NAAQS in downwind states, commenters (0409, 0431) state that, like dynamic budgeting, EPA’s model does not include reductions due to bank recalibration. According to the commenters, bank recalibration is unnecessary to achieve the goals of this rulemaking and creates another overcontrol scenario.

Commenter (0411) also believes that there should be no cap on the allowances carried over from year-to-year, as it incentivizes allowance holders to retain unused allowances to provide for future operational needs when they might otherwise have sold some of the excess allowances. The commenter suggests a flush bank should be viewed as a positive sign of a working allowance market – capping the bank as proposed creates a strong incentive to retain excess allowances rather than selling excess allowances and results in the potential over-control of the market and emissions. Additionally, the commenter states a cap this low (10.5%) also conflicts with the intended flexibility of an allowance trading program by creating a “use them or lose them” allowance scenario. Finally, according to the commenter, the cap will also lead to the potential for over-control as the budget was developed based on emissions needed to meet the standard.

Commenter (0414) states the proposed annual recalibration requirement could effectively disincentivize affected electric utilities from achieving early excess NOx emission reductions through various cost-effective control measures, including generation shifting to renewable energy or other zero- or low-emitting energy sources. In particular, the commenter states that, if a number of banked allowances are simply eliminated every year, electric utilities may take a "use-or-lose" perspective based on the fact a substantial portion of their unused allowances for the current control period will be eliminated anyway. The commenter provides that this further reflects the fact that an annual bank recalibration requirement will in realty not accomplish the CAA objective of lowering NOx emissions from upwind states that are significantly contributing to downwind ozone nonattainment in other states.

Commenter (0414) also notes that it is also based on questionable assumptions on the year-to-year variability in heat input. The commenter states that variability in heat inputs from past years is not determinative of future variability when the grid will be operating with a generation mix much more heavily dependent on intermittent, non-dispatchable resources. The commenter adds that an adequate bank of allowances is necessary to provide the flexibility for fossil units to meet electricity demand during unusual events that require increased reliance on fossil-based, dispatchable units.

The commenter (0414) states that the proposed requirement to limit the total amount of banked allowances each year also could have adverse electric grid reliability impacts by forcing the idling of affected EGUs during peak periods of electricity demand. These impacts could occur because a hard cap on banked allowances could substantially reduce the number of surplus allowances that would be available to cover NOx emission increases resulting from unanticipated future spikes in electricity demands. According to the commenter, if an electric utility cannot secure a sufficient number of surplus banked allowances to cover increased emissions due to abnormally high peak energy demand, the only two options would be to idle the EGU and thereby fail to meet demand or continue to run the unit and be subject to a CAA enforcement action.

Commenter (0500) state that the banked allowances would no longer be able to provide the amount of NOx emissions offset benefit assumed at the time of original banking. According to the commenter, this creates uncertainty as allowance holders will no longer be able to determine the value of a banked allowance until EPA assesses and recalibrates the banked allowances after each season.

Commenter (0521) states allowance recalibration, in essence, is a form of taking, and penalizing previously controlled emissions without proper notification and justification. More specifically, commenter states provisions in the proposed rule should not penalize affected units that banked past seasonal allowances for future years at the cost to their electric utility customers; arguing this, in essence, is a form of taking, taxation, or penalty without proper written notice or justification. According to the commenter, their customers paid to control emissions during previous ozone seasons, and this "banking" made allowances available for sale or future compliance requirements. Commenter explains that allowances in the Group 2 market are sold for $2,500-$3,000 per allowance, while Group 3 allowance market is much higher due to the scarcity of available allowances. Additionally, commenter (0521) claims the proposed dynamic reallocations provision removes certainty for generation owners and Regional Transmission Operators (RTOs), and annual dynamic reallocation is problematic to owners/operators of generation assets and reduces certainty for affected united under the program

Under the Proposed Rule EPA would recalibrate state NOx emissions budgets annually, adjusting for new retirements, new units, and generation shifting—beginning in the 2025 control period, based on 2023 (single ozone season) data. Commenter (0544) states automatic adjustment of the allowance bank fails to take into consideration the realities of this seasonal NOx allowance market. Unlike a consumer goods market-based system where supply can be generated when the market demands it, NOx allowances cannot merely be generated at will. There is a finite supply of allowances, and a finite set of conditions under which new allowances may be created (*e.g.,* unit shutdown).

Commenter (0544) states that, along with the dynamic adjustments to state NOx emissions budgets, beginning in the 2024 control period, the proposed rule would limit the number of banked allowances to a target level of 10.5 percent of the sum of state NOx emissions budgets on an annual basis. 87 Fed. Reg. 20,105. The commenter contends that this automatic adjustment of the allowance bank fails to take into consideration the realities of this seasonal NOx allowance market. Unlike a consumer goods market-based system where supply can be generated when the market demands it, the commenter notes that NOx allowances cannot merely be generated at will. There is a finite supply of allowances, and a finite set of conditions under which new allowances may be created (*e.g.,* unit shutdown).

Commenter (0546) states the lack of any significant quantity of surplus allowances will significantly constrain the ability to continue to operate the unit during the 2026 or subsequent ozone seasons. The commenter questions why the two mechanisms – (1) retirement of a unit, or (2) controlling emissions from a unit to a greater extent than was contemplated by EPA in establishing the relevant state emission budget, by which an EGU operator could generate surplus emission allowances, under both the existing and prior versions of the CSAPR trading programs, are not included as an option under the proposed rule. The commenter asserts that the proposed annual allowance bank recalibration is one of three aspects of EPA's Proposed FIP, when considered together, leave no obvious and sustainable source of surplus emission allowances in 2026 or beyond, will constrain a source's ability to supplement its ozone season allowance allocation via the use of banked allowances if needed. The commenter notes that it is worth noting that the other two aspects discussed include: the presumed SCR retrofits at certain units, for the purpose of establishing state NOx emission budgets for the 2026 and subsequent ozone seasons, which will significantly reduce state NOx budgets and the proposed treatment of idled, suspended, and retired units in the dynamic budget process, which would eliminate a unit from the state NOx budget two years following any ozone season in which the unit did not operate, along with the elimination of allowance allocations to such units two years after the last ozone season in which the unit operated.

Commenter (0547) states limited carryover and recalibration of banked allowances is overly stringent. The commenter states units may be forced to shut down (jeopardizing grid reliability) due to the lack of allowance. The recalibration process will also result in real losses to the allowance holders when they are forced to forfeit these valuable credits. The EPA states that "the calibration procedure would not erase the value of unused allowances for the holder, because the larger the quantity of banked allowances that is held in a given account before each recalibration, the larger the quantity of banked allowances that would be left in the account after the recalibration for possible sale or use in meeting future compliance requirements." The commenter disputes this assertion because the recalibration process will result in actual losses for the owners of banked allowances. Banked allowances have real value, and it cannot be assumed that holders will be adequately compensated by any potential increase in value to leftover allowances simply due to increased scarcity. For these reasons, the commenter requests that the EPA eliminate the recalibration process for banked allowances from the Proposed Transport FIP.

Commenter (0550) states bank recalibration would require unnecessary reductions and limitations, which constitutes overcontrol. In the Proposed FIP, the commenter notes that the EPA states that its allowance bank recalibration is necessary to "prevent any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods." Even if EPA later justifies "stringency" of controls as a synonym for "significant contribution," which it has not, the commenter states that the EPA's stringency goal is already accomplished through the assurance provisions. The commenter contends that the assurance provisions necessarily limit a state's, and the corresponding sources' in a state, freedom to emit materially in excess of its allocated budget and simply rely on banked allowances to make up the difference. Although states may exceed this assurance level, exceedances require an additional 3-for-1 allowance surrender. This surrender obligation by itself reduces any "surplus of allowances" that could become an issue if sources in a state attempt to ignore the overall stringency of the emission budgets that reflect EPA's determination of available cost- effective reductions. The commenter acknowledges that the EPA recognizes this, explaining that "[a]lthough the [existing] programs do not directly limit either trading or banking of allowances, 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." The commenter states that no further assurances, such as a banked allowance recalibration, are necessary to avoid this risk. According to the commenter, the EPA's efforts to further limit sources beyond what is necessary, *i.e.*, beyond the amount EPA has determined is their "significant contribution," by taking away allowances the sources have earned through over-compliance constitute overcontrol and are unlawful.

Commenters (0551, 0782) provide that the EPA is proposing annual recalibration for two reasons. First, in the transition from CSAPR to the CSAPR Update, EPA set a target bank of 1.5 times the sum of the variability limits and in transition from the CSAPR Update to the Revised CSAPR Update, EPA set a target bank of 1.0 times the sum of the variability limits. In each transition, EPA found the initial bank "proved larger than necessary, as total emissions of all sources in the program were less than the budgets." According to the commenters, it is inappropriate for EPA to apply this rationale to the proposed CSAPR rule for the 2015 ozone NAAQS because EPA has introduced several new components to its existing CSAPR framework (*e.g.*, the backstop daily emissions rates) that should preclude EPA from applying the same assumptions from less stringent prior CSAPR rules.

Commenters (0551, 0782) state, in general, recalibration is designed to require reductions that cannot be justified on an overall tonnage basis and that would not be necessary to address NAAQS nonattainment or maintenance problems. The commenters also state whether an initial bank established during a transition period from one program to another is too large does not speak to the need for sources to establish banked allowances for themselves for future use under individualized circumstances. According to the commenters, if total emissions of all sources in the program are less than the state budgets, than the availability of additional banked allowances is irrelevant, as significant contribution will have been addressed.

Commenter (0551) suggests that the EPA might be able to refine its bank recalibration provisions to prevent them from resulting in over-control. Rather than automatic annual reductions of banks to 10.5% of variability limits, the commenter states that the EPA could engage in an annual review of whether significant contribution remains in each state, and only recalibrate banks in states where significant contribution remains. The commenter adds that the EPA could include additional safeguards to ensure that bank recalibration will not create compliance problems for individual sources especially where such sources may not be significantly contributing to downwind nonattainment or maintenance problems.

Also, the commenter (0412) adds that the “allowance bank recalibration” to maintain a limited 10.5% is not needed due to the stringency of the Proposed Rule, but if maintained limit should be raised significantly to at least 20%.

Second, commenters (0551, 0782) provide that the EPA states that "an analysis of year-to-year variability of heat input for the region covered by this proposed rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95% confidence." The commenters add that the EPA explains that using variability analyzed at the level of the overall region to set a target level for a bank is logical because the variability will apply at the level of the overall program, as opposed to individual states. The commenters contend that it is inappropriate for EPA to recalibrate annual emissions budgets due to a "regional" variability rate of up to 10.5% because this Proposal is not "regional." Rather, for the first time, EPA is including Western States in a CSAPR rulemaking. The commenters recommend that the EPA recognize that there are unique issues related to ozone formation in Western States, such as significant discrepancies in air quality modeling compared to Eastern States. Thus, according to the commenter, it would be inappropriate to treat Western States and Eastern States as one "region" for purposes of the annual heat input analysis.

The commenter (0541) also states that states that are not linked in 2026, including Alabama, have been modeled to no longer affect any downwind monitors. Those states will have already met their obligations under the “good neighbor” provision and should not be further constrained by EPA; however, the result of the annual bank recalibration is the overcontrol of that state’s collective bank. The commenter recommends that EPA remove states that are not linked in 2026 from the bank recalibration process (along with all other “enhancements” which

EPA only justifies by linkages in 2026) or leave those states in CSAPR Group 2 or move them back in 2026 after meeting their "good neighbor" obligations.

Response:

The EPA responds to comments on the bank recalibration provisions in Preamble Section VI.B.6.

With respect to comments claiming that the bank recalibration provisions are not needed because the EPA can rely on periodic bank adjustments as performed in in 2017 and 2021, the EPA disagrees. The commenter has confused the bank recalibration provisions being established in this rule with the provisions used to establish appropriately sized initial allowance banks in the transitions between rules that are promulgated to address different NAAQS. Unlike those transitional provisions, the bank recalibration provisions are being established in this rule to sustain over time the incentives needed to ensure that states' Good Neighbor obligations with respect to the 2015 ozone NAAQS continue to be met. Unlike the bank recalibration provisions, the transitional provisions do not address the need for program design enhancements to ensure continued satisfaction of Good Neighbor obligations for a given NAAQS.

With respect to comments asserting that the selection of a target bank percentage of 10.5 percent should not simultaneously consider Western and Eastern states, the EPA disagrees. The commenter notes that ozone formation in Western states has "unique issues" but fails to explain any relevance of that statement to selection of a target bank percentage for a trading program that encompasses both Western and Eastern states. Under the trading program, allowances are fungible across sources in all covered states. The EPA's analysis of heat input variability supporting selection of 10.5 percent as the target bank percentage appropriately included both Western and Eastern states.

With respect to comments asserting that the target bank percentage of 10.5 percent is too low because an analysis performed by the commenters identifies a shortfall of approximately 6,000 allowances across nine states in 2023, the EPA finds the comments unpersuasive for several reasons. First, the commenter provided insufficient detail to enable the EPA to ascertain how the alleged shortfall was calculated. Second, the trading program covers 22 states, not the nine states the commenters say they evaluated, and an alleged shortfall in a subset of states, even if it were analytically supported, would not demonstrate a shortfall for the entire trading program. The trading program's variability limits are designed to accommodate instances where generation and emissions shift between states to address year-to-year operational variability. Third, the EPA's own analysis indicates that the sum of the 2023 state emissions budgets in the final rule in fact is within 500tons (0.24%) of the reported 2022 emissions for the 22 states covered by the program, a difference that is readily explainable by changes in the EGU fleet between 2022 and 2023 as reflected in the EPA's calculation of the 2023 state emissions budgets (See document titled "2022 Unit and State-Level Ozone Season NOx Data" in the docket for this final rule).

5.2.1.5 Backstop Emissions Rate

Comments:

Commenter (0332) states the EPA should include certain changes to enhance compliance flexibility for EGUs. The EPA should incorporate several additional flexibilities and adjustments to the proposed program to allow for the successful implementation of both the emissions trading program and the ongoing clean energy transformation of the electric sector. These include potential alterations to the EPA's proposed maximum daily rate for individual EGUs; implementation issues surrounding the Agency's novel dynamic budgeting; multi-unit averaging; expanded banking and conversion of banked allowances; and other potential implementation changes.

Commenter (0302) states that its units should not be subject to the new daily limit, claiming that there are no environmental benefits gained by imposing redundant and burdensome NO_X emissions limitations on well controlled affected units. Based on values provided by this commenter, its units have existing enforceable limits that are far below the proposed daily limit of 0.14 lb/mmBtu. The commenter explains that, while it would appear that a higher daily limit would not cause compliance issues for these specific units, there is a high likelihood that a unit starting up or shutting down will have a daily emissions rate above the proposed 0.14 lb/mmBtu value. The commenter requests the EPA provide an exemption from the daily 0.14 lb/mmBtu NO_X emissions limit for units that already have stringent federally enforceable NO_X emissions limitations in place, which can only be met by continually running each affected unit's SCR during the ozone season. If the EPA moves forward with the daily 0.14 lb/mmBtu NO_X emissions limit, the commenter requests that existing units with SCRs and federally enforceable limits that require their continuous operation not be adversely penalized with a backstop limit any sooner than a unit without an SCR. The imposition of a backstop limit on these types of units should be in line with the deadline for those units that currently have no SCR installed or have failed to operate their SCRs, according to the commenter, since the limit is meant to force SCR operation during the ozone season, not to penalize units that operate their SCRs throughout the ozone season. Finally, Commenter (0302) requests that if the daily rate of 0.14 lb/mmBtu is imposed, NO_X emissions data should not be bias adjusted and should not include any substituted data due to emissions monitoring issues, noting that substituted data is important for a mass-based emissions program but is inappropriate to determine compliance with an emissions rate limitation.

Commenter (0318) states that there is typically a financial cost associated with operation of the controls used to remove regulated pollutants from EGU emissions. The commenter notes that examples of these costs are for the purchase of control reagents, parasitic energy load to run the controls, and additional operation and maintenance of the control equipment. The commenter asserts that as a result, there is an economic incentive for EGUs to discontinue operating pollution controls absent an enforceable obligation to do so under a permit, regulation, or court order. The commenter notes that this has been borne out in the historical track record of EGUs participating in regional NO_x programs that do not optimize their existing controls, or that shut them down altogether, during the ozone season. Commenter provided examples include:

- A coal-fired power plant where a company spokesperson stated that, in 2015, it was much cheaper to buy allowances than run its already installed NOx controls.

- An EGU for which the EPA noted that NOx emissions "substantially increased in 2019 compared to previous years" (emphasis in original) and that this was "likely due to the erosion of the existing incentive to optimize controls (*i.e.*, the ozone-season NOx 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)."

- Several coal-fired steam EGUs shut down SCR controls after the owner and operator purchased in advance a large reserve of NOx allowances that not only covered the excess emissions, but also covered an additional 3:1 surrender requirement for exceeding the state's applicable assurance levels in the 2020 and 2021 control periods under the CSAPR Group 2 trading program.

In light of these historical examples, the commenter welcomes EPA's steps to incentivize the optimal operation of installed NOx controls on a daily basis.

Commenter (0352) states that EPA should require additional NOx allowances to be surrendered by large coal fired EGUs in order to prevent emissions from increasing by using saved allowances on severe ozone days. The commenter explains that hot days require more power generation and thus act as an incentive to not run post-combustion controls when ozone concentrations are the highest. Using saved allowances on exceedance days authorizes the use of no controls when these controls are most needed. Seasonal trading programs assure neither daily nor high ozone day reductions consistent with the short-term ozone standard, and therefore must not be the sole mechanism for ensuring upwind transport obligations are addressed. The commenter supports EPA's proposal to require a 3-for-1 surrender ratio when a daily emission rate of 0.14 lb/MMBtu is exceeded at a large coal-fired power plant to decrease situations when allowances are used to greater extents on peak days. The commenter requests that EPA put daily limits in place to prevent an EGU from saving allowances during months when a unit is not running and expending them at a higher ratio. The commenter supports this approach in concept, but advocates for a higher surrender ratio than 3-for-1 in order to impose a stronger penalty.

Commenter (0402) supports, in general, the daily backstop limit and the timeline.

Commenter (0318) states that "EPA's proposal to require an allowance surrender ratio when an EGU exceeds the backstop daily rate coupled with dynamically adjusting downward future state NOx budgets to reflect changes in the composition and utilization of the EGU fleet and recalibrating the quantity of banked allowances across control periods to not exceed 10.5% of the sum of the state emissions budgets" can help mitigate the problem of EGU operators intentionally turning off or running less efficiently their installed pollution controls, presumably due to the easy availability of cheap excess NOx allowances. The commenter requests that the EPA include a public reporting requirement by the EGU operator when the backstop rate is exceeded. The commenter notes that Maryland includes a provision in its state regulations that if a covered EGU fails to meet its unit-specific 24-hour block average NOx rate, it must submit a report for each day above the rate. The report must include operational details during the excess emissions, identify any malfunctions or operator errors that caused the excess emissions, specify any dispatch requirements leading to unplanned operation above the unit's daily emission limit, describe all steps taken to reduce excess emissions, and provide other relevant information elements. The commenter states that this report should be publicly available so that industries and the public have a clear understanding of when and why an EGU would emit above its backstop rate.

Commenters (0272, 0282, 0367, 0503, 0506, 0510), in general, support the daily emission rate backstop provision proposed in the Proposed FIP. Commenters (0272, 0282) believe that the proposed emissions rate limit is necessary to ensure that the required emissions reductions are achieved daily, and that control equipment is operated and maintained in good working order. To address concerns about the ability of a unit to meet the daily limit during startup, malfunctions, or monitoring equipment failure, the commenter suggest the EPA revise this section to provide an option for systemwide averaging among a company's (or companies') affected sources. According to commenter (0282) this allows well-controlled units to provide a compliance margin for a unit that may be in a startup or experiencing an equipment malfunction. Commenter (0367) is concerned that rates may not be achieved when allowance prices fall. Commenter (0503) asserts that the failure to optimize air pollution controls on sources has serious local impacts on communities near the sources, in addition to the regional impacts on neighboring states from transported air pollution, and therefore, strongly supports the Proposed FIP's mass cap and daily rate backstop as an important step to addressing environmental justice concerns.

Commenter (0318) commends the EPA for proposing a 24-hour daily limit for EGUs that is intended to better ensure units with installed NOx pollution controls run those controls at optimized levels. In tandem with a daily backstop limit, the commenter also recommends that the EPA also impose a 0.08 lb NOx/mmBtu ozone season average rate to ensure that expected NOx reductions from the proposed rule are as close as possible to the modeled reductions the EPA uses for its state budget calculations.

Commenter (0324) states EPA should start the daily backstop emission limit 0.14 lbs/mmBtu with the 2023 ozone season for existing SCRs, unless starting with the 2024 ozone season can be justified more adequately than in the proposed rule. Similarly, EPA should start the daily backstop emission limit 0.14 lbs/mmBtu with the 2026 ozone season for retrofit SCRs unless starting with the 2027 ozone season can be more adequately justified. Earlier start dates for these daily limits could help nonattainment areas to reach attainment sooner.

Commenter (0328) supports EPA's Proposed FIP, including the proposed dynamic NOx budgeting process, the 10% budget limitation on banked allowances, and the 3:1 allowance surrender for excess emissions when daily average NOx emissions for coal fired EGUs exceed 0.14 lb/mmBtu. However, the commenter express concerns that high ozone monitored values in southeast Pennsylvania, which will impact future design values and Pennsylvania's ability to reach attainment, may not match EPA's modeling results due to the transport of ozone from high emitting EGUs in other states on high electric demand days (HEDDs). Commenter recommends that the 0.14 lb/mmBtu daily backstop be applied across the board to all EGUs covered by the proposed rule rather than just to coal fired units in order to reduce emissions from high emitting units which primarily operate on the highest ozone days.

Commenter (0558) states that a 3 to 1 allowance surrender rate may provide little deterrence to sources to comply with the backstop emission rate and that the surrender allowance will lessen the benefit of a backstop emission rate provision and, therefore, requests that EPA provide a basis for the selection of the 3:1 surrender ratio value. The commenter also states the proposed backstop NOx limitations may be insufficient to address SCR equipped coal fired EGU daily NOx emission control and recommends that EPA adopt a backstop NOx emission limitation for coal fired EGUs of 0.125 lb/MMBTU on a 24-hour rolling basis.

Commenter (0503) states the daily rate backstop may be too lenient to drive timely attainment of the standard. The commenter suggests that EPA either lower the daily backstop emission rate or require states to submit complementary Good Neighbor SIPs with daily emission rate limitations that are reflective of the ability of the individual units in each state to optimize the controls on a daily basis. The commenter requests that EPA revise the daily emission-rate backstop limit for coal-fired EGU's with SCRs to 0.09 lbs/mmBtu. The commenter also states the daily emission rate backstop's associated penalty may not be a sufficient disincentive and suggests EPA strengthen the surrender ratio such that it encourages units to consistently optimize the controls every day of the ozone season.

Commenter (0758) supports the limit and suggests that EPA set lower backstop daily emissions limits for coal-fired EGUs; extend backstop daily emissions limits to all EGUs assumed to install and operate post-combustion controls, and to peaking units; impose backstop daily emissions limits in 2023 (instead of 2024) for units that have already installed post-combustion controls and in 2026 (instead of 2027) for units that have not yet installed post-combustion controls; and forgo any option to avoid a backstop daily emissions limit by committing to retire at a later date.

Commenter (0318) states that under this proposed FIP, a $7,500 per ton of NOx reduced cost threshold, a 10.5% banked allowance limit, and a 3:1 surrender requirement for exceeding the 0.14 lb/MMBtu backstop daily rate will likely increase generation cost at regulated EGUs, resulting in a potentially significant shift in generation toward small EGUs. The commenter recommends EPA should consider a standardized emission backstop for small EGUs and require all EGUs to surrender allowances for excess emissions above the backstop limit.

Commenter (0291) proposes to address the concern that facilities have not been operating their control equipment at all times is explicitly addressed.

Response:

For the EPA's response to comments on the backstop daily emissions rate provisions, see Section VI.B.7 of the Preamble. In regard to the particular concern that the daily backstop 3-for-1 surrender ratio may provide an insufficient incentive for sources to operate existing controls, EPA notes that the expected allowance price is fully expected to encourage control operation (even more so after applying a 3-to-1 surrender ratio). Moreover, EPA also notes that the complementary dynamic budget and bank recalibration provisions are meant to preserve the rule stringency and corresponding allowance price incentive to operate controls in this final action.

Comments:

Commenter (0373) writes that EPA should eliminate the backstop emissions rate. The commenter writes that the increased allowance costs (or even the unavailability of allowances) could make it virtually impossible to continue operating coal-fired generation without installing SCR and could force the idling of coal-fired generation during peak summer demand periods if they are unable to obtain additional NOx allowances. The commenter states that the higher NOx allowance surrender requirement will penalize coal-fired generation that has SCR in cases when units must operate above the backstop limit due to malfunctions or other problems. For these reasons, the commenter states that the EPA should exclude NOx emissions during startup, shutdown, and malfunction (SSM) periods for determining compliance with the backstop NOx emission limit, if the Agency decides to impose a backstop in the final rule. The commenter relates that SCR controls cannot operate during SSM periods and, as a result, coal-fired units will be unable to comply with the backstop limit during these SSM periods. Furthermore, the commenter states that the final rule should clarify that the increased 3-to-1 allowance surrender requirement applies only to the portion of the NOx emissions that exceeds the backstop limit and not all of the NOx emissions during the day.

Commenter (0547) argues that the proposed enhanced trading program will create substantial compliance uncertainties for affected EGUs and is overly stringent. The commenter states that they are "an overreaction" and will make long-term generation planning more difficult and pose major issues for grid stability and reliability. The commenter requests the following changes to the program:

- Scale back the proposal to only targets those amounts of pollution that contribute significantly to nonattainment in downwind States and eliminate forced generation shifting from the rule.
- Ensure a sufficient number of allowances are available for affected sources to meet peak summer demand and protect grid reliability.
- Eliminate the dynamic budgeting process, or, at a minimum, delay implementation of dynamic budgeting until after 2026.
- Finalize dynamic budgets at least two years prior to the applicable control period. Additionally, the EPA should be required to calculate preliminary budgets and allocations for the additional years beyond the upcoming control periods.
- Consider other representative factors besides heat input when calculating dynamic budgets.
- EPA should have a process in place to appeal the initial allocation or allow sources to obtain additional allowances outside of the trading system for meeting load demand growth.
- Provide an off-ramp or process to address the likely scenario that a lack of allowances affects grid stability and reliability.
- Eliminate the recalibration process for banked allowances from the proposed rule.

- Eliminate the unit-specific backstop daily emissions rates and secondary emissions limitations from the proposed rule.

Alternatively, EPA should clarify exactly how the daily emissions rates will be calculated and require a certain minimum amount of valid operating hours in the 24-hr period before a daily average value can be calculated. The EPA should also consider excluding periods of startup, shutdown, and malfunction from the calculation of the daily emissions rates.

Commenters (0289, 0290, 0323, 0330, 0332, 0336, 0341, 0361) overall assert that the daily limit does not account for or provide a distinction between start up, shut down and malfunction (SSM) operations, when use of a control device is unsafe or inappropriate, and situations when a unit could otherwise be controlled safely and effectively; essentially punishing a unit just because they are starting up/needed to help meet electricity demand. Commenters note as more and more renewables like wind and solar enter the generation mix, there will be more and more cycling of traditional base load plants and more and more start-up days where this will present problems – a problem not considered under this new requirement. Commenter (0290) believes that EPA should exclude NOx emissions for any boiler operating day when SSM events occur consistent with their permit for determining compliance with the backstop NOx emission rate limitation, if the Agency decides to impose such a backstop emission rate limitation in the final rule. At large, commenters (0290, 0336, 0341) propose that the daily backstop limit omit startup and shutdown emissions.

Commenter (0302) disagrees with the application of a new daily limit for all affected units and requests that EPA provide an exemption to the daily 0.14 lb/mmBtu NOx emission limit. The commenter believes there are no environmental benefits gained by imposing NOx emission limitations on well controlled affected units. The commenter explains that its units have existing enforceable limits that are below the proposed daily limit of 0.14 lb/mmBtu, and there is a high likelihood that a unit starting up or shutting down will have a daily emission rate above the proposed value. The commenter explains:

"During startup there are several hours of operation before the exhaust gas temperatures are high enough to initiate SCR operation. Similarly, during shutdown, the unit will reach a low exhaust gas temperature at which point the SCR must be taken out of service prior to the unit being offline. If a new daily limit was in effect, then utilities would be incentivized to only startup shortly after midnight and shutdown shortly before midnight on operating days. This unnecessary operational constraint actually results in the unit operating longer than it would have otherwise and therefore additional overall emissions which are in conflict with the true intent of this regulation. These new operational constraints could also result in operators not making their units available when they would otherwise be needed for grid reliability."

Commenter (0302) writes regarding the proposed daily 0.14 lb/mmBtu NOx emission limit and requests that existing units with SCRs and federally enforceable limits that require their continuous operation not be adversely penalized with a backstop limit any sooner than a unit without an SCR. The commenter writes that the imposition of a backstop limit on these types of units should be in line with the deadline for those units that currently have no SCR installed or have failed to operate their SCRs. The commenter adds that units should not be unfairly penalized at a 3:1 surrender for emissions that exceed the daily rate in the event that the exceedance is due to startup or shutdown. According to the commenter, the intent of this limit is to force SCR operation during the ozone season, not to penalize units that operate their SCRs and especially not those that operate well below the 0.14 lb/mmBtu rate throughout the ozone season.

Commenter (0344) states coalfired units in Indiana are no longer dispatched full-time. In fact, during many months of the ozone season, these units function more like peaker plants. This results in start-up and shut-down emissions having an adverse impact on daily emissions. Therefore, it might be challenging for units to comply with the proposed daily limit.

Commenter (0395) states the daily limit is too stringent for even well-controlled plants to meet consistently. The backstop limit cannot be met consistently when units are running on a lower load or during startup.

Commenter (0394) asserts that EPA lacks authority under the Good Neighbor Provision to establish a backstop daily emission limit at any level for the purpose of requiring EGUs to "improve emissions performance at individual units," and even if EPA were authorized to establish a daily emission rate, the rate it proposes to establish would be too low for most EGUs to achieve on a consistent basis, primarily because of unavoidable startup operations. Commenter briefly discusses Technical Report findings, as support.

Commenters (0397, 0408, 0431, 0500, 0505, 0511, 0533, 0544, 0550, 0553, 0554, 0782) state the backstop limit on EGUs should be eliminated or amended to exclude startups, shutdowns, and downtime events, which many of the commenters point out can extend for more than 24 hours. Commenter (0397) claims that the proposed new daily limit, or backstop, of 0.14 lb/mmBtu on EGU units combusting coal may in fact cause the units to have to run more hours than necessary to ensure that the daily limit is not exceeded, especially if any operating issues arise. Commenter (0431) add that some coalfired EGUs can take up to eight hours to bring the unit up to a temperature that can accommodate the SCR and a daily limit likely would not allow the unit to achieve the rate unless it is set at a level much higher than the rate EPA has proposed, or if units can exclude defined startup and shutdown periods from their calculation of the daily average rate.

Commenter (0511) underscores the point that SCRs are only effective at reducing NOx when flue gas temperatures are above the Minimum Operating Temperature which allows for the injection of ammonia. During startup, shutdown, and low load/derated conditions, SCR equipped units are not able to maintain adequate temperature for SCR operation. Commenter (0511) reports that these conditions can extend for 12 hours or more depending on operational factors. On these days, units could exceed the daily backstop limit due to the inability to operate controls. The commenter worries that EGUs will find themselves in situations where exceeding the backstop rate is unavoidable, with no corresponding recourse; resulting in EGUs possibly being forced to limit/restrict/shutdown operations in high-demand days possibly creating instability and unreliability in the overall power grid to avoid insurmountable penalties. In addition, commenters (0533, 0544) recommend 1) the Daily Backstop Limit should not apply to units with a federally enforceable permit condition that requires continuous operation of an SCR; 2) Set alternative limits for SSM events; 3) subject SSM exceedances to a fixed penalty per ton, rather than a 3-for-1 allowance surrender penalty. Commenter (0553) recommends removing the limit and allowing the stringency of the NOx budgets (which will significantly reduce NOx allowances to EGUs through 2026) and allowance market prices to drive performance of NOx controls through the proven trading program. Commenter (0411) states that the backstop limit of 0.14 lb/mmBtu for coal fired EGUs greater than 100 MW is overly restrictive and unnecessary. According to the commenter, the proposed provision will add difficulty to planning unit operation for coal-fired units in order to stay below the back stop limit potentially bringing units on-line or keeping them on-line unnecessarily simply to lower the daily average emission rate, which could lead to starting units earlier in the day than might otherwise be needed for the grid, or not taking a unit offline at all. Neither of these situations enhances NOx reductions.

Commenter (0414) states the higher NOx allowance surrender requirement will penalize those affected coal fired EGUs operating with SCR systems in those cases when the units must operate above the backstop daily NOx limit due to startups, shutdowns, and malfunctions (SSMs) or other problems encountered in operating their existing SCR systems on any particular day.

Commenter (0528) states that the EPA's assumptions about EGUs' ability to meet the daily backstop rate are flawed in that the EPA's proposed enhancements to the NO_X ozone season Group 3 trading program are too restrictive to allow the market to operate as the EPA portrays. The enhancements will significantly restrict the number of allowances available and hinder the ability of EGUs to trade.

Response:

For the EPA's response to comments on the backstop daily emissions rate provisions, including a response to comments regarding the start-up and shut-down concerns raised by commenters, see Section VI.B.7 of the Preamble. For discussion of related issues, see Preamble Sections VI.B.1.c.1 and VI.B.1.d.

The EPA sees no reason to exempt sources from the requirements in this action due to requirements they may have in a preexisting action related to another statute or standard. In the event that a commenter already has a control operation/short-term rate requirement for an existing control that exceeds the one imposed in this rule, the EPA notes that this eliminates the burden of implementing any additional mitigation measures at the unit and is accounted for in the Engineering Analysis baseline data. In other cases, a source may have a similar requirement to operate a control, but over a more extended time period (e.g., monthly) and so may provide less assurance of good control operation on each day depending on the way the emissions limit was set. Those requirements may be imposed due to less stringent (*e.g.,* prior NAAQS) or different environmental standards (*e.g.*, haze) altogether and do not supplant the requirements necessary to eliminate significant contribution for the 2015 ozone NAAQS in this action.

Comments:

Commenter (0354) states that the proposed daily backstop rate would effectively require that operators of most coal-fired EGUs either install SCR on those EGUs or retire those EGUs, as most units will struggle to meet the daily limit of 0.14 lb/mmBtu with the subsequent penalty being allowances surrender at a ratio of 3:1. Effectively, since this backstop rate would act in addition to the NOx allowance requirements, it would serve as a source-specific NOx emission control requirement and would go beyond the required NOx reductions necessary for attainment. The commenter adds that the backstop limit is unnecessary, as EGUs will already be incentivized to reduce NOx emissions due to the significantly reduced allowance pool in the Proposed FIP.

Commenters (0286, 0372, 0409, 0547) state, in general, that the backstop rate is unachievable, and it does not account unit startup, and it may increase NOx emissions by eliminating low load flexibility. The commenter also states that the daily rate provides no provision for malfunctions, the 2024 and 2027 compliance dates are inequitable to well-controlled units, there is no justification for the rate. The commenter also states daily emission rates are not considered in the FIP's estimated NOx emission reductions for the 2026 attainment case on the downwind monitors and should not be applied to common stack units with dissimilar NOx controls until 2027. At least one commenter (0286) does not believe that the EPA has the authority to impose such limits, but if it were, the limit as proposed would be unworkable given the short averaging time.

Commenter (0332) states EPA is correct in not applying it to natural gas-based EGUs—given the relatively lower NOx emissions rates from these units. The EPA should consider revising the penalty from a 3-to-1 surrender downwards to 2-to-1 or lower for units that have been operating their installed controls historically and thus may not need the additional "incentive" of a more stringent surrender requirement. EPA should consider suspending the allowance surrender requirement for units that have permitted emissions rates or other permit terms that should supersede the EPA's Backstop Rate and would provide an enforceable guarantee those units were operating controls.

Commenter (0340) states the EPA is restricting economic development and potential job growth in Kentucky. Facilities that would be subject to the emissions controls and daily backstop rates proposed in this rule would be unlikely to consider Kentucky a viable location, instead potentially choosing to locate in a state that is not subject to the proposed rule. This proposed rule punishes manufacturing states like Kentucky. Low-cost electricity is an incentive for industries looking to expand and has provided Kentucky with over $11 billion in investments and new jobs, including two new electric vehicle battery plants. In a time when more emphasis is being placed on American independence from reliance on other countries for goods, this rule inhibits the ability of manufacturing states to be competitive in attracting new businesses.

Commenter (0323) states the proposed backstop daily emission rate penalties are inappropriate because NOx budgets should be set based on achievable rates for controls without penalties for emissions occurring during high demand days when the choice is to maintain system reliability by running units with controls or shut down the units because of the backstop daily rate penalties.

Commenters (0512, 0519) state rather than resolving imagined widespread failure to operate existing control equipment, EPA's proposed daily limit will interfere with unit operations by limiting needed operational flexibility and effectively increasing the stringency of EPA's seasonal limits. Commenter (0519) acknowledges that lower utilization of SCR may be desirable to combat "engineering challenges of operating controls at low utilization, such as fouling and minimum operating temperature constraints." Instead, by eliminating operational flexibility, commenter (0519) warns that EPA creates a significant risk of overcontrol, forcing covered units to either limit operations or further reduce emissions during cert.am operating periods in order to comply with the daily limit.

Commenters (0519, 0541, 0551,) states that the daily backstop limit is not justified to address significant contribution and will result in overcontrol. Commenter (0541) observes that under EPA's proposal, even if a state has achieved reductions in the amounts identified by EPA as the state's significant contribution, a source would still be penalized if it operated over the backstop emission rate, and in such a scenario, EPA's backstop emission rate is divorced from any air quality obligation under Section 110(a)(2)(D). Commenter (0541) asserts that while EPA believes the backstop rate is necessary to ensure sources continuously operate installed SCRs, this justification is insufficient, as it is not the stand-alone operation of controls, but the "amount" of NOx emissions eliminated, that is relevant. In any event, the simple inclusion of a backstop rate fails to account for the nature of SCR operation – *e.g.*, unable to operate under SSM events. The commenter further asserts that if a backstop is finalized, it should not be applied to units that have not installed SCRs, regardless of how EPA modeled that source during budget setting, and a mass-based alternative may be more appropriate. Commenter (0551) suggests that policy goals (*e.g.*, to prevent individual sources from idling controls), however meritorious in their own right, do not actually address the issue of significant contribution. Even if they did, the commenter explains that the limited record information is not sufficient to establish that the backstop emission limit would have any effect on peak days or overburdened communities. Commenter (0551) states the EPA might be able to revise the daily backstop emission limit requirement to address the over-control problem the proposed rule poses by sunsetting daily limits for units in states that reduce overall emissions to resolve their significant contributions.

Commenter (0359) states considering that EGUs are now less than 10% of the total ozone-season NOx inventory in West Virginia, the commenter disagrees with the EPA proposal to introduce additional features to the allowance-based trading program approach for EGUs, including, for example, dynamic adjustments of the emissions budgets over time, and backstop daily emissions rate limits for most coal-fired units with a 3:1 allowance surrender ratio if exceeded More specifically, commenter (0359) states that the proposed daily emissions rate limit of 0.14 lb/MMBtu in 2024 for coal-fired units with existing SCRs in 2027 for units currently without SCRs does not allow for operational flexibility throughout the ozone season. Commenter notes that 90% of the coal-fired EGU generating capacity NOx emissions in West Virginia are already reduced with both combustion and post-combustion controls, including low-NOx burners and SCR, with total control efficiencies of greater than 90 percent. The remaining units also have combustion and post-combustion controls, including low-NOx burners and/or over-fired air burners, and SNCR.

Response:

See Preamble Section VI.D.7 for the EPA's response to comments on the backstop daily NO_X emissions rate. See also Preamble Section V.D.4 for EPA's overcontrol assessment. The daily backstop rate is a step 4 implementation measure to ensure that significant contribution as determined at Step 3 is and remains prohibited. It does not alter the stringency of the rule.

Comments:

Commenter (0782) writes that requiring direct controls on individual units removes the flexibility of a trading program. The commenter explains, “Requiring a daily backstop emissions rate in addition to the requirements of the trading program has never been done in a prior CSAPR rulemaking. The EPA contradicts itself by emphasizing the importance of implementing a flexible trading program rather than making unit-specific assumptions, but then proposes to make unit-specific assumptions for coal units with existing SCR at an assumed operational rate. By continuously applying a unit-specific backstop daily emissions rate, EPA is removing the very economic incentive to outperform that rate and the very flexibility that a trading program is intended to create. The EPA claims that the backstop rate is designed to "ensure that all individual SCR controls have strong incentives to continuously operate and optimize their controls," but this is not an incentive - it is a direct regulation that requires a 3- for-l allowance surrender penalty for exceedance of the rate.”

Commenter (0300) states backstop emission rate effectively requires all coal fired EGUs to install controls in order to operate, which eliminates the flexibility of a trading program.

Commenter (0396) states the limit eliminates the potential benefits of emission allowance trading, which depends on the ability of some sources to overcontrol and free up allowances for those that find it less cost-effective to install new controls. It is also too low to be met. The commenter also states both an extension of the back stop limit and adjustments to the trading program are needed for units that commit to retire by the end of 2028.

Commenters (0500, 0554) state by requiring a daily rate that cannot be met without installing and continuously operating an SCR, EPA is unknowingly turning a trading program into a technology forcing program similar to the New Source Performance Standards (“NSPS”). This is not consistent with "good neighbor" obligations under the CAA. The commenter (0500) also states penetration of renewables will drive a decrease in total emissions, but an increase in some EGU rates as units cycle more and aligning compliance with provisions of the proposal with compliance dates associated with other rules would provide for a smoother fleet transition.

Commenter (0521) states the proposed daily assurance emission rate limit of 0.14 lb/mmBtu has no part in a cap-and-trade program and would, in essence, allow EPA to establish new permitting limitations without reason or for any reason. Commenter suggests that if this provision was introduced as part of the original CSAPR, affected source operator/operators would have rejected this attempt to expand the EPA authority under this section of the CAA. Additionally, according to the commenter, it may have precluded affected units from installing control equipment that has contributed to a steady decline in NOx emissions for the past decade or more. Commenter (0521) highlights the fact that EPA’s own technical documentation does not support the proposed daily assurance emission rate as to fixing the nonattainment/maintenance interference at the downwind receptors.

Commenter (0528) express concerns that the proposed backstop rate, coupled with EPA's assumptions regarding the emission rate achievable with SCR, effectively requires most large EGUs that do not currently have SCRs to either install SCRs (regardless of actual costs) or retire. The commenter explains that because EPA is also proposing a dynamic budget and changes to allowance allocations, there is likely to be little, if any, flexibility in the Proposed FIP to allow such units to comply with the Proposed FIP through the purchase of allowances. Commenter asserts that units are unlikely to incur the significant costs to install new SCRs when many are slated to retire in only a few years and will instead retire early. Arguably, such a requirement – install SCR or retire – is at odds with the purpose of a trading program.

Response:

See Preamble Section VI.D.7 for the EPA's response to comments on the backstop daily NO_X emissions rate. With respect specifically to the comments asserting that the backstop rate provisions remove the incentive to outperform the backstop rate, the EPA disagrees because the comments are unsupported and illogical. Due to EPA maintaining an allowance trading program, sources will still have the incentive to outperform the daily backstop rate in order to create as many surplus allowances as possible for sale or to reduce the number of allowances that must be acquired for compliance. The backstop rate will not reduce incentives for a source to improve its emissions performance and in fact will strengthen those incentives in instances where a source expects that reducing its emissions by one ton could reduce its allowance surrender requirements by three allowances rather than one allowance.

Comments:

Commenter (0290) requests that the daily backstop NOx emission rate of 0.14 lb/mmBtu not apply to coal-fired steam units that have formally initiated retirement or have initiated the process of repowering with natural gas by the end of 2026.

Commenter (0330) states EGUs should not be penalized for exceedances of a backstop limit due to limited operating hours. It makes no sense to penalize minimal NOx mass emissions due to the unavoidable technological limitations of the SCR. Large coal-fired units complying with the daily backstop emission rate could be emitting several tons of NOx per day with no concern under the proposed rule, while other units with minimal NOx mass emissions could be subject to the backstop penalty due to limited hours of operation and/or not feasibly being able to engage the controls for the reasons describe above. Commenters (0330, 0524) suggests a 30-boiler-operating day average, which would be a more reasonable approach that allows for minimal periods of operational flexibility. The commenter (0524) supports the Agency's proposal of deferring the application of the backstop for large coal EGUs that are committed to retiring by the end of 2028.

Commenters (0499, 0533) state the limit is unnecessary because the reductions proposed for the state budgets ensure that units will operate their SCRs as they will lack necessary allowances to compensate for not running their SCRs. The EPA has failed to take into account that some EGUs are subject to air quality regulations, permit limits and/or consent decrees that obligate them to operate their SCRs. The daily backstop emission rate also effectively requires the installation of expensive controls on most large coal fired EGUs that are not currently equipped with SCR technology. Utilities would be unlikely to incur the significant costs to install new SCRs at EGUs that are slated to retire within a few years after 2026 and instead will likely seek to manage operations and allowance allocations with the units' existing controls until their retirement dates or retire early. The commenters urge EPA to instead use the rate that has been demonstrated to be achievable on approximately 99 percent of days, as opposed to 95 percent of days. The commenters also state that the use of a daily backstop emission rate does not account for day-to-day variability in operations and penalizes EGUs that experience emissions monitoring issues. The commenters support extending the enforced retirement year of 2028 but suggests 2032.

Commenter (0554) states the backstop daily limit drives universal installation of SCR by 2026. this deadline is impossible. The commenter supports extending the enforced retirement year of 2028.

Commenter (0533) advocates more flexibility; suggesting: 1) EGUs that must operate their SCRs should not be subject to the limit; 2) Units that make an enforceable commitment to retire by the end of 2030 should not be subject to the daily backstop limit; 3) Low-capacity factor EGUs should not be subject to the daily backstop limit; 4) Units that elect to comply with an emission averaging plan should not be subject to the daily backstop limit; and 5) Common stack units should not have to separately meet the daily backstop limit.

Commenters (0431, 0550) state, alternatively EPA should grant an exemption to EGUs that have near-term federally enforceable retirement or cease to use coal ("CTUC") dates (by 2030 or earlier) to be exempted from the backstop daily emission limit.

Commenter (0348) briefly discusses court finding in the case, State of Wisconsin v. EPA and contends EPA should further analyze whether the environmental benefits of the proposed FIP justified the costs imposed by the FIP. The commenter states that the proposed rule does not explore whether the emissions controls in question would endanger reliability, and the attendant costs associated thereof, or cause the closure of generating capacity. Additionally, the commenter notes that the proposed rule does not currently contemplate a step for the Regional Transmission Organization ("RTO"), Independent System Operators, or FERC to study reliability impacts. The commenter states that given the exceptional complexity of grid reliability concerns, it is noteworthy that the proposed rule does not provide a more rigorous exploration of the impact of the rule on grid reliability and the resultant costs from an environmental justice and monetary perspective. The commenter also notes that EPA's control cost analysis uses an EGU inventory that is divergent from the inventory of EGUs that exist in the 25 states subject to the proposed transport rule. The commenter provides that all of these issues do not lead to an accurate calculations of costs and this issue needs to be re-examined.

The commenter also believes that EPA's proposed backstop daily emissions rate penalties, 87 Fed. Reg. at 20,121, are inappropriate because NO_X budgets should be set based on achievable rates for controls without penalties for emissions occurring during high demand days when the choice is to maintain system reliability by running units with controls or shut down the units because of the backstop daily rate penalties. The commenter notes that EPA has also acknowledged that there is "very little difference" between "NO_X rates for EGUs for hours with high energy demand" and "seasonal average NO_X rates." 83 Fed. Reg. at 50,466. Moreover, the commenter provides that Maryland Court recognized that "there may be valid operational reasons not to operate catalytic controls on particular days, '*e.g.*, to avoid damaging or plugging of the [control] or taking a forced outage where a breakdown leaves the unit unavailable to produce power.' As a result, that a source ends up emitting above 0.20 lb/mmBtu on a particular day is not necessarily evidence of a failure to optimize."

Furthermore, the commenter provides that EPA's operational restriction by imposing a daily limit with a substantial allowance penalty will force decisions that are contrary to the effective management of generation and emissions. The commenter contends that situations that may result in exceeding EPA's proposed daily limit include necessary startup or shutdown of units based on system demand, operation of units at minimum load conditions to meet grid requirements, and even short-term operation of a unit after malfunction of NO_X controls. The commenter states that on high demand days, EGU operators and RTOs will face the choice to maintain system reliability by running units with limited NO_X control or shut down the units because of the backstop daily rate penalties.

Response:

See Preamble Section VI.B.7 for the EPA's response to comments on the backstop daily NO_X emissions rate. See also Preamble Section VI.B.1.d for EPA's response to comments regarding the daily backstop rate implementation schedule. The EPA notes that with the changes made in the final rule, the daily backstop rate would not apply to non-retrofitted sources retiring by 2030 (unless the source nevertheless were to retrofit SCR at least one year prior to retirement).

Comments:

Commenter (0302) writes that if the daily rate of 0.14 lb/mmBtu is imposed, NOx emissions data should not be bias adjusted and should not include any substituted data due to emission monitoring issues. The commenter states that substituted data is important for a mass-based emissions program but is inappropriate to determine compliance with an emission rate limitation. According to the commenter, the data substitution protocols already require units to surrender more NOx allowances in a mass-based program than they likely actually emitted. The commenter states that if this situation resulted in an exceedance of the new daily rate limit of 0.14 lb/mmBTU, then the unit would be even further penalized with the three to one allowance surrender imposed. The commenter further states that NOx emissions data that is diluent capped (*i.e.*, startup hours where CO_2 is less than 5%) should also be excluded.

Commenter (0533) urges EPA to use the rate that has been demonstrated to be achievable on approximately 99 percent of days, as opposed to 95 percent of days. Given there are 157 days in the ozone season, EPA should not set the rate at a level that it has determined may be exceeded on more than seven of those days. The commenter also states that the Part 75 requirements for adjustments to the NOx data should not be used to demonstrate compliance with the daily backstop rate because this conservative data substitution protocols already require EGUs to surrender more NOx allowances in a mass-based program than they are likely to have actually emitted. The commenter also states the backstop rate should not apply to units that operate for a limited number of hours and EPA should allow EGUs to meet a mass-based daily option.

Response:

See Preamble Section VI.B.7 for the EPA's response to comments on the backstop daily NO_X emission rate. See also Preamble Section VI.B.1.d and VI.B.1.c for additional discussion of EPA treatment of daily backstop rates in this final rule. With respect to suggestions that the emissions data used to measure exceedances of the backstop daily emissions rate should exclude certain data and should not be bias-adjusted, the EPA disagrees. The historical data analyzed by the EPA to establish the level of the backstop rate included historical data as reported by sources, including bias adjustments and data reported for hours with substitute data and hours where a diluent cap value is used, so it is consistent to use analogous data for evaluation of exceedances. With respect to emissions data during start-up hours, the EPA notes that the addition in the final rule of a 50-ton threshold before the 3-for-1 surrender ratio applies is expected to cover emissions during start-up hours, as discussed in Preamble Section VI.B.7. With respect specifically to inclusion of substitute data, the EPA finds that the purposes of the substitute data provisions in 40 CFR part 75 – to ensure that emissions are not under-reported and to provide incentives for good maintenance of monitoring systems – are just as appropriate for determining allowances that must be surrendered under the backstop rate provisions as for determining other allowance surrender amounts.

Comments:

The commenter (0328) also states the application of the backstop rate will cause an economic disparity that will allow higher emitting NOx units to run at an economic advantage for two years. This could cause an increase in NOx precursor emissions and the transport of ozone within the two-year timeframe due to generation leakage toward higher emitting units. The economics, due to the backstop, may displace cleaner coal generation in favor of these higher emitting small EGUs that can now operate at a lower cost. The "SCR coal only backstop" could increase NOx emissions on high ozone days due to generation leakage to small EGUs, which are not currently addressed in the Proposed Transport Rule. The commenter recommends that the EPA should apply the backstop or another similar standard to these units and require a 3:1 surrender for excess emissions consistent with the proposed backstop for coal units.

Commenter (0530) encourages EPA to consider whether daily backstop compliance must be on a unit-by-unit basis or if requested, the limit could be averaged across a facility, or perhaps more broadly across a fleet. Averaging could also occur among units owned by different companies; however, to maintain the integrity of this provision, averaging should occur among units that are in the same ozone attainment region. Under certain scenarios well controlled units can provide a compliance margin for a particular unit may that not be in compliance with the daily backstop rate (*i.e.*, unit in startup).

Commenter (0782) states EPA should account for generation shifting to renewable generation units in its backstop daily emissions rate calculation and exclude coal-fired units with annual capacity factors below 10% from applicability of the backstop daily emissions rate. The commenter suggests that such an exclusion would be analogous to provisions in other EPA regulations that include alternative limits for stationary spark ignition internal combustion engines during "emergency" situations. The commenter also states that EPA should lower or eliminate the proposed allowance surrender penalty for units that are required to operate their controls by permit conditions or that have historically operated their controls.

Commenter (0332) states EPA should consider developing an abbreviated SIP option that would allow multi-unit owners to average their emissions rates and operating times in order to show that when, taken together, multiple units meet the backstop rate without having a specific daily requirement per unit. Commenter provides the following example for three units of varying size – A at 500MW, B at 400MW, and C at 300MW of nameplate capacity – which operate at different capacity factors on an individual day during ozone season. The commenter explains that there are likely scenarios whereby two units – A and B – operate at high-capacity factors and through their efficient operations and the utilization of installed controls easily comply with the backstop rate, but the operations of those two units might not be sufficient to meet energy needs, requiring the smaller unit C to operate for a limited amount of time. However, given the limited time operation of Unit C in this scenario, the commenter states that Unit C's emission rate could significantly rise beyond the level specified by the backstop rate, but would not actually emit anywhere near the same number of tons of NOx as Units A or B. As a result, Unit C, despite emitting significantly less NOx, would be subject to a significant allowance surrender penalty under this scenario for essentially no environmental gain.

Response:

See Preamble Section VI.B.7 for the EPA's response to comments on the backstop daily NO_X emissions rate. With respect specifically to comments asserting that the backstop emissions rate provisions would cause generation to shift to units with higher emissions rates, the EPA disagrees. As discussed in Preamble Section V.B, the cost to optimize a partially operating control (this includes most of the units identified with SCR optimization potential) is estimated to be $900 per ton. The EPA does not agree that this cost would incentivize higher emitting sources to operate more than those lower emitting sources with a daily backstop rate. First, the majority of dispatchable sources are lower emitting than a coal unit not operating its SCR, so the shift would more likely be to a lower emitting unit. Second, even for higher emitting sources without a daily backstop rate, those sources are subject to the program and have an allowance holding requirement. Emitting more at these units would require the procurement of additional allowances. Optimizing partially operating SCR was determined to be the lowest cost mitigation measure of those assessed for EGUs at Step 3. Generation shifting would generally occurs from sources with higher compliance cost to those with a lower compliance cost, yet the comment implies the reverse. Because the backstop rate is premised on one of the lowest cost mitigation measures available, it is not likely that this generation, and low cost compliance opportunity, would be replaced by other generation with higher mitigation cost. The EPA also disagrees with suggestions to implement the backstop rate provisions through averaging across units instead of on a unit-specific basis. The overall trading program approach already allows broad averaging of emissions reduction efforts across units. As explained in Preamble Sections VI.B.1 and VI.B.7, the backstop daily rate provisions are designed to supplement the rule's other provisions with requirements incentivizing better emissions performance from individual units. Introducing averaging would undercut the purpose of the backstop rate provisions.

5.2.1.5 Secondary Emissions Limitation

Comments:

Commenter (0510) strongly supports the inclusion of secondary emission limits at the time of assurance exceedance and the impact they will have in making a more effective trading program that holds upwind states accountable for their contributing emissions – *e.g.*, preventing states from purchasing significant quantities of cheap banked allowances to cover penalties from anticipated exceedances of the assurance level

Commenter (0373) states that EPA should eliminate the secondary NOx emissions limit. The commenter explains that it would "impose a unit-specific requirement that could significantly reduce the flexibility of the emissions trading program by prohibiting each coal-fired unit from exceeding its benchmark seasonal average NOx emissions rate." The commenter opposes this limit because "it layers on top of the emissions trading program an inflexible requirement that is unnecessary for remedying ozone nonattainment problems in downwind states." The commenter adds that it is redundant because the transport rule assurance provisions are already intended to limit the degree to which a state could rely on purchased allowances from other states as a substitute for its in-state emission reductions. The commenter explains, "the current CSAPR assurance provisions already place significant constraints on the use of surplus NOx allowances in cases where a state is overly reliant on out-of-state allowances for meeting its in-state requirements. In such cases, an additional two NOx allowances (for a total of three allowances) must be surrendered for each ton of NOx emissions above a state's assurance levels. The EPA has already set each state's assurance level based on the NOx emission reductions that are sufficient to remedy its contribution to downwind ozone nonattainment problems in other states. As a result, the CSAPR assurance provisions already establish a regulatory requirement that limits the degree to which a state could rely on purchased allowances from other states."

Commenter (0341) states that the EPA's secondary emission limit based on the state's variability limit is unnecessary and based on something that cannot be monitored or controlled, since a facility would not know whether a unit exceeded the limit until months after the operation occurred. The commenter describes this as an "outside the fence control" with no avenue for units to self-correct over the course of an ozone season. The commenter believes that this unfairly punishes units that may have contributed to the exceedances and limits an EGU from utilizing NOx allocations. The commenter states that EPA has not demonstrated the need for this additional emission limitation, nor has it provided documentation of an exceedance of a state's assurance level resulting in failure to address significant contributions to downwind air pollution. The commenter argues that the secondary emission limit does not directly drive local attainment in downwind states during the specific control period, is unjustified, and should be removed from the final rule.

Commenters (0282, 0272) propose that the secondary emissions limitation should be applied during the control period following the year when the assurance level exceedance occurred. The commenters express concern that a unit or company may know its compliance status during the ozone season, but the total state emissions are usually not known until well after the end of the ozone season. At that point, it is too late for a unit to change or limit its operation to avoid exceeding its assurance level. Furthermore, commenters state that for dual-fueled units, prior years' operations may be based primarily on a lower-emitting fuel, but during the current ozone season, the unit may require more use of the higher-emitting fuel, which creates problems when imposing an emissions limit for the current ozone season. The commenter (0272) suggests calculating the secondary emissions limitation based on the higher emission rate of 0.1 pounds/MMBtu or 1.25 times the lowest seasonal average NOx emission rate in a previous control period.

Commenter (0395) states that the proposed secondary limit for EGUs is a radical departure from the cost-effectiveness plus trading approach EPA has previously championed and opposes the adoption of this program element. The commenter notes that a violation will only occur if the state as a whole exceeds its assurance limitation, but since individual companies have no way of knowing whether the state as a whole will exceed the budget until the ozone season is over; EGUs will almost certainly treat the limit as enforceable against their unit as they would a command-and- control limit. The commenter adds that there is no exception in the proposed rule for circumstances where an exceedance of the allowances is unforeseeable, which the commenter characterizes as a significant increase in penalty compared to providing extra allowances. The commenter argues that this could negatively affect providers who are increasing generation in response to increased demand. The commenter writes that the proposed rule does not directly address the problem of NOx nonattainment at downwind monitors since the violation becomes active only once the state passes its assurance limit toward the end of ozone season.

Commenter (0554) argues that it will be extremely difficult for EGUs to comply with the proposed secondary limit:

"Due to the sheer complexity of it, sources are unlikely to be aware of whether they are approaching the limit before the end of the control period, which will be too late to avoid an exceedance. To determine whether an exceedance may occur, EGUs would need to first determine the variability limit for their state, but that determination cannot be made until the end of the control period, since it may depend on whether the total heat input across the state at all affected EGUs exceeded budgeting assumptions by more than 21 percent. Even if the variability limit could be determined with certainty prior to the end of the control period, determining whether a state will exceed that variability limit prior to the end of the period will also be difficult. And even if a state-wide exceedance could be predicted, an EGU would need to predict whether its own emissions will exceed its allowances by more than the applicable variability limit, determine its historical rate to identify the benchmark rate, predict total emissions for the entire control period, and compare the resulting calculation to the 50-ton limit. With all of these moving parts, determining compliance prior to the end of the control period will be impossible."

Commenter (0554) opposes the proposed secondary emission limitation on the grounds that it will "limit flexibility and impede (if not preclude) market trading without furthering the purpose of its proposal, which is to eliminate significant contributions to downwind receptors." Commenter adds that "Since any exceedances of the new limit only trigger enforcement and penalties, not increased allowance holding requirements, the limit seems designed to discourage any exceedances, not remedy them. But the requirements of the limit are so complicated that the risk of a violation will not be known until the control period is already over. Source operators will not be able to alter their behavior without some notice of a need to do so, and the structure of the secondary limit will not provide any notice at all. Source owners are likely to find themselves unexpectedly facing penalties at the end of a control period once the required calculation can finally be run. Because the post-hoc payment of penalties will not affect actual emissions, it is not reasonably related to the purpose of the proposal and should be eliminated."

Commenter (0554) writes that the proposed secondary assurance limit is unnecessary as a result of the effectiveness of the current provision, pointing to North Carolina v. EPA, in which the DC. Circuit "rejected CAIR because it failed to ensure that emission reductions needed to eliminate a particular state's significant contribution would come from within that state's jurisdiction." The commenter states that the assurance provisions found in the current CSAPR rules "draw an appropriate balance between lawfully responding to the D.C. Circuit… and maintaining the flexibility to accommodate year-over-year differences in actual EGU operations and emissions." The commenter criticizes EPA's justification for the proposed secondary limit:

"Despite lauding the success achieved with its prior assurance provisions (from both a legal and practical perspective), EPA suddenly and inconsistently concludes "the assurance provisions' very good historical compliance record is not good enough." EPA's only basis for this conclusion is a reference to isolated examples from two states, Mississippi and Missouri. With regard to Mississippi, EPA recognizes that the historical exceedance of variability limits that triggered the assurance provisions was unintentional; for Missouri, EPA ascribes more deliberate and intentional motives. But even in these cases, the assurance provisions worked as designed—the EGUs involved were required to offset the exceedances of the variability limits by procuring allowances on a 3-to-1 basis, which ensured that overall emissions were actually lower than EPA previously determined necessary to accomplish the ultimate goals of the program."

Commenter (0408) states the secondary limit is not something that can be monitored or controlled. A facility would not know if a unit exceeded this limit until months after the operation occurred; therefore, there is no way for units to self-correct over the course of an ozone season. The EPA has not demonstrated the need for this additional emissions limitation nor provided documentation that an exceedance of a state's assurance level has actually resulted in failure to address significant contribution to downwind air pollution.

Commenters (0499, 0533) generally support EPA's proposed change to the state variability limits, which would set a 21 percent variability limit as the floor starting in 2025 and would allow for higher variability limits depending on the percentage 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. The commenters, however, opposes the secondary limitations, with potential enforcement penalties, arguing that is a disproportionate response to this limited occurrence, and suggest EPA should instead identify units that contribute to an exceedance of a state's assurance level and take appropriate action on a case-by-case basis (as opposed to a blanket requirement). The commenters also note the secondary limit may penalize units that are dispatched to meet reliability needs, and it would be imposed for the same control period where the exceedance occurred. The commenters urge EPA to assess historic generation data for zero-emitting sources and ensure that EPA's proposed requirements for sources exceeding the assurance level does not penalize sources for meeting demand if/when zero-emitting sources are unavailable. Additionally, the commenters state that EPA is proposing that the secondary emissions limit would be imposed for the same control period where the exceedance occurred. Commenters contend that using this approach, units will have no way of knowing that a state's variability limits has been exceeded until after the fact. – *i.e.*, there is no way for units to self-correct over the course of an ozone season. Commenters (0499, 0533) believe that such an approach unfairly punishes units that unintentionally contribute to an exceedance.

Commenter (0551) states that unlike the other enhancements, "the principal purpose" of the assurance level backstop "is to strengthen the assurance provisions, which apply on a statewide, seasonal basis," and any unit-specific incentive of the assurance level backstop to maintain unit emissions performance at levels consistent with the operation of specific controls would be secondary. For this reason, the commenter believes that the assurance level backstop may result only in over-control that is incidental to EPA's efforts to ensure that each state eliminates its significant contribution to downwind nonattainment or maintenance issues. The commenter maintains that EPA should further evaluate this enhancement to determine if it will effectively address potential exceedances of the assurance levels and to show that its primary impact will not be the operation of controls despite overall reductions in NOx emissions that already satisfy upwind states' good neighbor obligations. The commenter further contends that the overall effect of the four enhancements, including the proposed assurance level backstop, is to ensure that controls are operated even when those controls are not needed to eliminate significant contribution, which is inconsistent with the good neighbor provision and the court rulings addressing EPA's interstate transport authority (*i.e.,* D.C. Circuit's decision in North Carolina). Accordingly, the commenter recommends that the EPA reevaluate the need for the four enhancements and eliminate them unless they are demonstrably necessary to address significant contribution. As an alternative, the commenter suggests that EPA might also attempt to modify the enhancements to eliminate the aspects of them that will cause over-control provided the Agency can develop adequate record evidence that over-control will not result from their implementation.

Commenter (0551) states the proposed rule would authorize administrative or judicial action, penalties, and other forms of relief under the CAA's enforcement authorities for any emissions by a unit that exceed its secondary emissions limitation, as calculated under the assurance backstop provision; however, the rule does not specify how any of the penalties might be calculated or what form enforcement might take. The commenter mentions EPA's rational for adding the penalties; pointing out that even though EPA acknowledges that the two instances use to support impressions were "not prohibited by the current regulatory requirements, the Agency still argues that potentially onerous but undefined penalties are necessary to prevent the recurrence, of what the commenter maintains is already a very rare incident. Commenter concludes that proposed enhancement provisions are a serious departure from EPA precedent under section 110(a)(2)(D)(I)(i) and would impose significant new burdens on states and regulated parties, and should therefore, be eliminated or revised.

Commenters (0396, 0521, 0550) ask the EPA not to finalize the “secondary emission limitation” that EPA has proposed as an additional “assurance” against unit owners relying primarily on allowance purchases instead of actual emission reductions. Commenter (0396) states that the EPA’s justification for the limit is that the “assurance” penalty imposed under CSAPR for sources that buy allowances instead of reducing emissions, although proven effective, is just “not good enough.” According to the commenter, rather than being evidence of a problem that needs to be addressed, the EPA’s examples show that such occurrences are not only rare, but when they occur, the program works well to maintain environmental protections. In sum, EPA fails to explain why a “secondary emission limitation” is necessary to address these limited circumstances. Commenters (0396, 0521, 0550) add even if it were needed, the “secondary emission limit” is unnecessarily complicated because it depends on a variety of variables that cannot be predicted in advance, making it impossible for regulated sources to know whether it will apply until a violation has already occurred. In brief, the limit applies if the state exceeds its assurance level (which itself may depend on changes in heat input), and the unit contributes to that exceedance of the assurance level, and the unit would have emitted at least 50 fewer tons of NOx than if it had emitted at its benchmark emission rate. According to the commenters, this complex formula is difficult to understand and even more difficult to apply.

Commenter (0521) argues that a secondary emission limit for individual units removes any operational flexibility and does not take into account historical constraints or control equipment degradation that can occur between maintenance cycles. The commenter states that the benchmark limit, as states’ budgeted allocations are slashed, becomes the artificial limit for an individual unit’s compliance mechanism.

Commenters (0396, 0550) state that since the secondary emission limit will not accomplish the purposes for which it is designed, it is arbitrary and should be abandoned. The commenters note that if each of the myriad conditions of the secondary emission limitation is met, the source, with no advance notice or ability to adjust, could find itself in violation. They argue that while the only possible value of the limit would be to discourage certain behavior, the limit is designed in such a way that it cannot discourage anything because no one will know if it applies to otherwise lawful activities until well after the fact.

Commenter (0530) is concerned that the imposition of this limit within the same ozone season is problematic. A unit or company may know its compliance status during the ozone season; however, the total state emissions are usually not known until well after the end of the ozone season. At that point, it is too late for a unit to change or limit its operation to avoid exceeding its assurance level. Another concern with this provision pertains to dual fueled units. The secondary emissions limitation will be calculated based on the higher emission rate of 0.1 lb/MMBtu or 1.25 times the lowest seasonal average NO_X emission rate in a previous control period. For dual fuels, past operation may be based primarily on a lower emitting fuel, but a current ozone season may require significant operation on the higher emitting fuel. Therefore, imposition of an emissions limit based on a lower emitting fuel after the unit has already combusted the higher fuel would present compliance challenges. CEG recommends that any secondary emissions limitation be applied to the control period following the year when the exceedance occurred. At that point, the unit owner will know what the emissions cap is and can adjust unit operation accordingly. T

Commenter (0546) asks that the EPA modify the proposed secondary emission limit for sources that contribute to an exceedance of the state's assurance level such that the secondary limit would not apply to such a source if the primary cause of the assurance provision exceedance was an unforeseeable circumstance, such as additional dispatch due to reduced availability of generation from low-or zero-emitting generation resources in the state or region, or damage to the electrical transmission or distribution system which required operation of a higher-emitting unit in order to meet local electrical demand.

Commenter (0291) writes that there is a high possibility of unintended consequences due to the complexity of the proposal. According to the commenter, there are compliance issues, explaining that the limit will apply at a unit level if the State as whole has exceeded its assurance level and then if the Designated Representative has exceeded the assurance level. The commenter states that the problem is that a Designated Representative only knows the compliance status of his affected units and the potential for the State to exceed the assurance level is not known until well after the end of the ozone season. According to the commenter, it is too late at that point for a unit to change or limit its operation to avoid exceeding its assurance level. That commenter adds that the episodic cap-and-trade proposal will eliminate banked allowances, and adjusting the pool of allowances available for compliance during the compliance period will add uncertainty and complicate the process.

Commenter (0326) states the proposed restrictions are punitive. First, EPA could subject all units within a state to the supplemental limit based on the behavior of one or two units within the state. Second, the commenter reviewed the emissions and allowance allocations for the Group 1 and Group 2 CSAPR trading programs (Attachment A) and found only three states (Arkansas, Mississippi, and Missouri) exceeded their assurance levels between 2018 and 2021. However, EPA provides no evidence that these facilities, which operated in accordance with CSAPR's assurance provisions, contributed to an exceedance at a downwind monitor.

Commenter (0505) claims that EPA's cost analysis for the secondary emissions limit is inadequate and does not address the potential loss of generation capacity nor potential impacts on consumers. To illustrate, the commenter states that in Texas, only EGUs have historically been subject to CSAPR and 57 individual EGUs with emissions rates above the EPA's proposed limits have had well over 25% variation in emissions rates between different years. Limiting emissions to 125% of the lowest year's emissions plus 50 tons could, according to the commenter, greatly reduce the generation capacity of some EGUs, which would adversely impact the future generation capacity and electricity consumers in Texas.

Response:

For the EPA's response to comments on the secondary emissions limitation, see Section VI.B.8 of the Preamble.

5.2.1.6 Set-asides and Unit-Level Allocation Procedures

Comments:

Commenters (0499, 0533) urge the EPA to revise the new unit set-asides to account for units that are offline due to outages or that are being held in reserve but that may not operate for two consecutive ozone seasons. Under EPA's proposed dynamic budget approach, such idled units would effectively be treated as retired and not be factored into state budgets for future years. Nonetheless, such units may be returned to service if needed to provide capacity. If such units did return to service in a future year, the EPA's proposed, limited new-unit set asides may not have sufficient allowances to cover those units. Furthermore, eliminating idled units from the state budget could result in units operating primarily to maintain the state budget and prevent reliance on new unit set asides. For this reason, EPA should distinguish idled units from retired units and retain idled units in the calculation for setting the state budget. The EPA should also expand the new unit set-asides for that state by a corresponding amount. This additional allocation should then be retained in the new unit set-aside until such time as the unit is permanently retired.

Commenter (0355) states EPA's proposed dynamic budgeting approach would serve to significantly limit potential sources of surplus NOx emission allowances in 2026 and beyond. It also risks eliminating consideration of suspended or idled units that have not yet been retired. The commenter explains that, when establishing annual state NOx budgets, EPA proposes to eliminate consideration of retired, idled, or suspended units two years following the last ozone season in which the unit operates. Such units, if re-activated and operated in a subsequent ozone season, would be able to access a limited number of allowances via the EPA's new unit set aside, but likely would not be able to obtain as many allowances as were allocated to the unit prior to being idled or suspended. Due to these additional proposed provisions, the commenter states that it is not clear that future allowance markets will be liquid enough to ensure allowances are available for purchase, particularly in 2026 and beyond. The commenter is concerned that such uncertainty will complicate investment planning for emission controls or alternative generation and is likely to result in increased volatility in allowance markets. The commenter provides that market volatility and fuel price fluctuations can play key roles in how much/how little certain fossil generators are operated in a given ozone season or even in consecutive ozone seasons. In turn, the commenter explains that this can affect the number of future allowances which are budgeted using the dynamic approach. Essentially, they add that these uncontrollable variables can result in a domino effect and a continuous reduction of allowances budgeted year after year due to the nature of how the calculation works for determining the number of allowances which will be available. The commenter adds that, in the event that operation of such a unit was necessary to meet electrical demand, it is not clear that sufficient allowances would be available.

Commenter (0539) contends that replacement resources are also affected by the proposed FIP, subject to allowance allocation shortfalls for existing units and uncertain allowance budgets for planned units under the "New Unit Set Aside" (NUSA) program; as NUSA budgets are not projected beyond 2025, it is unknown if intended replacement combustion turbines and combined cycles will be able to be deployed as currently forecast.

Response:

The EPA's approach to allocating the allowances in each state emissions budget among the state's EGUs, including the approach for reserving portions of each emissions budget in set-asides for potential allocation to certain subsets of EGUs, is discussed in Preamble Section VI.B.9. To the extent that commenters suggest that the state emissions budgets being established under this rule should be increased to enable additional allowances to be allocated to new units or for units that have ceased operations for some period of time and then resume operation, the EPA disagrees, because the state emissions budgets are established in a manner that already provides sufficient allowances for all EGUs, including these EGUs. As discussed in Preamble Section VI.B.4, the state emissions budgets reflect the historical heat input for all of a state's covered fossil fuel-fired EGUs, including units that have subsequently retired as well as heat input for planned new units (in the case of the preset emissions budgets) or actual new units (in the case of the dynamic emissions budgets). The EPA also views the notion that allowances markets would be insufficiently liquid to allow any unit to purchase additional allowances if its need for allowances exceeded its allowance allocation as unsupported speculation that is inconsistent with decades of historical experience under multiple trading programs. However, to the extent that commenters suggest that it would be reasonable to reserve a somewhat larger share of each state emissions budget for potential allocation to new units in light of other changes to the budget-setting and unit-level allocation methodologies in this rule, the EPA agrees. Under the final rule, following a unit's planned retirement (in the case of the 2023-2025 control periods) or actual retirement (in the case of control periods in 2026 and later years), the unit will no longer receive allowance allocations as an existing unit, but in contrast to earlier CSAPR trading programs, the amount of the state's new unit-set-aside will not be increased by the amount of the retired unit's former allowance allocation. If a retired unit were to resume operation and thereby qualify for allocations from the new unit set-aside, there would be fewer allowances available for allocation to new units. As discussed in Preamble Section VI.B.9.a, to address this contingency, in the final rule the EPA has increased the minimum size of each unit's new unit set-aside from 2 percent to 5 percent of the state's emissions budget. Any allowances left in a state's new unit set-aside after allocations to "new" units would continue to be allocated among the state's "existing" units.

Comment:

Commenter (0302) requests that EPA adjust its state's proposed emissions budgets by keeping the proposed allowance allocations for the commenters' affected coal-fired units constant over time. The commenter suggests this is reasonable because the commenter's units already have SCR controls and have historically operated the controls to achieve average emissions rates below 0.08 lb/mmBtu. According to the commenter, the unit-level allowance allocations for its units would decrease in 2026 and beyond as a direct result of EPA assuming SCRs will be installed on all affected units that do not currently have SCRs. The commenter perceives itself as being required to subsidize other affected units that have not installed and operated state-of-the-art NO_X control equipment through a reduction in its own ozone season NO_X allowance allocations.

Response:

To the extent the commenter is observing, first, that the major driver of decreases in a given state's emissions budget across time is that one set of units in the states has opportunities to decrease its emissions by installing and/or optimizing emissions controls, and second, that another set of units in the state may already have installed and optimized such controls, the EPA agrees that such a scenario is possible. However, the EPA does not agree that diversity of this nature among the units in a state is a reason to increase the state's emissions budget, because the budget-setting methodology already accounts for the respective amounts of potential emissions improvement at all the units in the state consistent with the Step 3 emissions control stringency. In other words, if some units in a state are already operating in a well-controlled manner, that fact is already reflected in the state's emissions budgets and does not justify a budget increase. See Preamble Section VI.B.4. Nevertheless, while the scenario identified in this comment does not support increases to emissions budgets, the Agency has determined that the scenario does support an adjustment to the unit-level allocation methodology. Specifically, in the final rule, for each coal-fired unit that is assumed for purposes of a state's emissions budget to have an emissions rate consistent with operation of SCR controls, the historical emissions cap used in the unit-level allocation methodology is no longer simply the unit's maximum emissions over the five-year historical baseline period. Rather, the allocation cap is the lesser of the unit's maximum historical emissions over the baseline period or the unit's "maximum controlled baseline", which is calculated as the unit's maximum heat input over the five-year historical baseline period times an emissions rate of 0.08 lb/mmBtu. The inclusion of the maximum controlled baseline ensures that the allocation caps used for units that did not previously have SCR controls or that did not previously operate their SCR controls in an optimized manner will be more similar to the allocation caps for units that have historically operated SCR controls in an optimized manner, reducing the likelihood that unit-level allocations for historically well-controlled units will decrease simply because a state's emissions budget is being decreased to reflect the potential for other units in the state to reduce their emissions. For further detail on the computation of the maximum controlled baseline and on the role of the allocation caps in the overall unit-level allocation methodology, see Preamble Section VI.B.9.b, the *Allowance Allocation Final Rule TSD*, and the revised Group 3 trading program regulations at 40 CFR 97.1011. The EPA notes that in response to the same comment a parallel adjustment is also being made to the methodology for calculating unit-level allocations from the new unit set-aside to any coal-fired unit that would have been assumed for purposes of a state's emission budget to have an emissions rate consistent with operation of SCR controls. See Preamble Section VI.B.9.c, the *Allowance Allocation Final Rule TSD*, and the revised Group 3 trading program regulations at 40 CFR 97.1012.

Comments:

Commenter (0395) maintains that the Proposed FIP does not perform its statutory goal of encouraging cost-effective reductions by incentivizing good performance from well-controlled sources. According to the commenter, well-controlled coal-fired units are penalized disproportionately for any operation at all, whereas marginally controlled gas-fired units are rewarded. The commenter provides the example, if "Sam Seymour units were to install SCR as contemplated by EPA and become some of the most well-controlled coal units in the nation, EPA's allocation of allowances, because it is based on heat input, not actual NOx emissions which is inconsistent with all prior CSAPR programs, the proposal would provide a surfeit of allowances to marginally controlled gas units at the expense of Sam Seymour."

Commenter (0324) notes Riverside Energy Center units 3 and 4 (ORIS ID 55641) commenced operation in 2020, so EPA only uses two ozone seasons of past emissions data to allocate emission allowances. These units are anticipated to operate at a higher capacity in the future, so EPA should ensure these units have adequate allowances to cover projected capacity growth.

Commenter (0552) states EPA should not impose any significant reductions to the unit-specific OS NOx allowance allocations of well-controlled units due to EPA transitioning to an updated budget or OS NOx allowance allocation process. The commenter provides technical details of its facilities, including specific information on the operations of their RS-5 or RS-6 cogeneration units.

Response:

The methodology for determining unit-level allocations of allowances to existing units is described in Preamble Section IV.B.9.b, the *Allowance Allocation Final Rule TSD*, and the revised Group 3 trading program regulations at 40 CFR 97.1011. With respect to the comment asserting that the allowance allocation methodology is "inconsistent with all prior CSAPR programs" because "it is based on heat input, not actual NO_X emissions", the commenter is incorrect. All prior CSAPR programs have used a unit-level allocation methodology based primarily on historical heat input, with caps based on historical emissions. This rule uses essentially the same allocation methodology, with adjustments to the historical data period considered and with the addition of a second potential allocation cap designed to reduce the likelihood that a state's historically uncontrolled coal-fired units will be advantaged in the unit-level allocation process relative to the state's historically better controlled coal-fired units. Contrary to the comment, if the plant were to install SCR controls, the allowance allocation methodology would not respond to the new controls by transferring allowances from the plant to gas-fired units. With respect to the comment stating that the commenter's plant has so far operated for only two years with heat input that are unrepresentatively low compared to future expected heat input, the EPA notes that because the unit-level allocation methodology uses a rolling historical baseline period of the most recent five control periods for which reported data are available, the methodology will take into account any increases in the units' heat input as they occur over time. With respect to the comment stating that the EPA should not reduce a given plant's allocations because of an updated state emissions budget or unit-level allocation process, the EPA disagrees. The commenter has identified no errors in the budget-setting process for the state and no compelling reason why the commenter's plant should be treated differently from other similarly situated units in the state for purposes of the EPA's default unit-level allocation methodology. The EPA notes that, as discussed in Preamble Sections VI.D.2 and VI.D.3, states have opportunities to submit SIP revisions reflecting alternative unit-level allocation methodologies starting with the 2024 control periods if the states would prefer allocations among the states' units that differ from the EPA's default unit-level allocations.

Comment:

Commenter (0782) requests that EPA clarify that calculations for allowance allocations with respect to natural gas conversion do not include the year(s) or part of a year where the unit is shut down to complete the conversion. In other words, those entities that convert to natural gas should use the heat rate average for the years or portion of the year that the facility was operating and should not include the period of shut down pending conversion. The commenter contends that this will ensure that operators obtain the full benefit from an allowance perspective of undertaking such conversion.

Response:

The methodology for determining unit-level allocations of allowances to existing units is described in Preamble Section IV.B.9.b, the *Allowance Allocation Final Rule TSD*, and the revised Group 3 trading program regulations at 40 CFR 97.1011. As described in all three of those locations (and consistent with the proposal), a given unit's allocation is generally calculated using the average of its three highest total heat input values over the previous five control periods. Thus, a single control period when a unit has unusually low heat input because of an extended outage would not be counted in determining the unit's allowance allocations, assuming heat input was higher in the other four control periods. If the unit does not operate at all in a given control period, then in the control period two years later the unit would not be eligible to receive allocations as an existing unit, but the unit would be eligible to receive allocations from the new unit set-aside for the control period based on its actual emissions during the control period. See Preamble Section VI.B.9.c, the *Allowance Allocation Final Rule TSD*, and the revised Group 3 trading program regulations at 40 CFR 97.1012.

Comment:

Commenters (0257, 0259, 0402) state that in the proposed rule, the EPA proposes to combine the allowances for new units that previously were divided into two new-unit set-asides: one for new units under state authority and one for new units in Indian Country. The commenters are concerned about how this combination would impact Tribal decisions if a state does not replace the EPA' s default allocations with state-determined allocations but goes ahead with permitting new units that use up the set-aside. The commenters assert that, at a minimum, the EPA should make certain that Indian Tribes decision-making will not be constrained by state decisions.

Response:

See Preamble Section VI.B.9.a. That section includes discussion of the approach to set-asides in the final rule, including how the approach reserves portions of a state's allowances budget for existing and new units in Indian country not subject to the state's CAA planning authority. Comments with respect to the treatment of Indian country in this rule are also addressed in sections 1.8 and 2.5 of the RTC.

Comment:

Commenter (0506) notes that EPA's proposed revisions to the procedures for computing unit-level allowance allocations apply only to the Group 3 program. The commenter states that there is no reasonable basis for the EPA to not make the same revisions to the procedures that apply to the Group 2 program, and the final rule should make the same revision to the procedures for allocation of Group 2 allowances.

Response:

Comments on the allowance allocation methodology for the Group 2 trading program are outside the scope of this rule. In this rulemaking, the EPA did not propose any changes to the Group 2 trading program's methodology for allocating allowances from a state's emissions budget among the existing units subject to the state's CAA planning authority.

5.2.1.7 Emissions Monitoring (including common stacks)

Comments:

Commenters (0332, 0341) suggest compliance for mixed configuration units be deferred to 2027 in order to allow them to install individual unit monitoring, depending on EPA's final requirements. Commenter (0332) claims that units in such a mixed configuration that exhaust to a common stack, would likely be unable to install, test and calibrate the required monitoring equipment before the initial compliance period beginning in 2023; resulting in a failure to demonstrate compliance with the backstop rate by 2024 (as currently proposed) because they would be using less accurate data for gauging compliance. Furthermore, commenter (0332) asserts that emissions would likely be overstated for the SCR-equipped units since they would be required to report the co stack data which would not accurately represent the level of SCR-equipped unit emissions. Commenter (0341) also notes some regulatory text modifications: EPA should confirm by adding appropriate language in the preamble or elsewhere that the use of proposed Equation F-28 (Page 20198 of proposed rule) meets EPA's intention to allow units to apportion hourly mass emissions values determined at the common stack in proportion to the individual unit's recorded hourly rate. Further, EPA should also confirm that the term "Hli = Heat Input rate for unit "i", mm BTU/hr" in Equation F-28 means the apportioned heat input calculated by Equation F-21a in 40 CFR part 75.

Commenter (0349) states it cannot feasibly install unit specific NOx monitor installations prior to the common stack to separately monitor the proposed individual unit NOx emissions rate of 0.14 lb/mmBtu. And the commenter states, for its specific units, it is unlikely to meet the limit and install SCR prior to 2024 ozone season. The commenter also asserts that proposed backstop daily rate penalties and the associated methodology for calculating common stack emission rates for sources that cannot install CEMs on the individual units are arbitrary and capricious.

Response:

See Preamble Section VI.B.10 for the EPA's response to these comments. As explained in that Section, the information provided by a commenter asserting an inability to install CEMS at the individual units currently monitoring at a common stack in fact does not demonstrate such an inability. With respect to the commenter's assertion that it would be arbitrary to apply the backstop rate provisions to units unable to install CEMS at the individual units, the EPA notes that comments on the proposal were also submitted by the owners of each of the other facilities that currently monitor at common stacks and that have not announced plans to retire before the backstop emissions rate provisions would apply to the facilities. None of these other comments asserted an inability to install CEMS at the individual units. In the absence of any compelling evidence indicating the existence of relevant facilities unable to install CEMS on the individual units, the assertion that application of the backstop rate provisions to such units would be arbitrary is moot.

5.2.1.8 Prorating for post-5/1 effective date

Comment:

Commenter (0275) states that Group 2 states should not be required to comply with the Group 3 trading program requirements before the effective date of the rule, which should be set outside of the ozone season. The commenter notes that "EPA cites no statutory authority that would allow the Agency to transition Group 2 sources into the Group 3 program before the rule's final effective date." In the absence of an effective rule as of May 1, 2023, sources in Group 2 states would be forced to voluntarily attempt to comply with a rule whose final compliance and recordkeeping requirements are unknown and without a final emissions budget. While EPA has proposed transition provisions, it does not address a situation where the rule is finalized after the end of the 2023 control period. If this were to occur and the May 1, 2023, timing for Group 2 sources to participate in Group 3 was maintained, Group 2 sources would lack certainty about which trading program they would participate in and could result in a situation where these sources cannot fully participate in either the Group 2 or Group 3 trading programs at the end of the control period. The commenter advocates for EPA to maintain the existing Group 2 trading program until the effective date of the final rule, and ideally set the effective date outside of the ozone season to avoid an abrupt transition in recordkeeping and regulatory regimes.

Response:

See Preamble Section VI.B.12.a for a discussion of the final rule's transitional provisions addressing the likelihood that the rule's effective date will occur partway through the 2023 ozone season. In that Section, the EPA explains how the final rule is designed to ensure that no rule provisions that could represent an increase in stringency for any part of the 2023 control period, such as changes in state emissions budgets and assurance levels, take effect before the final rule's effective date. The rule's dynamic budgeting, bank recalibration, backstop daily NO_X emissions rate, and secondary emissions limitation provisions, as well as the modest changes in recordkeeping and reporting requirements, all take effect starting in 2024 or later. In other words, for the portion of the 2023 ozone season prior to the rule's effective date, there is no retroactive application of any new requirement to any source, and the transition from the Group 2 trading program to the Group 3 trading program is a change in name only, with no substantive change in requirements. The commenter does not identify any retroactivity issue or any statutory prohibition on changing the label applied to a substantively unaltered set of regulatory requirements. Contrary to commenter's supposition, as of May 1, 2023, the sources will already know their states' final emissions budgets that apply for the portion of the 2023 ozone season before rule's effective date, because those budgets will be the respective states' budgets under the Group 2 trading program, subject to prorating as provided in the rule so that the 2023 budgets finalized in the rule can take effect as of the rule's effective date. Finally, the Agency has publicly committed to finalizing the rule before May 1, 2023. The commenter's assertions about the hypothetical consequences of an entirely different rulemaking schedule are speculative and unsupported.

5.2.1.9 Initial bank conversion

Comments:

Commenter (0394) states that the EPA should use a less restrictive conversion ratio than proposed. The commenter asserts that the EPA should allow for maximum compliance flexibility based on the stringency of the state emission budgets set out in the proposed rule, the expected timing of the publication and effective dates of the final rule, and the introduction of states to the CSAPR ozone-season NOx trading program that have not been included previously. According to the commenter, the EPA proposes to conduct the conversion of Group 2 allowances based on a target number of Group 3 allowances to be created, equal to the sum of the variability limits in 2024 of the states transitioning from Group 2 to Group 3. The commenter (0394) states that the proposed conversion factor is overly restrictive and substantially more restrictive than the conversion factor implemented in the CSAPR Update, which the EPA states it is using as a model. According to the commenter, the EPA estimates, based on the current quantity of banked Group 2 allowances, that the conversion ratio proposed would be approximately 5.9-to-1. The commenter states that this will have the effect of penalizing sources that met their CSAPR Group 2 emission budgets through emission reductions and built a bank of allowances through early emission-reduction action, which is the very compliance behavior EPA seeks to encourage in the proposed rule. The commenter asserts that banked allowances represent assets that EGU owners have invested in over the past several years to allow for compliance flexibility when needed and to offset costs as needed through the sale of allowances. The commenter claims that seizing these assets through conversion is likely to discourage early emission reductions in the future and risks disruption of the environmental markets.

The commenter believes that if the EPA promulgates state budgets at levels in line with the stringency of the proposed budgets, the EPA should allow for unrestricted use of banked Group 2 allowances for compliance with the revised Group 3 program. In the alternative, the commenter suggests that the EPA should at least use a much less restrictive conversion ratio. The commenter believes this would ease the transition to more stringent Group 3 program for states currently in Group 2 and Group 3 programs and for states entering the ozone-season NOx program. The commenter also believes it would help to avoid or minimize the electric reliability issues that are likely to occur as a result of the proposed budgets. According to the commenter, the state assurance limits will establish an effective upper limit on the number of banked and purchased allowances that can be used in any compliance period, and states also remain bound by the Good Neighbor Provision to ensure that emissions from sources within their borders do not emit in amounts that will contribute significantly to nonattainment by or interfere with maintenance of the 2015 NAAQS in downwind states in future years.

Response:

EPA disagrees with this comment. Creating an overly large initial bank of Group 3 allowances, regardless of the conversion ratio used, would dilute the intended control stringency established in this rule to address states' obligations under the Good Neighbor provision with respect to the 2015 ozone NAAQS. Certainly, given the large existing bank of 2017–2022 Group 2 allowances, allowing these Group 2 allowances to be used for compliance in the Group 3 trading program at a 1:1 ratio would unacceptably dilute the control stringency established by the EPA in this rulemaking. The EPA's rationale for establishing the size of the additional Group 3 allowance bank to be created under the final rule, rather than either a larger bank amount for the reasons advanced by the commenter or a smaller bank amount for other reasons, is fully explained in Preamble Section VI.B.12.b. Comments asserting that limits on the quantities of banked allowances are unnecessary are addressed in Preamble Section VI.B.6. Comments expressing concerns about electric grid reliability are addressed in Preamble Section VI.B.1.d.

5.2.1.10 Provisions for Retirements/Shutdowns

Comments:

Commenter (0354) opposes EPA's proposed change to provide NOx allowances for retired units for only two years instead of five years, stating that it unnecessarily disadvantages the owners/operators that are driven to retire their EGUs in lieu of installing costly emission controls and contributes to uncertainty that hampers their ability to plan for the future.

Commenter (0409) states that the elimination of allocations from retired units addresses the changing generation mix. Related to dynamic budgeting, the commenter explains that this concept is embedded in the CSAPR program to update budgets based on the changing EGU fleet. Previously, CSAPR allowed a source to keep allocations for five years from retirement (two consecutive control periods of nonoperation plus three years). The Proposed FIP shortens allocation retention to "only two full control periods of non-operation." This approach fails for several reasons. First, according to the commenter, nonoperation is not the same as retirement. Idling may occur for various reasons such as changes of ownership or market conditions. In fact, the commenter contends that the proposed FIP adds a layer of complexity to nonoperation conditions. Where non-SCR units do not have enough time or financing to add controls, operators may be forced into nonoperation in future ozone seasons. In addition, the proposed budgets are tight. According to the commenter, they will force units off-line during summers that will continue to be needed for capacity in winter months. It is also possible that the cost to dispatch certain units – due to pricey CSAPR allowances – may lead to an operational unit, bid into the market, that is not chosen for dispatch. The heat input of that viable unit would be zero. These units are not "retired," however; the CSAPR program would eliminate them from the allocation pool. Moreover, we note, in support of a longer retired unit allocation approach, that retaining CSAPR allocations for a longer time period may incentivize retirements. The commenter states that they are aware of numerous instances in which the CSAPR program was a meaningful factor as a retirement benefit considered in company strategy. They add that, with depleted allocation banks and tight budgets, they anticipate such an incentive would only be stronger in coming years.

Commenter (0332) states EPA should also consider whether to allow units that retire in 2022 to retain their allowances for the initial compliance period—until 2026—instead of removing those units from the program entirely. The EPA may also consider whether the Agency should set a price ceiling on allowances within any final rulemaking in order to control compliance costs, which are ultimately passed on to customers.

Commenters (0499, 0506, 0533, 0541) state that units that do not operate for two consecutive ozone periods should continue to be granted allowance allocations for a total of five control periods, as provided in the Revised CSAPR Update. In the Proposed FIP, the commenters note that such EGUs will not receive any allowances beyond two control periods of non-operation within an ozone season. The commenters believe this proposed restriction, along with the numerous other proposed limitations, will severely constrain the allowance market and may not have the effect of reducing NOx emissions that EPA intends. Commenters (0499, 0506, 0533) add that it may encourage a unit that might be idled during the ozone season to be started up unnecessarily so that the unit can continue to be eligible for NOx allowances and be included in the state budget. According to the commenters, both the regulated utilities and the customers they serve would incur unnecessary costs as a result. The commenters state that it is important for the EPA to recognize that idled units are not the equivalent of retired units, whereas under the proposed FIP, retired units, idled units, and units offline due to outages are all treated the same for state budget purposes in that the state budgets would be recalibrated to exclude those units. The commenters point out that this is problematic for EGUs that will come back online in future years. Commenters (0499, 0533) add that unlike in past CSAPR trading programs, the EPA is not proposing to include EGUs that retire prior to 2023 in its calculation of the state budgets, nor does EPA appear to grant units that retire prior to 2023 or prior to January 1, 2024, any allowances for years after their retirement dates. The commenters state that for such EGUs, the EPA should adopt the same approach it has taken in the past with respect to known retirements, which is to include such EGUs in the state budgets if they operated at any time during the baseline period and grant them allowances for the same time period as EGUs that retire after January 1, 2024.

Response:

The EPA disagrees with the comments advocating for continued allocation of allowances to sources for five years past the sources’ last year of operation. The assertions that the EPA has never before continued to allocate allowances to retired units for less than five years are incorrect: in the Revised CSAPR Update, the EPA coordinated the end of allocations to units with known planned retirements in the same control periods in which the units’ retirements were taken into account for budget-setting purposes. The EPA’s reasons for no longer providing allocations to retired units for more than two control periods under this rule, including consideration of the possible effects on units’ retirement incentives, are explained in Preamble Section VI.B.9.b. To the extent the commenters are suggesting that the retired units in a state somehow have a greater need for allowances than other units in the state that continue (or begin) to operate, the EPA views the suggestion as illogical, because it is readily apparent that operating units need allowances to address ongoing allowance surrender obligations while retired units do not. Moreover, any state that wishes to allocate the allowances in the state's budget among the state's units differently than the EPA's default allocations may submit a SIP revision for that purpose starting with allocations for the 2024 control period. To the extent the commenters are actually advocating for continued allowance allocations to the retired units in a state for additional control periods without commensurate reductions in the allocations to the state's operating units, the comments effectively represent a disagreement with either the EPA's findings concerning the appropriate Step 3 control stringency or the methodology for calculating the quantities of allowances that properly reflect the identified Step 3 control stringency. Comments concerning the Step 3 control stringency are addressed in Preamble Section V and section 4 of this RTC. Comments concerning the methodology for setting budgets to reflect the Step 3 control stringency are addressed in Preamble Sections VI.B.1 and VI.B.4 as well as earlier subsections of this RTC section.

Comments:

Commenter (0290) requests that the EPA allow coal-fired units and gas-steam units that attest to a reasonable shutdown date to operate beyond the 2026 implementation date without a SCR. The commenter also requests that these units maintain allowance allocations beyond 2026 to the agreed upon retirement date consistent with the approach of the allocations of 2024. The commenter writes that closing such large amounts of existing dispatchable generation in such a short timeframe raises electric grid reliability concerns. The commenter adds that the alternative of adding SCRs to these units for a short amount of time is cost prohibitive and may not be achievable with the current commodities, services, and labor market constraints.

Commenter (0324) states EPA should have a process available to address the scheduled retirement dates having the potential to shift by a few months. At a minimum, the commenter recommends that, for the 2023 and 2024 state budgets and unit allocations, EPA should use the most recent available information on scheduled retirement dates at the time of finalizing the rule. Otherwise, any lags in actual retirements from publicly announced dates could result in a budget shortfall.

Commenter (0275) states EPA should not set 2023-2026 budgets that assume unit retirements not yet approved by regional independent system operators. The commenter also states EPA should exclude from its recalibration procedure the commenter's units, or units at other sources subject to federal consent decrees with similar provisions requiring the surrender of CSAPR allowances.

Commenter (0300) also suggests that EPA allow the consideration of planned, near term EGU retirements that may extend past implementation of the proposed dynamic budgeting to avoid costly stranded assets. The commenter maintains that it is inconceivable to require companies to spend millions of dollars for control of emissions at sources that will be permanently shut down within 3-5 years after the initial compliance deadline, stranded costs that will be passed on to ratepayers already struggling with the impacts of inflation.

Commenter (0351) states that all the new trading mechanisms (including the proposed backstop daily emission rate) would reduce overall emissions, mitigating any effect of allowing additional compliance flexibility for units that retire beyond 2028. The commenter instead suggests 2032 as the retirement year because that is the year prior to the year by which severe nonattainment areas in downwind states must comply with the 2015 Ozone NAAQS.

Commenters (0499, 0533) state that for EGUs that are scheduled to retire in the next 10 years, the state budgets should not be based on an assumption that such units will install post-combustion controls, whether SCR or SNCR. The commenters note that utilities are already making long-term plans for unit retirements as they transition to a cleaner fleet, and it is unreasonable for the EPA to mandate that EGUs install expensive control technology for units that only will have short remaining operating life. The commenters suggest that the EPA provide a reasonable and cost-effective offramp for such units in the Proposed FIP. Commenters (0499, 0533) add that by setting state budgets based on an assumption that units without existing post-combustion NOx controls will meet rates that are only achievable through the installation of control technology, the EPA is unreasonably constraining those budgets. The commenter assert that the EPA should provide flexibility to EGUs that will retire by 2030 and, accordingly, adjust the 2026 and later budgets to accommodate such units' continued short-term operation without the installation of post-combustion NOx control technology.

Response:

See Preamble Section VI.B.4.a for EPA's response to comments suggesting that preset budgets should not include announced retirements because of the possibility that retirement plans could change.

See Preamble Section VI.B.1.d for the EPA's response to comments regarding how the rule should address coal-fired units without existing SCR controls, both with respect to the timing for implementation of the backstop daily emissions rate provisions and the reflection of the units' emissions reduction potential in state emissions budgets. Further discussion of these topics is also provided in Preamble Sections VI.B.4 and VI.B.7.

See Preamble Section VI.B.1.d for the EPA's response to comments concerning electric grid reliability.

5.2.1.11 General Trading Program and Impacts of the Combination of Trading Enhancements, Overcontrol

Comments:

Commenter (0492) supports EPA's inclusion of safeguards – the dynamic adjustments of the emissions budgets annually, the recalibration of the allowance banks, the unit-specific backstop daily emissions rates, and the secondary emissions limits to implement the state-wide assurance levels, designed to maintain the stringency of the program over time even as the EGU fleet's composition and usage changes and to ensure that EGUs implement the expected emissions controls continuously throughout each day of the ozone season. The commenter also explains that their inclusion is consistent with EPA's broad FIP authority, as the CAA authorizes a FIP to include enforceable emission limitations or other control measures, means, or techniques that provide for attainment of the relevant NAAQS. According to the commenter, caselaw makes clear, that "[w]hen the EPA disapproves a SIP and proposes a FIP, it stands in the position of the state with all the same requirements and powers the state had in initially drafting its SIP." The commenter adds that states are free to adopt backstop measures to guarantee that emissions limits imposed on sources are actually achieved, and in a similar vein the EPA is proposing in this FIP the dynamic budgets, the daily emissions rate limits, and the other safeguards to ensure that the emissions reductions needed under the Good Neighbor Provision to aid downwind states are consistently achieved. The commenter states that because EPA has authority in a FIP to fill a gap left by the state, the EPA has authority to adopt the proposed safeguard measures.

Commenter (0515) supports the EGU allowance trading programs created by the Proposed Rule because it provides greater flexibility relative to more prescriptive, 'command-and control' forms of regulation. The commenter adds that shifting generation from higher-emitting units to lower- or non- emitting units allows for more significant emissions reductions than would be possible through unit-specific regulatory requirements, all while retaining sufficient operational flexibility to meet electricity demand.

Commenters (0379, 0503, 0758) provide general support for the modifications to the allowances trading framework. Commenter (0379) claims that inadequate caps and review of banked allowances and the continued decline of their prices has meant that it has been cheaper and easier for a facility operator to buy emission allowances than to start running controls, resulting in continued high levels of ozone pollution in many areas, and feels this rule will address this concern. Commenter (0503) supports EPA's choice to make a complimentary annual recalibration of the allowance bank; arguing that allowances are an asset and are in part due to any and all efforts taken by power plants to reduce their emissions through, amongst other efforts, optimization of the existing controls. The commenter adds that some amount of excess or banked allowances are an important market buffer that helps to protect against allowance price volatility. However, too many allowances, according to the comment, dilute the cost and disincentivizes the optimization of the installed controls. The EPA's proposed recalibration of the allowance bank prevents the dilution of allowance costs and incentivizes continued optimization of the installed controls – which are vitally important to attainment of the NAAQS.

Commenter (0215) states that both the seasonal mass cap and the daily rate backstop may be too lenient to drive timely attainment of the standard. The commenter suggests that EPA do one of the following to ensure optimal emissions reductions: lower the seasonal mass cap; establish an overall ozone season NOx rate cap along with the mass cap; lower the daily backstop emission rate; or require states to submit Good Neighbor State Implementation Plans (SIPs) with a rate that is reflective of the ability of the individual units in each state to optimize the controls. The commenter also states that the surrender ratio for additional allowances is not a true penalty and suggests that EPA strengthen the surrender ratio to a value of 10:1.

Commenter (0551) poses the question whether EPA's enhancements will negatively affect the market for allowances; claiming that the proposed enhancements could significantly affect the availability of allowances and incentivize different market behavior than existed under previous versions of CSAPR; adding that already, the market for Group 2 and Group 3 allowances has seen considerable volatility since the release of the Proposed Rule.

Commenters (0409, 0519) strongly support the inclusion of flexible mechanisms to allow EGUs to more efficiently and effectively secure compliance with interstate ozone transport obligations, however, according to the commenters, the Proposed FIP imposes significant constraints that undermine any flexibility provided by a trading program. The commenters urge the EPA to amend the FIP to ensure sufficient compliance flexibility. The commenters support robust trading program provisions, which they believe are essential for EGUs to achieve required emissions reductions while maintaining grid reliability, and bolster on their (commenter 0519) record of achieving environmental targets when flexibilities are provided (*e.g.*, by way of targets and timelines).

Response:

See Preamble Section VI.B.1, including Section VI.B.1.d, for an overall discussion of the changes made in the final rule to increase EGU compliance flexibility while continuing to achieve the Step 3 control stringency for EGUs adopted in the final rule. Further discussion of the specific changes is included in Preamble Sections VI.A.2.a (timing of emissions reductions achievable through installation of new controls), VI.B.4 (budgets and budget-setting), VI.B.6 (allowance bank recalibration), and VI.B.7 (backstop daily NO_X emissions rate provisions).

Comment:

Commenter (0330) states that, at §97.1006(c)(1)(ii)(B), with regard to a failure to hold sufficient allowances to cover emissions, EPA states that "... 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." It is our understanding that the maximum penalty under the Clean Air Act is currently $109,024 per violation per day. When merged with the 153-day length of the ozone season, the resulting maximum penalty for a single allowance shortfall is $16,680,672. The commenter believes that the preceding is clearly an absurd result and will likely further exacerbate the potential market concerns as previously discussed. Commenter states that the preceding penalty provision is additional to that at §97.1006(c)(1)(ii)(A), which via reference to §97.1024(d) requires the surrender of two additional allowances for each ton of excess emissions. The commenter contends that, in a market-based program utilizing allowances, imposing a penalty beyond the direct surrender of additional allowances is problematic if one cannot use the market as intended to meet their compliance obligation. The commenter recommends that the EPA consider eliminating the penalty provision at §97.1006(c)(1)(ii)(A) entirely or stipulating a far more reasonable cap on the potential financial penalty. At a minimum, the commenter suggests that the EPA clarify the penalty calculation methodology if an allowance shortfall is realized at the end of the ozone season; if allowances cannot be secured due to a shortage in the market and/or the pricing of the allowances is exorbitant, then how would penalties be assessed? The commenter notes that, such lack of clarity will further exacerbate market volatility.

Response:

The specific penalties for noncompliance under the Group 3 trading program that commenter references have been included in every CSAPR trading program since 2011 as well as in previous trading programs. These penalty provisions were not reopened by this rulemaking, and as such, this portion of this comment is out of scope. Nonetheless, the EPA disagrees with the suggestion that changes should be made to the Group 3 trading program's provisions for penalties in the event a source fails to hold the required quantity of allowances for surrender as of the allowance transfer deadline following each control period. The fundamental compliance requirement under the EPA's trading programs is to hold a required quantity of allowances as of a specified deadline following each control period. If failure to meet this compliance requirement was not defined to be a violation of the Clean Air Act, the EPA would be unable to address instances of noncompliance and therefore would be unable to ensure achievement of the required emissions reductions. With these provisions in place, compliance incentives have been strong and compliance has been very high, such that the potential consequences of noncompliance that the commenter considers "absurd" have not occurred.

The commenter's separate suggestions that compliance with the Group 3 trading program as modified in this rule might not be possible because of a shortfall of allowances are speculative and contrary to the EPA's analysis for this rule as well as decades of historical experience with other trading programs.

Comment:

Commenter (0326) states EPA's constant reorganization of the trading program negates the predictability and certainty the program needs to be successful. The commenter recommends that EPA create a single region-wide trading program, or two programs if needed, but pick a scheme and stick to it.

Response:

The requirements of the Good Neighbor provision and the analyses that have caused the EPA to conclude that sources in certain states must make incremental emissions reductions to address the Good Neighbor provision with respect to the 2015 ozone NAAQS, and to conclude that sources in other states do not need to make incremental emissions reductions for this NAAQS, are discussed in Sections II through V of the preamble.

Comment:

Commenter (0291) questions the effectiveness of the proposed enhancements to the Group 3 trading program. The commenter briefly discusses the previously CSAPR noting that was an aspect/component to the CSAPR (similar to the component proposed in the proposed rule) to try to make the seasonal cap-and-trade program effectively reduce emissions when needed for ozone compliance. The commenter explains that in order to limit a state's contributions to downwind exceedances CSAPR included assurance levels that act as a cap on a state's NOx emissions during the Ozone Season, and if a state exceeds their assurance level, then sources that exceed their assurance levels within that state will be assessed a 3-to-1 allowance surrender on the exceedance of the assurance level. If a source exceeds their assurance level but the state does not, there is no penalty. Commenter (0291) states the last version of CSAPR was not tested against time, so it is not clear whether it worked as planned or caused unintended impacts on the market. All this accounting and assessment is unnecessary for an episodic cap-and-trade program.

Response:

The comments asserting that the effectiveness of the EPA's previous seasonal trading programs is unknown are vague. The suggestion that the EPA should adopt an entirely different type of compliance mechanism across multiple states to address interstate ozone transport issues based largely on the commenter's perception that a single state was previously able to implement that different type of compliance mechanism (for a purpose other than addressing interstate ozone transport) is not compelling.

Comments:

Commenter (0354) states that the proposed changes to the trading program (i.e., dynamic budgeting, the daily backstop rate, annual banking recalibration, and electricity generation shifting) would eventually result in illegal overcontrol since the NOx emissions trading program already includes a compliance assurance mechanism set at a level to ensure that the needed NOx emission reductions are provided. The commenter argues that these changes would result in a shortage of allowances necessary to provide reliable and affordable electricity to consumers.

Commenter (0395) writes that the proposed "enhancements" to the existing CSAPR program are unrelated to ozone reductions and are simply attempts to make the program itself more stringent and less flexible, equating to a command-and-control rule. The commenter states that under the EPA's established framework, EPA must perform multiple checks to ensure it has not overstepped its authority, including confirmation that upwind emissions contribute one percent or more of the NAAQS, confirmation that the identified reductions are cost-effective, and confirmation that the reductions are not more than necessary for the downwind state to come into attainment. The commenter writes that EPA has not performed these checks on its authority with respect to its proposed "enhancements," and therefore, the new elements result in unlawful overcontrol.

Commenter (0554) states that EPA's proposed enhancements eliminate the flexibility needed for an emission allowance market to work, thus eliminating the benefits of the market. The multiple layers of backstop limits proposed, combined with new restrictions on the holding and use of allowances themselves, are likely to leave individual facility owners with too few choices for trading to function properly. While some constraints are needed to ensure the program accomplishes its intended goals and satisfies Clean Air Act requirements, unnecessary and duplicative constraints will impede the formation of a viable market and the associated benefits of trading. The combined effect of the many proposed enhancements is also likely to result in over-control, since the enhancements will tend to force greater emission reductions than the levels EPA evaluated in its over-control analysis. The commenter asks EPA to "either eliminate the enhancements altogether or demonstrate how the proposed enhancements will not impede the development of a viable trading market and result in unlawful over-control."

Commenter (0524) argues that without a clear nexus between the "enhancements" proposed by EPA and significant contribution, the enhancements will lead to overcontrol. The commenter states that ongoing changes to its electric generating fleet as it adds more renewables as well as enhancements that limit the flexibility of the trading program could threaten electric reliability.

Commenters (0541, 0533) support the continued use of trading programs to address any remaining state obligations under Section 110(a)(2)(D)(i) of the CAA and write that the electric sector has already made significant reductions under EPA's previous good neighbor trading programs. The commenters clarify that although they support the use of a trading program in general, the proposed "enhancements" are overly restrictive and result in unlawful overcontrol of regulated sources. The commenter (0541) states that the availability of dispatchable fossil fuel-fired units is necessary to provide both baseload power and also the intermediate and peaking capacity capable of ramping during the daily and seasonal transition to intermittent renewable resources and energy storage, and EPA should reassess the proposed rule and consider the resulting risks to grid reliability. The commenter (0533) elaborates a trading program allows companies to make additional allowances available by overcontrolling units where it makes sense to do so and retiring/reducing utilization of other units. However, EPA's proposed restrictions to the program would serve to limit the number of allowances available in the market, leading to increased volatility and sources stockpiling allowances. Any allowances that are available in the market likely would trade at exceptionally high prices based on the current Group 3 NOx allowance prices. In light of current economic circumstances for consumers, such as inflation, and reliability concerns for EGUs, it is important for EPA to fully consider the costs of the Proposed FIP on EGUs and consumers.

Commenter (0519) argues that the proposed "enhancements" will result in overcontrol by increasing the stringency of the program over time. The commenter states that the proposed rule will "attribute fewer emissions reductions to all banked allowances and prevent units from obtaining credit for their reductions, while also limiting the total number of allowances available to facilitate compliance, undermining the intended flexibility-enhancing nature of these measures." The commenter believes that "Absent the flexibility provided by trading, EGUs will be forced to choose between accelerating retirements or, if retirement is not possible for reliability reasons, prolonging the life of fossil units through the installation of costly controls." The commenter disagrees with EPA's justification of the new constraints, arguing that "The Clean Air Act vests EPA with authorities for the express purposes of remedying implementation plans that are inadequate to mitigate significant interstate pollutant transport. Rather than depriving EGU s in 26 states of necessary and environmentally beneficial compliance flexibility in the anticipation of later problems, EPA should exercise its authorities under the Act and undertake a state-specific rulemaking if and when a problem actually occurs. Simply put, CAA Section 110(a)(d)(D) does not require EPA to promulgate or maintain identical FIPs, and EPA should not impute the problems that arise in one state to others in an effort to do so."

In addition to the likely perpetual reduction in allowances each year due to dynamic budgeting (discussed in section 5.2.1.2 of this document), the commenter (0302) states that the proposal also lacks any mechanism to ensure that a state does not over-control. According to the commenter, there is nothing in the proposal that would prevent the allowances in a state to become so low as to drop below the threshold of the state contributing one percent of the NAAQS to downwind areas or if the downwind monitors reach attainment. The commenter reports that this is especially important for Missouri and Oklahoma, which are only marginally above the one percent threshold based on EPA's most recent modeling. The commenter states that, as units install controls over time, restrict operations during the ozone season, or retire units, the actual impacts on downwind receptors will decrease. The commenter notes that the dynamic budgeting process and stringent allocation reduction process would most likely result in that state over-controlling with no exit ramp from future allowance allocation reductions.

Response:

See Preamble Section V.D.4 for the EPA's response to comments on alleged overcontrol. For discussion of comments regarding the EPA's legal authority, see also Preamble Section III. For discussion of other comments concerning the final rule's enhancements to the Group 3 trading program, see also Preamble Sections VI.B.4 (budgets and budget-setting), VI.B.6 (allowance bank recalibration), VI.B.7 (backstop daily NO_X emissions rate), and VI.B.8 (secondary emissions limitation).

Comments:

Commenter (0373) states that the proposal places unnecessary restrictions on emissions trading. The commenter writes that the proposed requirements (e.g., the backstop NOx daily emissions limit, the annual recalibration requirement for banked allowances, and the proposed secondary NOx limit for each unit) will increase compliance costs and could cause idling of coal units during the summer, when electricity demand typically spikes. The commenter urges the EPA to eliminate the proposed trading restrictions, since doing so would help reduce some of the pressure for coal units to retire prematurely.

Commenter (0346) describes the impacts to the power generation sector and describes the proposed rule as "inflexible" and taking a "technology-forcing" approach. The commenter writes that even well-controlled coal-fired units with SCRs will be forced to operate at reduced capacity factors due to the "scarcity" of NOx allocations, while dynamic budget setting will reduce state budgets, bank recalibration will minimize the allowances sources can save, and a first-time daily NOx rate "ensures higher emitting NOx units cannot run." The commenter writes that the proposed rule leaves no room for flexibility and will force technology installations or retirements if units cannot afford retrofits.

Commenter (0372) suggests the following:

- Re-establishing the ozone season NOx banked allocations.
- Using 30-day rolling averages for ozone season NOx.

Commenter (0414) writes that the proposed emission trading program contains a number of requirements that will limit the flexibility of and increase the compliance costs of the additional NOx reductions required under the proposed rule. The commenter states that these are unnecessary, inflexible, burdensome, and costly enough that they could force the shutdown of additional dispatchable coal fired EGU generation on an accelerated time schedule, thus exacerbating grid reliability risks. The commenter recommends that EPA reevaluate the need for all of these new emission trading requirements applied concurrently and remove those limitations that are unnecessary for remedying downwind ozone nonattainment.

Commenter (0554) requests that additional flexibility be incorporated into the proposed rule on the grounds that this is "critical to the success of a market-based trading program and the additional constraints on flexibility inherent in EPA's enhancements will likely stifle the market for allowances, robbing affected sources of the ability to choose their path to compliance based on unit-specific considerations regarding cost, feasibility, and other factors."

Commenter (0512) states that the proposed "enhancements" to the interstate trading program will hamper the function of the program and are unnecessary to achieve compliance with the Act. The commenter relates that these enhancements include imposing a "backstop" daily emission rate of 0.14 lb/MMBtu for coal steam units greater than or equal to 100 MW, and, starting in August 2024 before the 2025 ozone season, "dynamic budgeting" that will continuously ratchet down emissions budgets, effectively mandating greater emissions reductions over time.

Together, the dynamic budget and annual allowance bank recalibration (discussed in section 5.2.1.3) create unnecessary regulatory uncertainty for EGUs. Because the budget and the allowance bank will be revised yearly, the commenter (0533) notes that EGUs will have insufficient time to make any necessary adjustments to comply with future allocations. The commenter asserts that this is further complicated by potential price volatility arising from annual readjustments of the budgets. As noted above, the commenter states that the price of Group 3 allowances increased dramatically in recent months after the announcement of the Proposed FIP. With yearly recalibrations, the commenter explains that this same volatility could potentially continue throughout the program, thereby injecting significant uncertainty and inefficiencies into electric generating companies' planning processes. The commenter adds that such uncertainty and volatility may then be reflected in higher prices to consumers.

Commenters (0499, 0533) contend that the proposed FIP's dynamic budget (discussed in section 5.2.1.2 of this document) and annual allowance bank recalibration, as proposed, will unnecessarily restrict the allowance market, hinder EGU operators' abilities to plan for future year operations, and will arbitrarily tie the program to operations in a single year that may not be characteristic of normal EGU operations. As such, the commenters urge EPA to reconsider these portions of the Proposed FIP. Group 3 allowances under the current program are already scarce and those that are available are selling at a much higher price than allowances under the other CSAPR programs. The commenters explain that this concern is compounded by the dynamic nature of the budgets and the allowance bank recalibration. If coalfired units must operate at a reduced capacity due to a lack of sufficient allowances, the state budget in two years will reflect that decrease and the state budget will shrink, as will the corresponding unit-level allowance allocations. According to the commenters, eventually, such units will have little to no allowances and will be unable to effectively operate.

Together, the commenters (0499, 0533) state that the dynamic budget and annual allowance bank recalibration create unnecessary regulatory uncertainty for EGUs. The commenters explain that, because the budget and the allowance bank will be revised yearly, EGUs will have insufficient time to make any necessary adjustments to comply with future allocations. The commenters add that this is further complicated by potential price volatility arising from annual readjustments of the budgets. As noted above, the commenters note that the price of Group 3 allowances increased dramatically in recent months after the announcement of the proposed FIP. According to the commenters, with yearly recalibrations, this same volatility could potentially continue throughout the program, thereby injecting significant uncertainty into utilities' planning processes.

Commenter (0330) states the combination of dynamic budgets, the daily backstop penalty and annual bank recalibration are likely to seriously hamper the Group 3 allowance market. Large utilities, including CMS Energy, routinely forecast future emissions levels. Static budgets, without daily backstop penalties or recalibration of the bank, allow utilities to forecast allowance surpluses or shortfalls with reasonable accuracy, well in advance of the compliance period. This facilitates the early selling and purchasing of allowances in the market with reasonable confidence in the number of such allowances.

Under the proposed rule, using the 2025 compliance period as an example, the commenter (0330) states that the initial allocations would not be known until March 1, 2024, approximately 14 months prior to the start of the 2025 compliance period. Furthermore, the commenter notes that bank recalibration will begin with the 2024 compliance period and would occur sometime after June 2nd and no later than August 1st of a given compliance period. Thus, the commenter states that the bank recalibration for the 2025 compliance period may not occur until August 1, 2025, just 2 months before the end of the compliance period. According to the commenter, unless a utility is highly confident that their initial allocations will be sufficient to cover its compliance obligation, absent any banked allowances, it is unlikely they would choose to sell 2025 and earlier vintage allowances any earlier than August 1, 2025. The commenter states that this is exacerbated by the daily backstop penalty for coal-fired SCR equipped units, as allowance needs based upon emissions projections could be rendered inaccurate due to unforeseen startups/shutdowns or malfunctions of the SCR. The commenter contends that switching a market design from being reasonably predictable months in advance of the compliance period to having no predictability until the compliance period is well underway or over will create a non-functioning, highly volatile market.

On the surface, the commenter (0330) states that the preceding timing may not seem problematic in that allowance surrenders for the 2025 compliance period are not due until June 1, 2026. However, the commenter contends that, if you are a utility which is projected to be short on allowances, and such becomes reality during the 2025 compliance period, there is risk that you may not be able to timely purchase allowances to cover projected shortfalls during the 2025 compliance period. If there are no other actions available to minimize NOx emissions during the compliance period, the commenter provides that the only other certain action a utility must face will be curtailment of operations. The commenter believes that, with the expected volatility and uncertainty in the allowance market, few utilities will want to assume the speculative risk that they will be able to purchase such allowances after the ozone season ends. The commenter recommends that the EPA not create markets that it knows will cause reliability issues, particularly in an environment like now where supply chain issues make it difficult to build replacement renewable generation sources that will not be subject to the whims of the Group 3 market.

Commenter (0330) states that the preceding must also be considered in light of the extreme volatility that has been observed in the Group 3 allowance market since publication of the proposed rule. Since May 2, 2022, through June 15, 2022, the commenter reports that allowance pricing information from Amerex indicates that CSAPR NOx Ozone Season Group

3 mid-market prices (*i.e.,* the average between bid and ask prices) has climbed from $15,000 per allowance to $32,500 per allowance. The commenter suggests that this rapid rise in prices is likely driven by the proposed FIP and uncertainty around future allowance needs and a general reluctance to sell into the market.

Commenter (0411) states it will be difficult to manage unit operation to meet allowance allocation thresholds, and further suggests that allowance bank calibration discourages trading. Foremost, the commenter claims that the proposal creates tiered operational risks for units – the first tier of risk is known since it involves operating a unit up to the level of the allowance allocation for the unit; the second tier involves variable and increasing risk of not being able to purchase needed allowances when entities operate above their unit allocations when power and reliability is most needed; and the third tier of risk is when an entity believes that they will not expect to find allowances available to purchase and a unit must be shut down. The commenter recommends the following changes to the proposed rule to address these issues: (1) Eliminate the backstop provision or at a minimum eliminate the backstop provision for units that retire before controls can be deemed cost recoverable if installed, (2) Eliminate dynamic budgeting. If the proposal is a "full remedy" dynamic budgeting is not necessary and EPA already has a mechanism for reducing the state allocations via rulemaking, and (3) Eliminate the 10.5% excess allowance cap or, at a minimum raise the cap to 21%.

The commenter (0500) also notes EPA states that annual bank recalibrations are preferable as compared to Progressive Flow Control ("PFC") used under the NOx Budget Trading Program as PFC introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions. In reality, the bank recalibration provides more uncertainty as a banked Group 3 allowance may not even be available in future years to provide any compliance value, much less a reduced value as we saw under PFC. The commenter states that the EPA has promoted the fact that a market -based compliance mechanism is a straightforward and cost-effective method for emission reductions. According to the commenter, the dynamic budget aspect of this proposal contradicts EPA's stated preference for market-based compliance mechanisms and adds significant uncertainty regarding the availability and cost of future allowances.

Commenter (0528) states the combination of the backstop emissions rate, dynamic budget, and annual allowance bank recalibration (of 10.5 percent of the sum of the state emissions budgets) effectively eliminates the allowance market and impairs EGU operators' ability to plan for future year operations.

Commenters (0409, 0428, 0541, 0553, 0547, 0798) argue the FIP would use the shell of the CSAPR program in name only. They state that the curtailment of allocations would strip "flexible" trading. According to the commenters, not only do tight budgets and the generation shifting reductions contribute to allowance shortfalls, but the EPA's new concepts trim any remaining "fat," if there really will be any remaining. The commenters claim that none of these features are necessary.

Commenter (0409) adds in the past, commenters have claimed that a trading program will not lower emissions on high ozone days due to SCR non-operation. The commenter states that in this rulemaking, the EPA recognizes that past studies showed a lack of evidence of SCR nonoperation but postulates that "this problem could become more prevalent in future years relevant to this action." According to the commenter, the proposed FIP provides no reasonable basis for this prediction. According to the commenter, NAAQS nonattainment, Regional Haze, New Source Review, and state operating permit requirements are among the means presently in EGU Title V permits to ensure SCR operation. The commenter states that the EPA should acknowledge that these federally enforceable measures are in place exactly for the purpose of assuring control device operation, and it is not necessary to impose duplicative requirements on this highly regulated sector.

Commenter (0396) asks the EPA to consider the significant legal risk it takes on by proposing the untested "enhancements." According to the commenter, the D.C. Circuit and the Supreme Court have already reviewed the EPA's prior CSAPR programs and provided significant guidance on what the program may include, so the EPA should be able to design a program more clearly within the confines of that jurisprudence and still meet the requirements of the CAA. The commenter adds that prior litigation over EPA's CSAPR program makes it clear that the EPA's creative attempts to embellish the program are invariably challenged and often rejected in court.

Commenter (0289) states because facilities generally try to ensure their compliance with the CAA requirements due to the highly punitive penalties that they would incur if they do not, they tend to operate at even cleaner levels than required to have a compliance margin. This provision could potentially push facilities into making decisions to exorbitantly increase their cost to run significantly beyond what the market would typically require, because of the potential for a violation if they run too much. The commenter understands the intent of these four new assurance provision requirements in the Proposed FIP; however, it is unnecessary to include all four of them. Together, the provisions would be unworkable, will negate the entire purpose of a trading program, and will result in much higher costs than needed to meet the goal the rule is intended to achieve. The commenter recommends that EPA pick one or at most two of the proposed new requirements. The commenter states their belief that the cap on the bank may be the best choice, but EPA should evaluate and determine what cap percentage is appropriate.

Commenter (0302) states the proposed FIP unfairly penalizes "good actors" and rewards "bad actors". The commenter sees itself as a notable example of a good actor that is being unfairly penalized for having operated state-of-the-art pollution control equipment on our electric generating units. Specifically, the SCR systems on Iatan Units 1, Iatan Unit 2, and Hawthorn Unit 5A operate year-round, not just during the ozone season, at historically low NOX emission rates. In fact, the NOx emissions from all three units are well below each Unit's stringent federally enforceable NOx emission limitations. Over the last five years, Iatan Unit 1, Iatan Unit 2, and Hawthorn Unit 5A have had average NOX emission rates of 0.067, 0.052 and 0.066 lb/mmBtu, respectively. Even though the commenter has voluntarily operated these units well below the permitted NOx emission limitations, the EPA is proposing to reduce the commenter's allowance allocations, claw back the allowance bank, and impose a new daily NOx emission limitation. The commenter choses to operate well below the permitted NOx emission limitations because it was the right thing to do. The commenter should not be adversely penalized for being a good steward of the environment.

Commenter (0553) continues, foreshadowing how the Proposed FIP may prove unworkable for EGUs, the 2021 Revised CSAPR Update Rule included provisions that have impacted the market's ability to function efficiently. Currently there is very little liquidity and the market price for Group 3 allowances is over ten times what it was just a year ago. The Proposed FIP would compound the problems currently experienced in the Group 3 program by imposing multiple new layers of complexity and new penalties which will effectively reduce the pool of available allowances for compliance below the actual state budgets. These restrictions add uncertainty and concern for the ability of sources to comply from year-to-year. Duke Energy is concerned that these provisions will result in very costly compliance and an allowance market that may not be able to effectively function.

Commenter (0553) argues EPA's proposed "enhancements" to the NOx Budget Trading Program try to address a situation that does not exist or will be largely corrected by allowing market forces to function. The EPA's own analysis has shown that, by and large, EGUs are operating installed controls to effectively reduce NOx emissions during the ozone season. In each of the established programs, EGUs have taken the steps to install and operate controls and over time NOx emissions have trended down, building significant margin below the budgets established to meet Good Neighbor SIP or FIP requirements. The EPA cites a single example of certain units in Missouri that had high emissions, triggering the Assurance Level provisions and resulting in the facilities' surrender of additional allowances. While it should not be necessary to disrupt the proven market-based program for a single concern, the EPA's proposal includes a new enforceable ozone season compliance limit. The current Assurance Level provisions are sufficient to address EPA's concern that EGUs should operate the installed NOx controls during the ozone season, particularly given current allowance prices.

The commenter's specific concerns with the Proposed FIP include the "dynamic" process to set future year NOx budgets, setting a limit on banked allowances, imposing penalties for exceeding a daily "backstop" emissions rate, the stringency of the control technology emissions rates used to set the NOx budgets, and adjustments to state NOx budgets based on EPA's concept of intrastate generation shifting.

Commenter (0539) worries that the proposed FIP, as written, may work to push generation from states that are subject to the FIP, such as Minnesota, to states that are not subject to the FIP, such as North Dakota or South Dakota.

Response:

See Preamble Section VI.B.1, including Section VI.B.1.d, for an overall discussion of the changes made in the final rule to increase EGU compliance flexibility while continuing to achieve the Step 3 control stringency for EGUs adopted in the final rule. For discussion of comments regarding the EPA's legal authority, see also Preamble Section III. For discussion of other comments concerning the final rule's enhancements to the Group 3 trading program, see also Preamble Sections VI.B.4 (budgets and budget-setting), VI.B.6 (allowance bank recalibration), VI.B.7 (backstop daily NO_X emissions rate), and VI.B.8 (secondary emissions limitation). Regarding the concern that generation could shift to states outside the Group 3 trading program, the EPA summarizes this potential effect in Table 4-6 of the RIA. Specifically, the final policy evaluation captures emission changes within the 22 covered state

GNP region and in the remaining non-covered states. For 2023, it shows a potential emissions increase of approximately 80 tons (out of 143,000 baseline tons) in those non-covered states. This reflects an increase of less than 0.1% percent. At full implementation of the rule's stringency, the increase is about 1.5% in those non-covered states. The EPA has not observed substantial emissions leakage in prior transport programs, nor does its analysis of this rule suggest substantial increases (but, again, some increases are projected and these are captured in the EPA's analysis and final rule air quality modeling).

The potential for such shifting is to some extent inherent and unavoidable given the nature of the interconnected power grid. We note that the displacement of emissions to regions farther away from interstate-transport receptors, even though not intended, is not inconsistent with the purposes of rules under the good neighbor provision. The fact that this potential exists also highlights the importance of applying a low contribution threshold at Step 2 in order to ensure all upwind states contributing above de minimis levels are brought within the scope of the program.

Comment:

Commenter (0510) supports certain aspects of EPA's proposed transport rule, including new methods to maintain effective budgets and allowance banks and inclusion of non-EGUs. The commenter states that previous versions of the NOx trading rule resulted in a surplus of underpriced NOx allowances that allowed sources to selectively turn off post-combustion controls. The commenter remarks that New York State operates a RACT program that places stringent emissions limits and control requirements on a wide variety of EGU and non-EGU sources. According to the commenter, the EPA's proposed emissions limits for upwind non-EGUs will result in needed NOx emission reductions and will make for a more equitable regional control program by addressing these sources' contributions to downwind areas.

Response:

In regard to commenters assertion that prior EPA trading programs for EGUs have led to oversupplied and underprices allowances that allowed sources to turn off their controls, the EPA directs the commenters to Section VI.B.1 of the preamble where we discuss enhancements to the trading program to preserve the stringency identified as necessary to eliminate significant contribution at Step 3.

5.2.1.12 Generation Shifting

Comments:

Commenter (0372) opposes generation shifting on the grounds that it is divorced from the reality of generation dispatch. The commenter expresses that the generations shifting base case for Kentucky is based on inaccurate data and false assumptions. The commenter explains that the EPA uses the Integrated Planning Model (IPM) of regional breakdowns of net energy for load in each of the 67 IPM U.S. regions for its generation shifting analysis, which contains three IPM runs to reach final results: the Base Case, Run 1 and Run 2. In the State Budget Setting process, generation shifting is the third and final step in determining state budgets. The commenter notes that the base case is the foundation for the entire model, and the base cases examined have multiple flaws. The commenter reported that NRECA, on behalf of its cooperative members, examined the IPM model last year and identified these flaws in a letter to EPA but no corrections were carried through to the dataset used in this proposed rule. The commenter explains that the base case retires or idles units that have no plans for retirements or nonoperation, and this is a significant error, as this capacity is not carried through as viable generation for later runs but are essentially written off for future operation. The commenter remarks that the model projects generation shifted to sources not covered in the proposed rule, such as non-fossil, storage, and industrial facilities, even though many of these eliminated candidates are well-controlled low NOx emitting coal units. The commenter provides a list of units that the EPA erroneously idled, notes one unit where the EPA incorrectly assumed a gas-conversion and lists units for which the IPM uses emissions values that exceed permit limits.

Commenter (0372) states that the generation shifting model assumes the free flow of electricity across states and RTOs and all transmission constrained areas, and the commenter asserts that this assumption does not reflect market reality when there are multiple RTOs and inevitable transmission congested areas. The commenter further states that the model shifts generation outside of the CSAPR program to non-program units such as storage (energy or pump), landfill, reciprocating units, and non-fossil capacity types. According to the commenter, those unit allocations are removed from the state budgets and assumed to be replaced with assets outside of the program. The commenter also remarks that its nine-state analysis yields inconsistent results that would not take place in the marketplace. The commenter notes that the EPA has removed a large number of Kentucky allocations, particularly in 2026, from the state budgets due to this model, and the result is that well-controlled units with SCRs must restrict operations (capacity factors) to comply. The commenter states that it is unclear how the EPA anticipates units with state-of-the-art controls can reduce emissions beyond their technological capacity. The commenter claims that the outcome of the model may be the dispatch of older gas-fired units typically only used as peaking units, which is not an outcome the EPA should force. The commenter also notes that the expected scarcity of allowances coupled with allowance bank restrictions has already caused the allowance costs to bloom, noting that costs have risen from $15,000 per Group 3 allowance on April 28 to over $30,000 per allowance by mid-June. The commenter adds that the cost to “buy back” these tons lost to generation shifting is $15.99 million at June prices.

Commenters (0364, 0363) oppose the strategy of generation shifting, which they say exposes communities to the volatility of market energy and capacity pricing. The commenters add that this will cause uneconomic EGUs to be dispatched, thus increasing market energy costs for other providers, and thus for their customers due to significant rate increases. The commenters express concern that generation shifting assumes the existence of low-NOx-emission EGUs that are available to operate in place of higher-NOx-emission EGUs, which may not be true in all markets. For example, commenters note that “In the Summer 2022 Seasonal Readiness Workshop, MISO projected that available generating capacity (119 GW) would be insufficient to meet the probable peak load in July (124 GW) and August (121 GW).”

Commenter (0372) opposes the use of generation shifting, which commenter states goes beyond past use of the model. The commenter points to *Wisconsin v. EPA*, which found that

EPA's limited use of generation shifting did not alter state budgets, as well as the 2015 Revised CSAPR Update Rule, where generation shifting was limited to "price level consistent with control operation" and "does not factor in generation shifting reduction potential that may be attributable to incremental new builds or incremental retirements." The commenter notes that EPA states that it follows the same approach as prior CSAPR rules and argues that this is not the case.

Commenter (0372) opposes generation shifting on the grounds that cooperatives have limited generation shifting opportunities within their systems. The commenter writes that this approach should not be defined as a "technology" since it cannot be installed and implemented as a unit. The commenter states that this is not an available strategy for EGUs with smaller systems or single-unit ownership, so the only choice these owners have is to reduce unit runtime and seek to buy power to make up for any shortfalls. The commenter explains that cooperatives often cannot generation shift, so their only option to make up shortfalls is to purchase power off the grid, which may not be economically feasible, especially during the ozone season when capacity is diminished.

Commenter (0372) asserts that the generation shifting model fails to account for permit limits on NOx emissions. According to the commenter, the generation shifting model in Kentucky assumes that generation will shift to EKPC's Bluegrass station. However, the commenter notes that Bluegrass Station has a permitted NOx cap of 95 tons/year, and using generation shifting assumptions that add generation and therefore NOx tons to Bluegrass Station would result in a total of 117 NOx tons for the ozone season only. According to the commenter, this scenario underscores the failure of the modeling effort.

Commenter (0557) argues that the EPA uses a generation shifting model that has no relationship to how generation dispatch really works and urges the EPA to eliminate generation shifting. According to the commenter, the EPA's model fails to account for transmission constraints and market behaviors within RTOs. As an example, the commenter says that the EPA proposes to shift generation in some situations to units with permit restrictions that would prohibit the additional shifted runtime.

Commenter (0411) state the FIP is likely to shift generation from states impacted by this FIP to those that are not (in the Group 3 trading program), and EPA has not fully considered these effects.

Furthermore, the commenter (0758) urges, for the reasons discussed above, that EPA remove allowances from the adjusted budget to reflect future generation shifting as a compliance measure at the abatement cost reflecting the full range of selected controls. The commenter notes that it is simply not the case that generation shifting that has already occurred under previous years' budgets would remove this compliance technique from the remaining fleet's compliance toolbox. Accordingly, the commenter recommends that the EPA continue to model any generation shifting that occurs in future years up to the NOx price reflecting the highest cost-per-ton of the controls shaping the budget—especially considering that the availability of low-cost zero-emitting renewable energy will likely increase over the long term.

Commenter (0758) states that this modeling could occur before EPA publishes the preliminary state emissions budgets for the following year on March 1. See 87 Fed. Reg. at 20,117.

According to the commenter, including modeling in future rounds of budget-setting (*i.e.*, beginning in 2023 to establish the budget for 2025) is appropriate because EPA has proposed to provide a 30-day window in which stakeholders may object to the computation. See id. Even if EPA were to decide not to incorporate modeling of generation shifting into every computation of dynamic budgets going forward, the commenter urges the Agency at least to account for generation shifting in establishing the budget for 2026. In that year, there is a greater risk that units that currently lack post-combustion controls will forgo installing and running those controls, if less-expensive generation shifting is available as a compliance option. In subsequent years, the combined effects of the allowance price and the backstop daily emissions limits will likely have already led to retrofits of existing units with post-combustion controls.

Commenter (0758) supports EPA's proposal to account for generation shifting that is likely to occur under budgets that reflect deployment of the controls at a selected cost threshold. In order to ensure that sources actually install and run the controls that EPA has selected at Step 3, EPA must account for the NOx emissions expected to be reduced when EGUs choose to reduce or shift generation instead of installing and running the selected controls. To do so, EPA has historically modeled changes in generation that occur when EGUs face a NOx price equivalent to the cost of abatement through the use of the selected controls. Were EPA not to adjust the budgets to reflect these emissions reductions anticipated to occur through generation shifting, the price of emission credits would likely fall below EPA's chosen cost-effectiveness threshold, and the budgets would fail to achieve their purpose of incentivizing units to install the selected pollution controls. This result would not be consistent with EPA's approach to quantifying the reductions required from these sources by the Good Neighbor provision—*i.e.*, the reductions that can be achieved through the full deployment of the selected controls. Furthermore, it could lead to an inequitable program in which EGUs that have access to lower-cost opportunities to shift generation forgo installing controls while others must do so (or face high allowance costs).

To ensure seamless functioning of the trading program, commenter (0758) recommends that EPA extend the generation-shifting component of the budget-setting process beyond 2024 and make it severable from the other components. Further, to address the potential for excessive compliance flexibility resulting from unaccounted-for opportunities for generation-shifting, EPA should specify in the final rule that, if this component of budget-setting were to be removed, the modified rule would also eliminate the allowance banks, interstate trading, or both. Those program features would no longer be needed to supply additional allowances to accommodate power-sector variability (up to a state's assurance level) if EGUs within that state could instead obtain surplus allowances from shifting generation.

Commenter (0758) states full deployment of the selected control strategy is properly modeled through a NOx price that reflects the cost-effectiveness of the most stringent level of control that EPA has selected for covered EGUs. Here, beginning in 2026, that NOx price should be at least $12,000/ton, which reflects SCR retrofits on NGCC units which, as discussed above, EPA must include in the rule. The EPA acknowledges that it modeled a NOx price of $10,000/ton, which is $1,000/ton below the cost threshold of $11,000/ton associated with EPA's most stringent selected level of control—*i.e.*, retrofitting large coal-fired EGUs with SCR. The

Agency asserts, however, that the results would not change appreciably if it modeled the higher NOx price, since the lower price “did not induce significant amounts of generation shifting.” Yet the amounts of generation-shifting shown are significant even with the artificially low NOx price, notably in 2026, when two regions are projected to reduce coal generation by over 8% relative to the base case, and by 62% in ERCOT. These results underscore the need to incorporate the full quantity of emission reductions resulting from the NOx price reflecting the most stringent level of selected control for covered EGUs.

Commenter (0758) notes even a higher NOx price that reflects the highest-cost technique in the selected control strategy would not, when imposed in the model, result in the full NOx reductions expected to occur through generation shifting because EPA fails to account for generation shifting across the interconnected grid when doing its state budget-setting modeling. As EPA recognized in the CSAPR Update, “[p]ower generators produce a relatively fungible product, electricity, and they operate within an interconnected electricity grid in which electricity generally cannot be stored in large volumes, so generation and use must be balanced in real time.” Generation shifting that occurs in the Integrated Planning Model (and in the real world) will often involve lower- and zero-emitting sources in states other than the state in which the EGU reducing utilization is located because of the interconnected nature of the grid. This is simply the reality of the structure of the grid, and EPA’s analysis of generation shifting must reflect it.

Commenter (0758) adds historically, EPA’s modeling for budget-setting purposes has restricted a source’s opportunities to shift generation to other sources outside the same state not because of any real- world geographic limitations, but to approximate “small amounts” of generation shifting that could occur by the next ozone season. It is not clear why generation shifting, which happens in “real time,” id., should be time-constrained given available clean resources on the grid. Nor is it apparent why, if there is a time constraint, a geographic limitation to in-state generation shifting would reflect that constraint. The EPA does not explain why it has constrained generation shifting to resources within the same state, other than to note that it is a “proxy for the near-term reductions required in 2023 and 2024.” 87 Fed. Reg. at 20,117. And it has already reasonably assumed in its modeling that economic builds of zero- and lower-emitting resources are limited to baseline projected levels in 2023 and 2024. Unless EPA demonstrates that cleaner generation resources are unavailable in the near term, it cannot reasonably limit generation shifting in the model to those generation resources within the same state. Nor can it maintain the arbitrary assumption that the amount of generation shifting available in the near-term is somehow related to state borders. Instead, EPA must evaluate the full measure of generation shifting potential on the grid and incorporate those available reductions into the state budgets.

Commenter (0758) notes that EPA received comments on the proposed Revised CSAPR Update contending that the Agency lacked authority to incorporate generation shifting into the budget- setting process. See 86 Fed. Reg. at 23,096-97. We agree with the Agency’s response to these comments in the final Revised CSAPR Update, citing the longstanding practice of accounting for emission reductions that are expected to occur from generation shifting in past cross-state rules (including the rule upheld by the Supreme Court). See id. Indeed, it would be irrational for the Agency to ignore this real-world compliance technique that, if unaccounted for, could undermine the control strategy that it has identified as eliminating significant contributions to downwind nonattainment or maintenance issues. We also agree with EPA's observation that section 110 does not limit emission-reduction measures to controls deployed solely at individual sources. See id. To the contrary, the provision expressly authorizes the regulation of "any source" and also, more broadly, "any . . . other type of emissions activity within the State." 42 U.S.C. § 7410(a)(2)(D); *see also EME Homer City*, 572 U.S. at 499 (quoting S. Rep. No. 101–228, at 21 (1989), 1990 U.S.C.C.A.N. 3385, 3407). However, we also encourage EPA to make clear that adjusting the emissions budgets in this way accounts for generation shifting that is likely to be undertaken as a compliance measure by sources and that results incidentally from emission limits reflecting source-by-source NOx control techniques.

Commenter (0341) states that EPA's generation shifting model is flawed and generates unrealistic expectations. The commenter criticizes EPA's methodology as failing to correlate to the unit allocations within a state or take into consideration the market availability and transmission constraints of purchased power. The serving region must first serve their own load before providing energy on the open market, and utilities cannot specify a particular unit in a particular state when purchasing power on the open market. The commenter urges EPA to remove generation shifting from the final rule or limit it to an IPM region within a state if it is included.

The commenter adds that the modeled data is inaccurate and unrealistic for Kentucky and taking corrections into account will provide a NOx emission rate equivalent to the emission rate achieved in the 2021 ozone season.

Response:

See Preamble Section V.B.2 for the EPA's response to comments regarding generation shifting mitigation strategies. Response to comments on generation shifting are also reflected in Chapters 1.3.4 and 4.2.1.2 of this document.

Most of the commenters above are expressing concern about projected generation shifting and corresponding emission reductions being codified into state budgets. The EPA notes its preset and dynamic budgets do not rely on projected generation shifting in the final rule. The EPA does capture EGU fleet expected generation shifting in its baseline, consistent with historical trends and fleet behavior, in order to not overstate the EGU emissions inventory for purposes of making Step 1 and Step 2 determinations. The resulting geographic findings were further affirmed by the Engineering Analysis which assumed fleet operation did not further change and continued to operate as it did in recent historical years (factoring in announced new builds and retirements) Although EPA's finalized EGU emission inventories, utilizing IPM, are developed using an established power sector model that respects NERC regions, target reserve margins, and transmission constraints and are the best representation of expected future conditions, EPA notes that its sensitivity analysis assuming no generation shifting (per the commenter suggestion) does not result in any geographic coverage implications for the rule (i.e., no upwind states would change status under this sensitivity analysis).

5.2.1.13 Unit-specific data

Comments:

Commenter (0290) notes that the EPA used data provided to EIA for retirement dates. The commenter explains that they submitted information to EIA that Braunig Units 1, 2, and 3 may be retired in 2024, and therefore, there are no allocations for these units starting in 2025 in the proposed CSAPR. The commenter notes that the preliminary retirement date of 2024 for these units is not regulatory-driven and therefore are only target dates. The commenter requests that the EPA include these units in the final rule and treat them as if they do not have a retirement date by issuing allowances to these units beyond 2024.

Commenter (0323) states that, in reviewing the unit information with owners, their Project Team identified incorrect technology inventory data that need to be addressed in determining final state budgets. Table 19 (Technology Assignment Issues in the Nine State Study Area) of the commenter's letter presents examples of EPA's errors in the technology inventory that they identified.

Commenter (0409) states that state budgets are riddled with unit-specific errors in the base case and erroneous assumptions for future years because: the base case contains emission rate and retirement date errors; the base case assigns the wrong NOx technology to certain units; the base case identifies incorrect unit capacities; the base case capacity factors cannot be reproduced and may be in error. The commenter also notes state budget assumptions for future years (2026 and beyond) are unworkable in terms of timeline. The commenter (0409) notes that all of the errors we were able to discover during this comment period are reflected in the Technical Report commissioned by NRECA, the Midwest Ozone Group and the American Public Power Association submitted with these NRECA comments to analyze EPA's technical analysis and methodologies used in the Proposed FIP. However, the commenter suggests that, given the limited time for commenting, other errors may exist in state budgets and otherwise. The commenter urges EPA to make corrections and perform an extensive quality assurance review of all state budget data.

The commenter (0409) identifies the following categories of errors in the Base Case:

Base Case Contains Retirement Date Errors. Some units are assumed to retire earlier than planned. Some units are assumed to be retired in 2023 and have no allocations in the state budgets at all. The result is lower state budgets because the units were removed mistakenly.

Base Case Assigns the Wrong NOx Technology to Certain Units. Some on-the- books controls are not accurate in the inventory. Units are assumed to have functional SCRs when these units do not. The units are then assigned a lower NOx rate assumption earlier than is achievable.

Base Case Identifies Incorrect Unit Capacities. The budgets assign net capacities to some units and gross generation to others. The EPA relies on the unit capacities to compare against the Proposed Rule's thresholds, such as the threshold for oil/gas SCR retrofits. The unit capacities should follow an accurate and consistent approach.

Base Case Capacity Factors Cannot be Reproduced and May be in Error. The flawed and inconsistent unit capacities are likely the cause of our inability to reproduce the unit capacity factors EPA devised. We were unable to confirm the 2021 unit capacity factors are accurate based on what is in the rulemaking record.

Commenter (0275) requests revision of budget for its specific unit because it is well-controlled (with an integrated multipollutant control technology (ReACT or "Regenerative Activated Coke Technology") and adding an SCR would not result in significant additional NOx reductions, nor is not cost effective. Specifically, the commenter requests that the EPA revise the Wisconsin NOx Allowance budget upward to include the additional 28 tons of allowances that were erroneously projected to be generated by installing additional NOx controls on Wisconsin Public Service Corporation's Weston Unit 3.

Commenters (0330, 0500) found errors within the spreadsheet entitled "unit-level-allocations-and-underlying-data-for-the-proposed-rule.xlsx", in the "Underlying Data for FIP" worksheet. Commenter (0330) notes they identified some minor inconsistencies in the 2021 data for the Grayling Generating Station, Unit 1, a CMS Enterprise asset. Specifically, the listed 2021 ozone season heat input for the unit is 1,573,787 mmBtu. However, per the ECMPS Feedback Report, the 2021 ozone season heat input was 1,575,169 mmBtu. This error may have a slight effect on the 2023 and 2024 allocations for units within Michigan. Commenter (0500) says Alabama Power Company ("APC") is currently constructing a new combined-cycle unit at Plant James M. Barry [ORIS Plant Code: 3] ("Plant Barry Unit 8"). The spreadsheet does not include Plant Barry Unit 8 on its "New Units" tab. Plant Barry Unit 8 is scheduled to start commercial operations by November 2023. Because this unit did not commence commercial operation until after January 1, 2021, but the Agency is aware of its construction and need for allocations, the commenters stresses Plant Barry Unit 8 should be added to the "New Units" tab of the spreadsheet.

The commenter (0409) identifies the following categories of errors in the Base Case:

Base Case Emission Rate Errors. There are incorrect assumptions as to NOx emission rates for SCR and non-SCR units sharing a common stack. NOx emission rates were not accurate with respect to natural gas conversions.

Commenter (0323) states that the EPA's Budget Setting Process did not accurately assign NOx emission rates to SCR and non-SCR units sharing a common stack. Table 16 (2021 Unit Emission SCR Emission Rates (lbs/mmBtu) of the commenter's letter lists those SCR-equipped units in both Indiana and Kentucky that share a common stack with non-SCR-equipped units, as determined from discussions with unit operators. The commenter (0323) notes that correcting NOx emissions from the SCR–equipped unit to a lower value increases the NOx tons assigned to the non-SCR-equipped unit, as total common stack emissions must remain the same. They explain that, if the non-SCR-equipped unit is equipped with state-of-the-art combustion controls, any such revision of assigned NOx tons increases the budget for 2024 and forward years. They add that, if the non-SCR- equipped unit does not have state-of-the-art combustion controls, the 2024 and forward emissions are adjusted based upon retrofitting the unit with a state-of-the-art emission factor.

Response:

See file titled "Unit Specific Comment Log" in the Docket for this Action for a record of unit-specific changes EPA made to its analysis in response to comment. For a response to comment on treatment of shared stack emission in the Engineering Analysis, see response to comment in section 4.2.1.4.

5.3 Regulatory Requirements for Non-EGUs

Comments:

Commenter (0300) observes that 52.43(e)(1)(ii) and (iii) and 52.45(f)(2)(ii) and (iii) indicate NO_X emissions could be "predicted," which may be an error in the language.

Response:

The final rule includes alternatives to CEMS monitoring for Iron and Steel units under 52.43 and Boilers under 52.45. The regulatory text correctly uses "predicted" since CEMS will not always be used and parametric monitoring will be used to predict emissions and ensure continuous compliance. For further discussion see preamble Section VI.C, VI.C.3, and VI.C.6.

Comments:

Commenter (0301) suggests that the proposed FIP regulations pertaining to non-EGUs, codified as 40 CFR 52.40 through 52.45, appear to contain substantial omissions, errors, and ambiguities, including the following:

- General recordkeeping requirements in 40 CFR 52.40(b)(3) appear to be inconsistent with recordkeeping requirements elsewhere in the rule.
- There is more direction and specificity dedicated to reporting to Compliance and Emissions Data Reporting Interface (CEDRI) than there is to actual regulatory requirements specific to the industrial sector. CEDRI reporting requirements should be consolidated in one location that can be referred to rather than repeated throughout each section.

Response:

The CEDRI recordkeeping requirements have been moved to 40 CFR § 52.40(c)(3) and all recordkeeping provisions in §§ 52.41 through 52.46 refer back to § 52.40(c)(3). Section VI.C of the preamble provides additional discussion of the final provisions related to recordkeeping and CEDRI.

Comment:

Commenter (0300) observes that regulations do not appear to define, or otherwise address, what constitutes a *new or existing emissions unit* for each regulated industrial category.

Response:

The final rule regulatory text defines new and existing facilities. For purposes of this final rule, consistent with the proposal, both new and existing facilities are subject to the final FIP requirements. *See* Section III.B.1.d of the preamble.

Comments:

Commenter (0501,0397) Change cross-reference in "listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s)" to § 52.40(b)(2).

Response:

The final rule regulatory text includes these corrections.

Comment:

Commenter (0300) observes that 40 CFR 52.42(b) and 40 CFR 52.43(b) uses the term *"potential to emit,"* 40 CFR 52.43(e)(1)(iii) refers to "*steam generating unit operating days,*" and 40 CFR 52.45(a) refers to "*boiler,*" without defining them

Response:

The final rule regulatory text defines these terms.

Support for Controls for Non-EGUs

Comments:

Commenters (0257, 0259, 0402, 0558) support the EPA's decision to look beyond the power sector to additional controls on NO_X emissions from non-fossil fuel-fired EGUs, including reciprocating internal combustion engines in Pipeline transportation to Natural Gas; kilns in Cement and Cement Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and high-emitting, large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. Commenters (0257, 0259, 0402) believe these additional industries are contributing to ozone harms in Tribal communities and support the additional requirements on these industries in the proposed rule.

Commenter (0379) responds to the EPA's request for comment on non-EGU control strategies and measures by noting that NO_X is a widespread year-round pollutant on its own, in addition to being a precursor to seasonal ozone, and has adverse public health impacts. The commenter strongly recommends requiring adaptation and running of optimal emissions controls on ICI boilers and reciprocating internal combustion engines all through the year to protect public health.

Response:

These comments provide general support for this action and do not require a specific response. The EPA has addressed each of the commenters' specific comments in the preamble, this RTC document, or other support materials.

Case-by-Case Limits or Exemptions

Comments:

Commenter (0377) states the EPA purportedly developed the emissions limit of 4 pounds of NO_X per ton of glass pulled for pressed/blown glass manufacturing furnaces based on a review of Reasonably Available Control Technology (RACT) from multiple states. The EPA acknowledged that most of the states in the OTR that implement RACT regulations for the glass manufacturing industry do not specify presumptive NO_X limits. Instead, the EPA noted that such states rely upon a case-by-case analysis. Yet the EPA did not include a case- by-case analysis option in the proposed rule.

Commenter (0377) asserts that it is imperative that the EPA include a case-by-case analysis provision in the proposed rule to allow glass manufacturing companies to demonstrate that compliance with the emissions limit (whether achieved through add-on control technology or otherwise) is not technically feasible or economically reasonable. This is necessary due to the unique furnace configurations across the industry. What is feasible for one furnace may not be feasible for another furnace. The use of a case-by-case analysis in rulemaking is a standard approach to ensure the rule fairly identifies site-specific circumstances. In particular, as noted by the EPA, case-by-case analyses are standard in RACT rulemakings. See, *e.g.*, Ohio Admin. Code 3745-21-11 (Reasonably available control technology studies for non-CTG sources in ozone nonattainment areas); 25 Pa. Code § 129.114 (Alternative RACT proposal and petition for alternative compliance schedule). Due to the prevalence of such flexibility terms, commenter (0377) asserts that the EPA should include a case-by-case term in the rule to address the need for flexibility on technical or economic feasibility which is common practice in similar NO_X control rulemakings.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

CEMS Requirements

Comments:

Commenters (0266, 0344, 0353) recommend that the EPA consider the costs associated with deployment and ongoing operation of CEMS when performing the cost-benefit analysis and should take into consideration the marginal cost threshold under the EPA's screening analysis. The commenters say that CEMS are expensive to procure and install, and ongoing operation requires specialized technical staff that many non-EGU sources have never considered using.

Commenters (0266, 0344) recommend that the EPA not require CEMS across the board for all categories or even for just some categories. Rather, the commenters state that the EPA should consider only requiring CEMS for the most significant emitters of NO_X. For example, commenter (0266) proposes actual emissions greater than 1,000 tpy. Commenter (0344) recommends CEMS only be required for sources that have an individual impact greater than one part per billion (1 PPB) at a problem receptor.

Commenter (0266) mentions that under the NO_X SIP Call, the EPA provided a mechanism to allow sources that had long been operating CEMS to request an alternative monitoring mechanism. According to the commenter, many sources have stopped using CEMS and have implemented their approved alternative, but some of these sources may find themselves now subject to this new transport FIP and the requirement for CEMS. The commenter recommends that the EPA consider grandfathering alternative approvals and allow these sources to be eligible for alternative monitoring under this FIP.

Commenter (0557) supports consideration of other monitoring options over CEMS, such as predictive emissions monitoring systems (PEMS), which have been accepted in other emissions monitoring contexts.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

General Monitoring Requirements

Comments:

Commenter (0300) observes that 40 CFR 52.42(d)(1) and 40 CFR 52.44(d) do not specify the date by which the initial performance test must be conducted but only refer to conducting testing on a semiannual basis.

Response:

The final rule regulatory text specifies when an initial performance test must be conducted to establish indicator ranges for parametric monitoring.

Comments:

Commenter (0336) adds that the proposed rule makes it clear that the proposed standards only apply during the ozone season. The commenter opines that in situations where the EPA determines that compliance should be determined by performance testing rather than CEMS data, performance testing once per ozone season may make more sense than requiring testing every six months, due to the length of the ozone season (five months).

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

Comments:

Commenter (0359) requests that industrial sources subject to both the FIP and the NO_X SIP Call requirements be allowed the opportunity to demonstrate compliance with streamlined reporting rather than be subject to duplicative requirements, which according to the commenter, will also create unnecessary paperwork for state and regional EPA staff and requires the use of scarce state resources for no environmental gain.

Response:

The EPA anticipates that sources will be able to work with their permitting authorities to develop reasonable approaches to complying with their monitoring, recordkeeping, and reporting requirements for NO_X limits in this final rule in conjunction with their preexisting requirements under the CAA. The EPA disagrees that the final rule can "streamline" the reporting requirements of this rule with those of the NO_X SIP Call. Due to the stringency of the emissions limits in the final rule and the need for initial notifications, emissions averaging plans, and other reporting requirements to determine compliance unique to the final rule, and the fact that each state subject to the SIP Call has developed their own provisions to implement the requirements of 40 CFR 51.121, the EPA does not believe it would be appropriate to attempt to merge the reporting requirements of the NO_X SIP Call with this final rule.

Flexibility and Exemptions

Comments:

Commenter (0798) states for non-EGUs, the proposed rule arbitrarily includes no flexibility at all. According to the commenter, there is no allowance for variances from the EPA's "command-and-control" emissions limits for facilities that cannot retrofit to use the required pollution control equipment or achieve the reductions the proposed rule prescribes even after installing the EPA's selected technology. The commenter states that there is no process for submitting an alternative control strategy to the EPA or for non-EGUs or the states in which they are located, to offset the emissions reductions mandated by the proposed rule with other, more cost-effective emissions reductions. The commenter adds that there is not even an opportunity to extend deadlines if it is found that the required pollution control and monitoring equipment required by the proposed rule cannot be purchased and installed on the schedule mandated by the EPA.

Commenter (0379) addresses the EPA's request for comment on the specific criteria that the EPA should apply in evaluating requests for extension of the 2026 compliance deadline for non-EGU sources by urging the EPA to require the installation, adaptation, and optimal running of emissions control technologies starting in the 2023 ozone season for all non-EGU sources covered in this proposed regulation. The commenter does not foresee any scenario where a major for-profit industry (non-EGU source) would be unable to comply with emissions control requirements in one year with an emissions standard promulgated seven years earlier and therefore urges the EPA to provide flexibility in the compliance deadline only for valid reasons.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

Comments:

Commenter (0360) proposes that any further reduction in NO_X limits be applicable on a rolling average basis of 12 months or more. The commenter asserts that any averaging period less than 12-months will unnecessarily force operators to run furnaces in a fuel-rich environment to avoid short spikes in NO_X concentrations, which will unnecessarily result in higher CO emissions.

Response:

The EPA disagrees with the claim that a 12-month rolling average limit would be appropriate to assure compliance with limits in the final rule. The EPA has clarified in the final rule that the emissions limits only apply during the 5-month ozone season and a 12-month rolling average limit would not assure compliance with these limits that only apply part of the year. The final rule generally establishes 30-day rolling average emissions limits for all non-EGU categories, which is consistent with state RACT, NSPS, and NESHAP reviewed by the EPA. The EPA finds that 30-day rolling average limits provide reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production. The EPA notes that the final rule does contain a 24-hr limit for MWCs that is slightly less restrictive than the 30-day rolling average limit. The basis for these limits and the selected averaging times for all non-EGU requirements are discussed further in the preamble at Sections VI.C.1-6 and in the Final Non-EGU Sectors TSD.

Comments:

Commenter (0336) asserts that the EPA should address situations in the final regulation for each non-EGU category where state operating permits or other federally enforceable instruments could be used to avoid being subject to the rule, such as limits to the PTE or limits on the fuels used. The commenter urges that if the EPA concludes that these are valid approaches to avoid applicability, then the regulatory language should clarify that intent. Conversely, the commenter argues that if the EPA will be considering applicability based on past operations and limitations, then this should also be clarified in the regulatory language.

Commenter (0422) submits that the EPA should include an applicability threshold based on PTE and alternatively recommends including an option for taking a federally enforceable limit to maintain actual emissions of NO_X per boiler below that threshold limit. The commenter says this will provide additional compliance options for non-EGU's while ensuring NO_X emissions stay low.

Commenters (0266, 0387) are concerned that due to a lack of clarity in definition and applicability, some sources may falsely be assuming they are not subject to the FIP and may not review and comment on the proposal. The commenter (0266) notes that applicability for many non-EGUs is based upon a calculation of potential-to-emit (PTE), however, there is no definition in the proposed FIP. According to the commenter, the EPA relies on all the definitions of subpart A of part 60, which does not contain a definition for PTE. The commenter requests that the EPA provide additional clarity on how PTE is defined and calculated and recommends that the EPA clarify whether PTE calculations should follow new source review program rules, reasonably available control technology SIP program rules, or some other definition.

Commenters (0287, 0504,) argue the EPA should amend the regulatory language to explicitly state that an owner/operator of a new or existing emissions unit can rely on federally enforceable permit conditions to ensure that the unit's PTE remains below 100 TPY, thus excluding the emissions unit from the proposed FIP's applicability. Commenters (0287, 0504) continue, in response to a question during the Agency's Informational Stakeholder Webinars on March 29-31, 2022, the EPA personnel noted that, while the proposed FIP does not expressly state that owners/operators can manage PTE in this way, the ability to potentially use enforceable permit conditions was implied based on the EPA's longstanding approach to PTE in other contexts. Commenters (0287, 0504) agree with this view and urge the Agency to provide regulatory text memorializing this approach if the EPA ultimately promulgates the proposed FIP or a similar regulatory action.

Commenter (0405) states the iron and steel sector applicability should be based on a higher ton per year threshold. The EPA is imposing mandates on emissions units in the Iron and Steel sector that are smaller from an emissions standpoint than EGUs. To ensure that the rule does not arbitrarily impose obligations on smaller sources, and to ensure uniformity across industries, Cliffs requests that the EPA set the applicability threshold for individual emissions units in the Iron and Steel sector to at least 150 tons of NO_X per year PTE. The commenter also quotes the preamble and the proposed rule and notes there is an inconsistency on aggregation of affected units.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

Comments:

Commenter (0289) encourages the EPA to consider more flexible compliance options for the non-EGU industries included in the proposed FIP. The commenter suggests that similar to the trading program for EGU sources, the EPA could evaluate whether facility-wide average emissions rates are an acceptable compliance option. According to the commenter, this is especially the case where one or two units run continuously during the ozone season, but several other units subject to the rule may rarely run during the ozone season. The commenter believes this would be a far more cost-effective strategy than the command-and-control approach proposed in the FIP for these types of facilities, yet it would still achieve a vast majority of the emissions reductions intended by the proposed FIP.

Commenter (0353) remarks that emergency stationary engines should be exempt from the FIP. The commenter states that the EPA has traditionally exempted emergency engines or set more lenient emissions standards for them because the EPA has typically found that the use of add-on emissions controls cannot be justified based on cost effectiveness. The commenter notes that neither the proposed rule nor the major supporting documents in the rulemaking docket provide any consideration of whether the same proposed NO_X emissions limits are appropriate for emergency uses. The commenter believes this is a significant omission, as the EPA has previously stated that the Agency's policy is to maintain consistent regulations for emergency engines across CAA programs.

Commenters (0266, 0344, 0353, 0336) state that the proposed rule would require performance testing every six months and also require monitoring and recording of various operating parameters, such as fuel consumption, air-to-fuel ratio, inlet temperature, and pressure drop across any catalyst used. According to the commenters, these compliance requirements are expensive, burdensome, and unnecessary. Further, the commenters state that the proposed rule and supporting materials provide no explanation as to why the EPA is proposing these particular compliance requirements.

Commenter (0501) requests that the definition of an *"affected unit"* be amended to clarify that emergency engines are not included in the Proposed Rule's requirements. The commenter briefly discusses how the vast majority of emergency engines are not likely to have emissions in significant amounts due to their limited hours of operation and are regulated by to other, more appropriate programs.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble.

NAICS Codes

Comments:

Commenters (0336, 0557) recommend that the EPA make each applicability section within the non-EGU portions of the FIP as specific as possible. For example, the commenter remarks that if controls are expected to be applied to units with a specific NAICS, that NAICS should be listed in the regulation, or if the facility or unit should have a PTE of at least 100 tpy of NO_X, then that threshold should be included. The commenter states that the EPA should not rely on information in technical support documents or other data sources for applicability criteria but should specifically list criterion in the regulation. Commenter (0557) adds it is unclear whether the NAICS codes determine applicability or are used as a general guideline to alert industry sectors to potential coverage. Specifically, the commenter states that if an emissions unit addressed in the proposal is located at a facility with a NAICS code not identified in the rule, the EPA should clarify that the emissions unit is not subject to the FIP.

Commenter (0417) is providing limited comments on the applicability provisions regarding the non-EGU facilities proposed in this rule. Under the EPA's proposed rule, certain unit types at the identified non-EGU industries are subject to emissions limitations in the covered states. 87 Fed. Reg. at 20,041. Included in this list are "high-emitting equipment and large boilers in Basic Chemical Manufacturing." Id. The EPA utilizes the NAICS codes to further identify the regulated industry group, with the Basic Chemical Manufacturing group covering NAICS code 3251. Id. at 20049- 50. Other industries include Cement and Concrete Product Manufacturing, Glass and Glass Product Manufacturing, Iron and Steel Mills and Ferroalloy Manufacturing, and Pulp, Paper, and Paperboard Mills. Id.

Commenter (0417) has concerns regarding the EPA's use of the four-digit NAICS code as the sole regulatory language for identifying units that are subject to the emissions limitations in the covered states. While the four-digit NAICS code can help identify industries at a high level, there is potential for confusion and determinations of applicability that are inconsistent with the EPA's intention. This potential stems from the fact that while the NAICS system attempts to be uniform, the code is often self-determined and more than one code can apply to an establishment. Indeed, the FAQ section on the U.S. Census Bureau directs individuals to determine the NAICS code for their business by searching for the primary business activity and choosing the NAICS code that most closely corresponds to their primary business activity. The U.S. Census Bureau also recognizes that there may be a lack of uniformity between agencies and the codes assigned, noting that "[i]ndividual establishments are assigned NAICS codes by various agencies for various purposes using a variety of methods." As a result, facilities may have more than one NAICS code that it uses for different purposes or may have changed NAICS codes as the codes were updated.

Response:

With regard to commenters request for further defined applicability criteria, the EPA has made multiple updates to the applicability criteria for all non-EGU industries to better identify the correct types of units that will be subject to the final rule. These changes and the reasoning for them are further discussed in the preamble in Section VI.C.

With regard to the commenters concerns regarding the rules use of NAICS codes in the preamble, the EPA does not agree with some commenters' general comments that the EPA's use of NAICS codes in the preamble were inappropriate. The EPA has a historic practice in all our NSPS, NESHAPs, and CAA § 110 rulemakings of identifying the potentially affected industries by NAICS code in the preamble only. The EPA uses the NAICS codes in the preamble only to assist industry and the public and identifying the types of industry that may be subject to the rulemaking but has always maintained that sources will need to review the regulatory text itself to determine if their units are subject to the rule. The EPA has never included a NAICS code in the regulatory text itself because that would unnecessarily restrict the regulation. As identified by other commenters, if the NAICS code were updated, the EPA's regulations could potentially no longer apply to correct units, which would undermine the purpose of the rulemaking. Further, sources that mischaracterize their appropriate NAICS code might potentially be unaware that the regulation applied to them since the applicability criteria would be based on NAICS codes alone. In this rulemaking, the NAICS codes identified in the preamble are only meant to provide the public with an idea of what industries might be affected and should not be relied on as a definitive statement of whether or not a particular unit is subject to the final rule.

<u>Miscellaneous</u>

Comments:

Commenter (0398) state this back-of-the-napkin estimation also resulted in gross under accounting of emissions reductions. In one example presented to DEQ by the steel industry in

Arkansas during stakeholder outreach, the EPA estimated a six-ton reduction in emissions, when in fact, installing controls required by the EPA's proposed FIP at Arkansas's steel industrial sites would yield a few hundred tons of emissions reductions. In Arkansas especially, a state with "linkages" to a single other state in amounts that rank very near the cutoff point that would result in no requirement to consider additional source emissions controls, this extreme underestimation results in gross over-control of Arkansas's sources. This is but a single instance from one non-EGU industry sector. Moreover, most of the iron and steel sector sources that the EPA linked to downwind receptors are integrated steel facilities that use blast and BOFs. But the steel industry in Arkansas operates electric arc furnaces (EAFs) that produce steel from scrap. EAF producers have different operations, equipment and emissions profiles than integrated steel facilities. Because of these differences, the EPA's control technology determination for EAFs is not supported. It is apparent to DEQ through initial review of the EPA's proposed FIP that if given time to *thoroughly* analyze the datasets and assumptions made by the EPA for all sectors, that likely errors such as this could be discovered and corrected by states. States are far better situated to perform a robust and directed analysis of state emissions sources, and further analysis would certainly produce more realistic expected results. Additionally, if the EPA only includes emissions reductions from sources emitting greater than100tpy NO_X in its air quality analysis, the EPA must match its applicability criteria for sources for inclusion in a finalized FIP, rather than using surrogates (such as lb/MMBtu, and lb/ton Clinker, etc.).

Response:

The commenters concerns related to the applicability thresholds for non-EGUs are addressed in the preamble in Section VI.C, which explains the basis for the applicability thresholds in the final rule. With regard to the commenter's concerns regarding EAFs, blast furnaces, and BOFs in the Iron and Steel sector, the final rule does not include emissions limits that apply to these units. For discussion of the basis for the EPA's decision not to finalize many of the proposed emissions limits for Iron and Steel, see the preamble in Section VI.C.3.

Non-EGUs Should Be Allowed to Opt into the Trading Program

Comments:

Commenters (0338, 0437) write that non-EGUs should be allowed to opt into the EGU trading program so that industrial sources can obtain emissions reductions in a more "cost-effective manner." Commenter (0437) adds that alternatively, the EPA could allow non-EGUs to use a general account to purchase and retire ozone season NO_X tons to make up for any deficit between a boiler's actual performance and the non-EGU ozone season emissions limit. Commenter (0437) adds that if pulp and paper mills generate NO_X credits, as they have done in the original NO_X SIP call, they should be able to sell them to any entity that is covered by the final rule.

Commenter (0421) further writes that the EPA should consider including the NO_X emissions associated with industrial boilers as eligible emissions allowances that could be part of the EGU trading program. For example, a natural gas fueled boiler with a heat input of 300

MMBtu/hr that emits NO_X at 0.08 lbs/MMBtu, could have NO_X emissions of approximately 24 lbs/hr or 44.06 tpy (3,672 hours of ozone season) of NO_X during the ozone season and comply with the proposed CSAPR rule for industrial boilers. If the actual NO_X emissions from the boiler are lower than the allowable limit during the ozone season, then any available NO_X emissions allowances should be allowed to be traded with an EGU source to demonstrate compliance with the limit(s) for the EGU source. Alternatively, commenter suggests that if the EGU source has some emissions allowances for NO_X during the ozone season, they should be allowed to trade them with the industrial boiler to demonstrate compliance.

Commenter (0516) states that forbidding industrial sources from participating in the trading program is arbitrary and capricious. The commenter explains that the EPA's rationale for not including non-EGUs in the trading program is because it would require monitoring and reporting of hourly mass emissions, including the use of CEMS, rigorous initial certification testing, and periodic quality assurance testing, such as relative accuracy test audits ("RATA"). The commenter proposes that non-EGU facilities be allowed to opt-in to the trading program. The commenter notes that many cement industry facilities already fulfill all the criteria that the EPA has outlined to be eligible for emissions trading under CSAPR. The commenter states that it was the EPA's apparent rush to issue the proposed rule that prevented the EPA from collecting facility data and establishing a baseline so that facilities could participate in an emissions trading program. The commenter states that as the EPA works with industry in determining feasible NO_X emissions reductions, it should fully evaluate the industry's monitoring of NO_X emissions and allow for facilities that continuously monitor their NO_X emissions to be allowed to participate in an emissions trading program under CSAPR.

Commenters (0320, 0324, 0424, 0513, 0530, 0541, 0545, 0549, 0758, 0798) believe the EPA should finalize regulatory language that allows non-EGUs with NO_X CEMS to opt into the ozone season NO_X trading program. According to the commenters, the EPA has proposed to apply controls on boilers where it will be much more expensive than $7,500/ton to apply them. If the EPA retains the proposed regulatory requirements for non-EGUs and does not allow for site-specific cost effectiveness analyses to avoid application of costly or potentially infeasible NO_X controls, the commenters state that it should allow non-EGUs the flexibility to manage their emissions in a more cost-effective manner, which may include NO_X reduction methods that are less stringent than proposed by the EPA, and the purchase of NO_X allowances available in the current EGU trading program. According to the commenters, a more flexible program would not only reduce direct costs of installing and operating control systems but could also avoid additional waste generation.

Commenters (0513, 0541) state that opt-in allocations for non-EGUs would also benefit EGU sources by increasing the number of allocations in circulation, alleviating some of the inflexibility inherent with the currently proposed trading program. The commenters state that allowing non-EGU sources to opt in would provide the same NO_X reductions as a rate limit but with the added benefit of incentivizing electrification and providing for increased trading.

Commenter (0798) states that the EPA's decision to exclude all non-EGU's from the emissions trading program is a major regulatory about-face by the agency which it neither recognizes nor confronts, impermissibly attempting to "depart from a prior policy sub silentio." See FCC v. Fox TV Stations, Inc., 556 U.S. 502, 515 (2009). According to the commenter, the EPA has consistently endorsed an emissions trading program over unit-specific limitations, and the Proposal fails to adequately justify the decision to categorically exclude non- EGUs from the trading program. The commenter continues that the EPA proposes to exclude non-EGUs from the trading program and seeks to justify this exclusion by asserting that if it were to include non-EGUs in the trading program, it would require monitoring and reporting of hourly mass emissions as it has for all trading programs and that applying unit-level emissions limitations rather than constructing an emissions trading regime is more administratively feasible and more easily implementable at the source level. The commenter states that this proposed exclusion is arbitrary and capricious for a number of reasons, including that the proposed rule already requires the installation of monitoring equipment for non- EGUs. The commenter adds that when the EPA initiated the trading program, it provided EGUs with no less than two-and-a-half years to install monitoring equipment, but that the EPA now appears to believe that three-and-a-half years (until the compliance deadline of 2026) is an inadequate amount of time, warranting the exclusion of non-EGUs from the trading program. The commenter states that the EPA does not provide any reason for this shift other than to note general uncertainty as to how long it may take non-EGUs to install monitoring equipment. The commenter states that the EPA's failure to justify its "depart[ure] from a prior policy" renders the decision to exclude non-EGUs from the trading program "arbitrary and capricious." The commenter adds that the EPA's assertion that it has "require[d] monitoring . . . for all trading programs," ignores that when the EPA initiated the trading program, the provision requiring use of CEMS still provided a process for a "unit that does not meet the applicable compliance date" for installing monitoring equipment to "determine, record, and report substitute data" in lieu of CEMS data. The commenter states that the EPA should likewise provide a process for providing "substitute data" in the event that certain units are unable to install monitoring equipment by 2026 or confront and justify its decision to deny non-EGUs this ability provided to EGUs. Further the commenter states the assertion that unit level controls are superior for non-EGUs because they are "more administratively feasible and more easily implementable at the source level" is fatally inconsistent not just with the EPA's prior findings, but with the proposed rule itself, which elsewhere expressly finds that an emissions trading program is superior to direct controls for EGUs.

Response:

The EPA's authority to establish unit- or source-specific emissions rates is addressed in Section IV.B.1 of the preamble. The basis for the EPA's decision to not include non-EGUs in the trading program is contained in Section VI.C of the preamble.

5.3.1 Pipeline Transportation for Natural Gas

Comments:

Commenters (0314, 0501) argue that the rule requires unnecessary emissions controls on components of the interstate natural gas pipeline system and petroleum refineries.

Commenter (0350) expresses concern that the proposed rule would impact roughly 950 units; adding that a large-scale reduction in output of natural gas is unavoidable. The commenter explains that the number of available manufactures capable of retrofitting units is limited, along with expert labor – likely to create a backlog of services, materials, equipment, etc., resulting in engines having to remain offline for extended periods of time, which could potentially jeopardize the safe and reliable transmission of natural gas (periodic outages) along in the United States and/or could lead to higher costs for transporting gas. The commenter adds that these costs will ultimately be passed along to customers, often residing in low-income, communities of color. More specifically, the commenter states 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, and often face greater impacts to health and wellbeing. The commenter cites a 2019 study found titled, "Energy Cost Burdens for Low-Income and Minority Households," that shows that low-income households in U.S. cities spend on average 10–20 percent of their income on energy bills.

Commenter (0501) states that the installation of controls and monitoring equipment (to meet the EPA's proposed schedule) will require taking affected units offline for extended periods of time and expresses their concern this will result in serious reliability implications particularly on interstate natural gas pipeline companies that operate as an interconnected system. The commenter states that the EPA has not assessed (*e.g.,* no technical support documents or substantive analysis) how interconnected systems will be impacted, nor has the Agency offered any guidance on how such a massive effort could be coordinated and implies that the 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 commenter warns of a reduction in our nation's energy throughput; explaining that each pipeline will need to take their affected units offline at the same time to meet the EPA's compliance deadline, because the time needed to complete the necessary retrofits would preclude an orderly, sequential approach. The commenter adds that the US natural gas pipeline system is a highly integrated network, and further explains that 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. As an example, the commenter notes that the pipelines delivering natural gas into New England run through New York and New Jersey—two states covered by the EPA's proposal and warns that the removal of RICE units in those states could reduce capacity delivered into New England, causing significant disruptions in the area. The commenter implies that having an interconnected system makes it difficult for pipeline companies to coordinate repair schedules, and the commenter expects to see, as a result, large volumes of capacity reduced at the same time period, as these companies work meet the EPA's compliance deadline. The commenter also expects that these periods (of loss capacity) will likely extend over times of "peak" demand, either during winter or summer months when natural gas utilities and electric generators (*i.e.,* pipeline shippers) need natural gas service to provide heat or air conditioning for their customers. The commenter explains that during these peak periods, pipelines operate at full capacity and need all of their compressor units available to run. The commenter warns that removing multiple units from service during these high demand periods (as well as non-peak periods) will inevitably lead to reliability issues.

Commenter (0380) expresses their concern that 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; further arguing that the 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 commenter insists that the EPA evaluate reliability concerns and tailor the rule to prevent serious and predictable reliability problems. The commenter briefly described the challenges faced (reliability issues) when requiring extensive changes to the natural gas transmission system, within a condense timeframe. The commenter explains that, first, 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. The commenter further explains that these system-wide unit outages, in turn, leave the pipeline (which operate as part of an interconnected system) vulnerable to unexpected engine malfunctions or sudden spikes in demand. The commenter warns that other pipelines connecting to that system will be undergoing the same capacity constraints due to the need to retrofit their own engines; adding that 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. The commenter further alerts that 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.

Response:

The commenters' concerns related to the timing of control installation are addressed in Section VI.A.2 of the preamble. This section of the preamble explains that the final FIPs require compliance with the emissions control requirements by the beginning of the 2026 ozone season, with limited exceptions based on a showing of necessity for individual sources that meet specific criteria. As discussed in Section VI.C.1 of the preamble, Pipeline Transportation of Natural Gas, the EPA has revised its estimate of the number of affected engines, has revised the rule to affect fewer engines by excluding emergency engines and is requiring controls on fewer engines by allowing facility-wide emissions averaging. With regards to the impacts on consumer households at or near the Federal Poverty Level, Section VII. of the preamble, Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement, discusses the EPA's consideration of environmental justice concerns. The EPA initiated a study called NO_X Emission Control Technology Installation Timing for Non-EGU Sources to assess the timing needs for installation of controls on non-EGU sources. Section 4.3 of this study also discusses the EPA's consideration of system reliability for the pipeline transportation of natural gas due to control installation timing.

As explained in the proposal, the EPA found that most RACT rules and other standards reviewed by the EPA established applicability for engines based on design capacity rather than PTE.

To be consistent with established requirements for engines, the EPA selected a design capacity of 1,000 braking horsepower (bhp) for engines to capture the same size units identified in Step 3 of our analysis. Based on the Non-EGU Screening Assessment memorandum, engines with a PTE of 100 tpy or greater had the most significant potential for NO_X emissions reductions. The

EPA recognizes that the 1,000 hp design capacity as part of the applicability criteria captured more units than the EPA intended, particularly some low-use units and some units with emissions of less than 100 tpy being covered by the FIP's requirements. Although the individual contribution from any one engine to downwind nonattainment or maintenance receptors may be insignificant, collectively engines rated at this size threshold or higher in the states and industries covered by this final rule have substantial NO_X emissions which do cause or contribute to downwind air quality problems.

Therefore, pursuant to concerns raised by commenters on the proposed rule, the EPA has finalized an emergency engines exemption to ensure than this final rule focuses on larger, more impactful units and has instituted in the final rule an emissions limit compliance alternative using facility-wide emissions averaging, which will allow for facilities to prioritize emissions reductions from larger, higher-emitting units.

5.3.1.1 Applicability Threshold

Definitions and Affected Facilities Clarification

Comments:

Commenters (0275, 0330, 0334, 0403) request clarification on the definition of "Pipeline Transportation of Natural Gas" sources. The commenters define the pipeline transportation of natural gas to mean the movement of natural gas through an interconnected network of compressors and pipeline components, from field gathering networks near wellheads to:

> (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 local distribution company custody transfer stations.

Commenter (0275) states that their interpretation of the definition of "pipeline transportation of natural gas" as to not include the operations of distribution organizations is consistent with the NSPS and NESHAP that cover the natural gas transportation and storage sectors. The commenter adds the proposed definition of "pipeline transportation of natural gas" in the proposed rule is not as clear as the provisions of the NSPS and NESHAPs, and the definition of "operator" contained in proposed § 52.42(a) adds to this confusion. The commenter notes that in this proposed definition, an operator is "any person who operates, controls, or supervises a natural gas-fired engine subject to this regulation and shall include, but not be limited to, any holding company, utility system, or plant manager of such natural gas-fired engine," but the commenter states that the operator of a utility system is most likely involved in the distribution of natural gas to end-users and is not part of the pipeline transportation of natural gas sector.

Commenter (0334) states that the EPA only considered a small subset of the engines that would be covered by the rule. According to the commenter, the EPA stated in the RIA that the rule would cover pipeline engines in NAICS code 4862, and its analysis thus indicated that only a few hundred engines would be impacted by the proposal. However, the commenter states that the applicability language in the proposed rule is far broader and covers all large engines from wellhead to end user and would cover many thousands of engines. According to the commenters (0275, 0334), three companies alone report that they own over 2,500 engines that would be covered by the rule proposal. Commenter (0334) concludes that the EPA failed to sufficiently analyze the universe of engines that will be subject to the rule, as it evaluated engines with emissions of over 100 tpy but then wrote proposed a rule that did not limit applicability based on emissions. According to the commenter, the applicability rule language inappropriately includes far more engines than those analyzed by the Agency in developing the rule.

Commenter (0275) notes that the proposed use of the NAICS code for the pipeline transportation of natural gas industry sector as a guide to potential regulatory applicability does not accurately reflect the engines that the EPA intends to regulate under the proposed rule. According to the commenter, the pipeline transportation of natural gas industry sector is covered by NAICS 4862, and while the entities subject to regulation under the proposed rule are likely included in this NAICS code, certain local distribution companies have historically classified some storage and pipeline assets as being covered by NAICS 486210 rather than NAICS Code 221210, which more appropriately applies to the local distribution company's business of natural gas distribution. The commenter believes the use of NAICS Code 4862 as a guide for applicability is over-inclusive.

Commenter (0330) requests that the EPA clarify the applicability of the proposed FIP to RICE that are located downstream of the LDC's custody-transfer stations. Specifically, the commenter states that in the proposed definition for Pipeline Transportation of Natural Gas, the phrase "to end-users, including..." blurs the meaning within subparagraph (ii), which states "to large natural gas end-users, and to distribution organizations." The commenter proposes that this phrase "to end-users, including..." be removed from the definition, thus focusing on RICE that are integral to the upstream segments in the natural gas industry. The commenter adds that common vernacular and the use of terms like transport, transmission and storage of natural gas leads to a great deal of confusion when assessing regulatory applicability.

Commenter (0429) states that there is confusion about the definition of Pipeline Transportation of Natural Gas, and the reason for the confusion is that under the pipeline safety regulations of the Pipeline and Hazardous Materials Safety Administration, the term "pipelines" includes all pipes and appurtenances used to transport gas, including both those pipes operated at "transmission" pressure and those operated at lower pressures as "distribution." According to the commenter, some intrastate gas lines operated by local gas utilities can be categorized as operating at "transmission" pipeline pressures under the Pipeline and Hazardous Materials Safety Administration's regulations, even though they are part of the intrastate gas utility's local distribution system regulated by the state's utility commission. The commenter states that some smaller compressor stations would have a negligible effect on downwind state air quality, and it is not clear whether the EPA evaluated emissions from intrastate compressors operated by gas utilities. The commenter asserts that this would be necessary to provide a rational basis for imposing additional NO_X standards on the relatively small number of compressor engines deployed in local gas utility systems.

Commenter (0501) 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.” The commenter (0501) notes that 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.

Response:

Regarding the definition of “pipeline transportation of natural gas,” the EPA agrees that clarification and alignment with the definitions in other Federal rules that apply to this sector is appropriate. The final rule defines “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),” which is consistent with the EPA’s definition of “natural gas transmission and storage segment” in 40 CFR part 60, 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 has further clarified the definition to exclude natural gas production facilities and natural gas processing plants.

To further clarify the terms used within this definition, 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. While the EPA does estimate more engines will be subject to the rule than estimated at proposal, the revision of this definition will help clarify that operators of utility systems that distribute natural gas to the end-user are excluded from the rule, which is the EPA’s intent. This revision will exclude LDCs, operators downstream of LDCs, and intrastate gas lines operated by local gas utilities.

Regarding the NAICS code used as a guide to potential regulatory applicability, the EPA has included the NAICS code of 4862 in both the proposal preamble and the final rule preamble. This NAICS code captures businesses that may become subject to the rule. While it may include other businesses as well, the EPA would prefer to be overly broad to ensure that potentially regulated businesses are aware of the rule, its provisions, and the potential applicability of the rule to them. With the revision of the definition of “pipeline transportation of natural gas,” LDCs and operators downstream of them will largely be excluded, and the inclusion of additional NAICS for those operators, such as 221210, is not necessary.

Regulated States

Comments:

Commenter (0314) states that the EPA admits that Wyoming's pipeline and refinery industries do not need to be included in this regulation but are remaining in, nonetheless. According to the commenter, an area in Colorado is in nonattainment, and the EPA has required Colorado to take certain actions to reduce emissions and bring this area into compliance. The commenter continues, saying that as a result of those approved actions, the EPA states in the proposal that it is unnecessary for pipelines and refineries in Wyoming to install emissions controls, yet the EPA is still proposing that Wyoming industries install emissions controls in the event that the Colorado-centric actions do not come to fruition or do not achieve the expected emissions reductions. The commenter states that this goes against prior U.S. Supreme Court precedence barring the EPA from overcontrolling emissions reductions.

Commenter (0554) notes that for Wyoming, the last affected downwind receptor in Colorado is estimated to achieve attainment and maintenance of the ozone standard after full application of emissions reductions from the EGU sector, meaning that no emissions reductions from the non-EGU sector would be necessary. If emissions reductions from the non-EGU sector are underestimated, as the commenter believes, this would tip the over-control analysis for Wyoming, which is already borderline for inclusion of non-EGUs based on the EPA's own analysis. According to the commenter, nothing in the recent Maryland v. EPA decision that the EPA cites for its decision to include Wyoming non-EGUs in the proposal precludes the EPA from assuming that Colorado will be taking its own steps to address ozone nonattainment near Denver. The commenter states that based on its underestimate of emissions reductions from pipeline RICE in Wyoming and its failure to account for downwind emissions reductions in its over-control analysis, the EPA should conclude that regulating non-EGUs in Wyoming will result in over-control and remove this State from the non-EGU requirements of its proposal.

Commenter (0359) notes that the EPA's analysis reflects reductions from the Cement and Concrete Product Manufacturing and Pipeline Transportation of Natural Gas industries from 22 facilities located in West Virginia; however, the number of emissions units anticipated to be subject is more than double this number. The commenter has identified at least 52 potential non-EGU facilities that would be subject. The commenter claims that this under-counting of sources grossly misrepresents the cost of the proposal and overcontrols upwind states. The commenter states that any future modeling analysis should include emissions estimates from these units as well as an assessment as to whether West Virginia's contributions to downwind monitors may be over-controlled if all applicable units were to be included.

Response:

The EPA is deferring final action on the proposed FIP for Wyoming until further review of the updated air quality and contribution modeling and analysis developed for this final action can be completed.

The EPA acknowledges that more stationary engines will be subject to the rule than estimated at proposal. However, not all of these engines will be required to be controlled, as some already meet the emissions limits and some will be included in the emissions averaging approach, which will allow industry to control emissions from fewer engines at a site as long as the overall site-wide emissions are equal to or lower than what would be achieved if every individual engine met the applicable emissions limit in § 52.41(c). The EPA has re-run its Step 3 analysis using the updated estimate of engines that will be subject to the rule and has concluded that that the proposed emissions limits for pipeline transportation of natural gas are appropriate and necessary to reduce NO_X emissions in areas downwind of West Virginia facilities to reach and sustain attainment levels. As explained further in the section of the preamble to the final rule on Assessing Cost, EGU and Industrial Source NO_X Reductions, and Air Quality, the EPA also determined in its overcontrol analysis that the application of these emissions limits will not result in overcontrol. Further, the estimated costs have been updated to reflect these and other components of the EPA's revised analyses. More information on costs can be found in the document, "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," in the docket for this action.

Applicability Threshold

Comments:

Commenter (0353) claims that the proposed rule's estimate of emissions reductions from stationary engines is based on incorrect assumptions. The commenter states that the proposed rule incorrectly assumes that stationary engines rated at 1,000 horsepower or more will emit 100 tpy or more of NO_X. The commenter contends that many of its members use hundreds of stationary engines with a capacity of 1,000 horsepower or more, but very few of those have NO_X emissions of 100 tpy or more due to the NSPS for stationary engines that establishes a lower emissions limit for engine manufacturers. The commenter states that the EPA should explain the basis for its review and identify the materials used in its support. The commenter also notes that the proposed rule never clearly states the number of stationary engines the EPA finds would be subject to the proposed NO_X emissions limit. The commenter asserts by making the horsepower rating the threshold for regulation, the EPA will be regulating sources emitting less than 100 tpy and dramatically underestimates the number of stationary engines that would be subject to the rule. Based on information in the docket, the commenter believes the EPA identifies 218 sources, but the commenter believes more than 10,000 stationary engines will be subject to the proposed rule. The commenter states that his means the proposed rule likely underestimates the total NO_X emissions that could be achieved and certainly underestimates the midstream sector's compliance costs. The commenter says the EPA should reconsider the proposed NO_X emissions limits, as with more stationary engines subject to the final rule than anticipated, the EPA can reduce the emissions limits to some degree while still obtaining an equivalent cumulative emissions reduction.

Commenter (0501) claims that the EPA has vastly underestimated the number of engines that would be subject to its proposed rule because its applicability threshold does not take utilization into account. According to the commenter, the EPA explains that a NO_X emissions rate of 100 TPY is the screening basis for identifying affected units, which for pipeline transportation RICE, the EPA equates to a 1,000 hp applicability threshold. The commenter states that this assumption is incorrect because an uncontrolled unit would need to operate a significant portion of the year, which is not consistent with interstate natural gas transmission operations. The commenter provides an example in which, depending on the uncontrolled NO_X emissions factor used (*e.g.*, EPA AP-42 factor versus EPA factor from NO_X SIP Call Phase 2 rule), a 1,000 hp two-stroke lean burn engine would need to operate 62 percent to 86 percent of the year to emit 100 TPY. According to the commenter, transmission compressor stations are designed to meet peak demand days and typically include significant over-capacity, which results in average annual utilization on the order of 40–45 percent for most natural gas transmission pipelines, with some units operating only when needed during peak demand during cold winter weather events. The commenter adds that a white paper from the Pipeline Research Council International ("PRCI") compiled subpart W utilization data for hundreds of affected facilities over six years, which shows 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, and for RICE at storage facilities, over 80 percent of the units operate less than 50 percent of the time. According to the commenter, 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, the commenter says, 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. The commenter also states that for natural gas transmission compressor stations, smaller affected units (*e.g.*, those between 1,000 hp and 2,000 hp) are also more likely to operate less frequently and have lower annual and ozone season emissions. The commenter notes when demand is low, many or all units at a RICE compressor station will be idle, and typically the RICE with lowest the utilization are the smaller affected RICE at the facility. The commenter asserts that if an hp threshold is used as a proxy to identify affected units, utilization should be factored into that threshold. The commenter concludes that more than five times as many RICE units are affected than the EPA estimated because utilization was not properly considered in defining the 1,000 hp threshold. According to the commenter, the EPA must reevaluate the threshold and develop a proposal that better reflects the realities of the industry.

Commenters (0275, 0334, 0359, 0365, 0501, 0554) state that the horsepower rating of an engine does not necessarily correspond to its annual emissions, and 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.

Commenter (0554) states that the EPA did not explain how it decided that pipeline RICE greater than 1,000 hp would be likely to emit more than 100 tpy of NO_X. According to the commenter, the EPA assumed that pipeline RICE emit at an uncontrolled emissions rate of 16.8 grams per horsepower hour (g/hp-hr) and that such engines typically operate for 7,000 hours per year. The commenter states that with those assumptions, the EPA determined that an 800 hp engine would hit 100 tpy, and the EPA apparently rounded up to 1,000 hp. The commenter notes that the EPA also compared this result to the NEI and identified 200 engines above 1,000 hp that had emissions above 100 tpy, while only two engines smaller than 1,000 hp reported emissions above 100 tpy. The commenter states that the NEI is prone to overestimation, and the EPA does not explain whether the relatively small subset of 200 engines represents the bulk of the industry. The commenter also disagrees with the EPA's assumptions regarding emissions and operating hours for typical pipeline RICE. While the EPA assumes an uncontrolled emissions rate of 16.8 g/hp-hr, the commenter states that the vast majority of pipeline RICE today already have some built-in control measures, since the EPA standards have required manufacturers to include those measures since the early 2000s. The commenter estimates that 90 percent of its fleet of engines operate well below the EPA's assumed emissions rate and notes that most of those units are limited by their air permits to 3.0 g/hp-hr or less. The commenter further points out that the EPA's AP-42 emissions factors for pipeline RICE also indicate emissions are well below 16.8 g/hp-hr, noting that the highest emissions factor any type of RICE is 4.08 lb/mmBtu (4.748 g/hp-hr) for four-stroke lean burn (4SLB) engines.

Commenter (0554) believes the EPA's assumption regarding typical operating hours for a pipeline RICE of 7,000 hours per year is off-base, noting that its GT&S engines greater than 1,000 hp operate, on average, around 2,200 hours per year. The commenter notes that the EPA's TSD cites two different sources of information on RICE units, indicating that average operating hours are 2,000 and 3,000 hours a year, respectively, but the EPA instead relies on a third source that assumes 7,000 operating hours a year, without explaining its decision to do so. According to the commenter, by overestimating emissions rates and operating hours, the EPA has underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy NO_X annually, (*i.e.*, only engines much larger than 1,000 hp are likely to emit at the level the EPA deemed appropriate for regulation).

Commenter (0554) argues that the EPA should raise the hp threshold from 1,000 hp to at least 2,000 hp and recommends the EPA use a screening threshold for non-EGUs of 150 tpy to be more consistent with the approach taken in previous CSAPR rules and to ensure parity between EGUs and non- EGUs. The commenter believes the EPA's emissions rate and operating hour assumptions are both at least double what they should be, and that if the EPA corrects even one of these unrepresentative assumptions, the hp applicability threshold would, at a minimum, double as well. The commenter opines that even at a higher hp applicability threshold, the proposed rule would likely apply to more engines than the EPA currently expects because the population of pipeline RICE is much larger than the EPA has indicated. The commenter concludes that as a result, the emissions reductions required by the proposed rule would likely be greater than what the EPA has assumed, but the proposal would affect a smaller population of engines.

Commenter (0359) also notes that many West Virginia facilities that have natural gas fired spark ignition 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.

Commenter (0350) notes that the EPA has undercounted Engines that would be affected by the proposed rule and that therefore the EPA did not fully account for NO_X emissions reductions resulting from emissions controls on Engines. More broadly, the Texas Transport Working Group identified multiple flaws in the EPA's photochemical modeling, which call into question the basis for the proposed rule. The commenter believes to remedy these foundational issues, the 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 define the sector subject clearly 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. Commenter (0350) is willing to work with the EPA to achieve these initial objectives.

Commenter (0554) states the EPA failed to identify numerous engines operated by the BHE Pipeline Group that would nonetheless be covered by the proposal if the EPA retains its current 1,000 hp applicability threshold. Commenter (0554) requests for the EPA to ensure that its analyses regarding the number of engines impacted by the rule are adjusted to accurately reflect the individual units that would be covered, regardless of the applicability threshold that the EPA ultimately selects.

Commenter (0505) states the EPA's analysis on Natural Gas Pipeline Transmission sources does not correspond with the proposed FIP's requirements. The EPA's proposed FIP would control emissions from engines rated 1,000 horsepower or greater. However, the EPA's technical analysis calculates NO_X emissions reductions from only 20 compressor engines in Texas in the natural gas pipeline transmission sector using reported NO_X emissions over 100 tpy as a surrogate. The EPA's use of this surrogate data underestimates the impact of the proposed FIP, since reported emissions inventory data indicates 600 percent more engines (at least 120 engines) in Texas would be impacted. Additionally, the commenter's rules already require at least 10 percent of potentially impacted engines to be controlled to or below the EPA's proposed emissions limits, so no further emissions reductions will be achieved from these engines.

Response:

Under the CAA, a Moderate nonattainment classification has a major source permitting threshold of 100 tpy for NO_X and VOC. Considering this major source threshold, the EPA has chosen this as a basis for regulation in this rule and in previous interstate emissions transport rulemakings. Based on the EPA's analysis conducted for the proposed rule, 1,000 hp engines were estimated to emit NO_X at or above 100 tpy. Using 1,000 hp as the applicability threshold for engines and based on a review and analysis of the EPA's 2019 NEI emissions inventory data, the EPA estimates that 3,005 stationary engines will be subject to the final rule; however, we recognize that many low-use engines are captured by the 1,000 hp design capacity applicability threshold. To focus emissions reduction efforts on the highest emitting units, the EPA is establishing exemptions for emergency engines, as well as including new emissions averaging provisions for engines. In addition, the EPA is also clarifying that the rule does not apply to engines that are part of the local distribution network. These provisions of the final rule are intended to increase the likelihood that low-use or low-emitting engines will not be required to install emissions controls.

Compliance Alternatives

Comment:

Commenter (0275) notes that its subsidiary, Bluewater, would fall into the pipeline transportation of natural gas industry sector, as defined by the proposed rule. The commenter notes that Bluewater operates 6 engines at its compressor and booster stations with a maximum rated capacity of more than 1,000 hp and annual 2021 NO_X emissions for these engines range from 0.7 tons to 6.2 tpy. The commenter remarks that retrofitting these engines with NO_X emissions controls is likely not cost effective. Accordingly, the commenter requests that the EPA revise the proposed rule to provide that otherwise-covered engines could comply through acceptance of an enforceable mass-based emissions limitation of less than 100 tpy of NO_X in lieu of meeting the emissions rates in the regulation.

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 and to capture the sizes of units identified in Step 3 of the analysis, the EPA proposed an engine design capacity of 1,000 as the threshold for applicability. Based on a review of public comments, the EPA recognizes that this threshold, as proposed, make more units than intended subject to the rule, particularly some low-use units. Therefore, in the final rule, the EPA is establishing exemptions for emergency engines, as well as including new emissions averaging provisions for engines, to ensure that the final rule focuses on larger, more impactful units. In addition, the EPA is also clarifying that the rule does not apply to engines that are part of the local distribution network. These provisions of the final rule are intended to increase the likelihood that engines like those described by the commenter here will not be required to install emissions controls.

Cost Analysis

Comments:

Commenters (0365, 0334) state that the EPA did not consider engines larger than 1000 hp that emit below 100 tpy in the calculations for cost or potential emissions reductions. The commenters note that despite identifying engines that meet the 1000 hp threshold with emissions below 100 tpy, the EPA did not include those engines in the cost calculations and estimated emissions reductions in the Screening Assessment. The commenters also state that the EPA calculated the emissions reduction impact based on only 23 facilities with 47 engines, however the LDEQ permitting database indicates there are currently 103 facilities with 477 permitted engines that would be impacted by the proposed rule.

Response:

The EPA has updated its analyses of impacted facilities and units, emissions reductions, and cost impacts for the final rule. The results of these analyses can be found in the document, *"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,"* in the docket for this action. The EPA estimates that 3,005 engines will be subject to the final rule, with NO_X emissions reductions of 32,247 tpy at annual cost of $385 million. In these revised analyses, the EPA included all engines rated at 1,000 hp or larger in the calculations of estimated costs and emissions reductions, regardless of whether their emissions are above or below 100 tpy.

Affected RICE Estimates

Comments:

Commenters (0501, 0554) state that the number of RICE units in the pipeline transportation of natural gas industry that would be covered by the proposed rule is out of line with the number of units that meet the 1,000 hp threshold industry wide. According to the commenters, while the EPA's estimates show that 307 engines would be covered, there are actually more than 1,000 units that would become subject to the proposed rule at a threshold of 1,000 hp. Commenter's (0554) individual pipeline companies have noted similar disparities in the number of engines the EPA claims would be covered versus the number that actually meet the 1,000 hp threshold. The commenter notes that Northern Natural Gas, for example, has 33 engines greater than 1,000 hp, but the EPA only identifies 16 as being covered by the proposal. The commenters state that because the EPA has underestimated the population of engines to which its proposal would apply, it has also underestimated the emissions reductions its proposal will require. Accordingly, the EPA's over-control analysis is based on underestimated emissions, which suggests that over- control is more likely to occur than the EPA's analysis would indicate.

Commenter (0501) adds that based on information currently available to INGAA members, an estimate of unit counts and resulting emissions reductions was prepared:

- 1,199 engines would require control, which is four times the EPA estimate.
- Approximately 181 additional engines owned or operated by INGAA members currently include emissions controls but cannot meet the proposed NO_X limits, thus requiring incremental control.
- Another 678 units owned or operated by INGAA members that meet the emissions 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.
- The EPA projects NO_X reductions of 55,546 tpy for all covered states combined, but INGAA's estimate indicates additional reductions in most states and total reductions of over 57,000 tpy more than the EPA's estimate, which is 203.4 percent of the reductions the EPA estimates. These estimates do not include pipeline companies that are not INGAA members, and INGAA data estimates do not include RICE in the gathering and boosting segment located between the gas production and gas processing segments, which would also be affected units based on the proposed definition of "pipeline transportation of natural gas" and may make the total count of affected units be more than double the values presented above for transmission and storage facilities operated by INGAA members.

Commenter (0501) compiled a state-by-state assessment of affected pipeline transportation RICE units for comparison to the EPA estimates. According to the commenter, these data demonstrate show serious flaws in the current basis of support for the proposed rule. According to the commenter, this underscores the need for the EPA to substantially revise, if not re-propose, the proposed rule.

Commenter (0380) states the EPA significantly under-estimates 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 emissions reductions. This underestimation of unit counts is primarily due to the EPA's failure to account for typical operational use (*i.e.*, "utilization") in T&S as compared to other sectors. On average, system utilization in the United States is on the order of 40 percent for compressor stations and lower for underground storage facilities. For the proposed rule, the EPA analysis identified non-EGU units with actual emissions above 100 tpy (tpy), which the 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, due to a lower utilization rate than assumed by the EPA. This undercounting also causes underestimation of control costs.

Commenter (0353) states that it appears the EPA dramatically underestimated the number of Stationary Engines that would be subject to the proposed rule, and the EPA's Step 3 air quality modeling, emissions assumptions, and NO_X emissions reduction strategies require re-evaluation using an accurate number of engines. According to the commenter, underestimating the number of Stationary Engines subject to the proposed NO_X emissions limitation would mean that the EPA underestimated emissions reductions from Stationary Engines, upwind state emissions as a whole, and total compliance costs, which would not only result in an unnecessary over-control of emissions, but would impose new and excessive compliance costs on the midstream industry without any justification under the CAA. The commenter notes that with more Stationary Engines than what the EPA assumed, a more modest emissions limit from these sources could still achieve significant downwind emissions reductions. The commenter suggests that as an alternative, the EPA could explore exempting Stationary Engines already subject to NSPS, which would regulate older, higher-polluting Stationary Engines that are already approaching the end of their service lives.

Response:

At proposal, the EPA estimated that 307 stationary engines would be subject to the rule. After further review of the 2019 NEI and considering changes to the proposed applicability requirements made in this final rule, the EPA estimates that 3,005 stationary engines will be subject to the rule. However, not all of those engines will be required to be controlled, as some already meet the emissions limits and some will be included in the emissions averaging approach, which will allow industry to control emissions from fewer engines at a site as long as the overall site-wide emissions are equal to or lower than what would be achieved if every individual engine was controlled. In addition, the EPA is excluding emergency engines and those that are part of the local distribution network. The EPA has re-run its Step 3 analysis using this information and has concluded that the proposed emissions limits are appropriate and necessary to reduce NO_X emissions in downwind areas to attainment levels. The EPA also determined in its overcontrol analysis that the application of these emissions limits will not result in overcontrol. The EPA's revised estimate of NO_X emissions reductions from engines in Pipeline Transportation of Natural gas during the ozone season is 32,247 tpy. With the addition of the option to employ a facility-wide emissions averaging approach, owner/operators with multiple engines will have the ability to prioritize control of older, higher-polluting engines, as one commenter suggests.

5.3.1.2 Emissions Limits

Comments:

Commenter (0353) believes the proposed rule should clearly state that Stationary Engines already regulated under the applicable NSPS are exempt from the FIP. The commenter states that the NSPS already limits Stationary Engines manufactured after July 2010 to emissions of 1.0 gram of NO_X/hp-hr, which is lower than the proposed NO_X emissions limits at Table 1.B-2 of the proposed rule. According to the commenter, the proposed rule states that NSPS regulations for Stationary Engines "are reflected for select source categories," however, the EPA does not explain what that means. The commenter notes that for other non-EGU emissions sources, including municipal waste combustors and Portland cement plants, the proposed rule explicitly considers the existing NSPS emissions limits and proposes to impose more stringent limits. The commenter adds that the proposed rule does not discuss the NSPS emissions limits for Stationary Engines or otherwise describe how they were considered. According to the commenter, if the EPA declines to exempt Stationary Engines that are already regulated under subpart JJJJ, it should then explain how it considered the existing emissions limits.

Commenter (0501) requests that the provisions specified in proposed section 52.41(c)(1)-(3), specifying emissions limits, be revised as follows:

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 then you must meet a nitrogen oxides (NO_X) emissions limit of 1.0 grams per hp-hr (g/hp-hr).

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 then you must meet a NO_X emissions limit of 1.5 g/hp-hr.

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 then you must meet a NO_X emissions limit of 3.0 g/hp-hr.

Response:

The EPA acknowledges the commenter's concern and agrees that stationary spark ignition engines that are already regulated under 40 CFR part 60, subpart JJJJ should be exempt from the FIP. The EPA has clarified in the final regulatory text at § 52.41(b) that owners and operators of natural gas fired two stroke lean burn manufactured after July 1, 2007, and natural gas fired four stroke lean burn engines manufactured after July 1, 2010, that are meeting the emissions limits in Table 1 of 40 CFR part 60, subpart JJJJ do not have the comply with the requirements of § 52.41 of the final rule.

The EPA agrees with the typographical revisions offered by commenter 0501 and has updated the regulatory text of subsection 52.41 to reflect this change.

<u>Covered Components</u>

Comments:

Commenter (0558) agrees with the EPA's proposal that natural gas pipeline fossil fuel fired prime movers should be included in the final rule. Natural gas pipeline fossil fuel fired prime movers operate to pressurize pipelines and facilitate the transportation of natural gas through a network of pipeline spread across the entire country. They are even more concentrated in regions that are sources of large conventional and shale gas reserves, such as the Marcellus and Utica shale formations, as they supply a large part of the country with natural gas fuel. In this fleet of fossil fuel fired natural gas pipeline compressor prime movers there remains a large number of legacy fossil fuel fired pipeline compressors that have relatively uncontrolled NO_X emissions. Fossil fuel fired pipeline compressor prime movers contribute to peak ozone season NO_X emissions as they respond to the high natural gas fuel demand to support larger and larger shares of natural gas fueled electric generation during the hot weather often associated with high ozone events.

While commenter (0558) supports the inclusion of fossil fuel fired internal combustion engine prime movers in the EPA's proposal, commenter (0558) recommends that fossil fuel fired combustion turbine pipeline compressor prime movers should also be included in the EPA's proposal. There are many hundreds of combustion turbine powered pipeline compressor prime movers installed to support natural gas pipeline operations. Many of these combustion turbines are legacy units in excess of 50 years old, have output ratings in excess of 30,000 hp, and have permit NO_X rate limits reflective of little to no NO_X control.

Commenter (0758) states the EPA proposes to set standards only for RICE used at natural gas pipeline transmission facilities. RICE are used throughout the oil-and-gas industry, including in the production, gas-processing, and transmission and storage sectors. The same make and model of engine are often used in more than one segment of the industry. In some cases, an individual engine may be relocated from one segment to another. For example, a particular engine could be moved from a transmission compressor station to a gas processing facility. Because the emissions reduction potential is comparable across segments, regulators typically set emissions limits that apply based on engine type, regardless of where in the industry the engine is used.

Commenter (0758) notes the EPA's decision to focus on the pipeline segment is a function of its screening assessment. As the first step of this assessment, the EPA seeks to identify industry segments where the greatest emissions reductions could be obtained. At the second step, the EPA attempts to identify cost-effective emissions control strategies within the industry segments selected. Finally, the EPA evaluates the emissions reduction potential and estimated air quality impacts of the selected control strategies. See 87 Fed. Reg. at 20082.241. While this is generally a reasonable way to identify emissions reduction opportunities, where the EPA determines that it is possible to reduce emissions in a cost-effective way from a piece of equipment that is used in multiple industry segments, the EPA should consider adopting uniform standards for that piece equipment, regardless of the industry segment in which it is used. Adopting uniform standards makes sense here, because it will lead to greater emissions reductions and ensure that polluting engines are not simply shifted from one industry segment to another. Moreover, the cost-effectiveness of reducing emissions from these units is likely to be identical regardless of where in the supply chain they are deployed.

Commenter (0758) argues pipelines are responsible for about 34 percent of the generation from gas-powered RICE in the oil-and-gas industry. A logical way to strengthen the proposed rule would be to apply the proposed RICE emissions standards to all the engines in the oil-and-gas industry. Extending the rule to the gas processing sector makes particular sense, since the RICE fleet used in this segment is similar to the fleet used at pipeline facilities, and the vast majority of the of the nation's gas processing capacity is located in states subject to non-EGU limits under the proposed rule, including California, Illinois, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming.

Commenter (0758) adds, applying the proposed RICE emissions limits upstream of the pipeline segment may provide significant co-benefits. Because upstream engines do not burn pipeline quality gas, they may emit more unburned hydrocarbons (including VOCs and hazardous air pollutants) during combustion. Thus, implementing control techniques that increase combustion efficiency—such as NSCR catalytic reduction—may provide greater co-pollutant reductions at upstream facilities than at pipeline facilities.

Commenter (0758) believes the EPA should consider requiring electrification of smaller engines to provide for greater emissions reductions and reduce the risk of under-control. While these engines emit less pollution per unit than larger engines, their emissions are cumulatively significant. Ensuring that emissions limits for these engines are tightened in lockstep with the standards for larger engines is important to avoid creating a perverse incentive that would encourage regulated parties to use multiple smaller engines instead of one larger engine (which would likely mean more pollution per horsepower hour).

Commenter (0758) argues electrification of compressor stations has long been recognized as an available and cost- effective NO_X control option for RICE. CARB has determined that "the majority of beam-balanced and crank-balanced oil pumps in California are driven by electric motors," and this was already true more than 20 years ago. CARB concluded that electrification must be a cost-effective option if operators were already deploying electric engines for these sources. CARB's analysis found that replacing a 500-to-1000 hp RICE with an electric motor would cost $1,100 per ton of NO_X eliminated (1999 dollars). For engines in the 150 to 500 hp range, the cost was even lower, at $900/ton in 1999 dollars. The EPA also evaluated the emissions reduction benefits of engine electrification as part of the Natural Gas STAR Program. In PRO Fact Sheet No. 103, the EPA reported that a partner replaced two 2,650 hp reciprocating compressors, two 4,684 reciprocating compressors, and one 893 hp reciprocating compressor with four 1,750 hp electric compressors. The total cost of this replacement, the cost of electricity, and the fuel gas savings associated with this retrofit are reported in the Fact Sheet. Although the Fact Sheet did not specifically report the amount of NO_X reduction achieved, one analysis found that the project would have reduced NO_X at a cost of $2,766 per ton or lower (depending on how many hours a year the engine operated), assuming that the RICE emitted at an uncontrolled rate of 16.8g/hp-hr.

Commenter (0758) also mention Electrifying RICE would eliminate onsite methane, HAP, and VOC emissions from the engine entirely. The EPA must give appropriate weight to the substantial co-benefits that could be achieved by expanding and strengthening the proposed RICE emissions standards. When RICE operates, hydrocarbons present in the fuel pass through the engine and are emitted in the exhaust. This may result in emissions of methane, VOCs, and hazardous air pollutants. The rate at which an engine emits unburned hydrocarbons depends on the engine type. “Lean-burn” engines have an average methane slip of 3 percent of methane feed gas, while rich burn engines average 0.4 percent methane slip. RICE used at upstream facilities are more likely to emit VOCs and hazardous air pollutants, because they are burning unprocessed gas. As the EPA has explained, “[i]t appears that after-exhaust controls, such as selective noncatalytic reduction (SNCR),” reduce methane slip. Electrification will have significant co-benefits, in terms of greenhouse gas, HAP, and VOC reductions.

Response:

The EPA disagrees with the recommendation that fossil fuel fired combustion turbine pipeline compressor prime movers be included in the final rule. As discussed in the Final Non-EGU Sectors TSD, an analysis of the NEI indicated that reciprocating engines are the largest collective sources of NO_X emissions from the Natural Gas Transportation Industry in the states affected by the FIP. The Non-EGU Screening Assessment memorandum[79] additionally described that the largest potential NO_X emissions reductions are from natural gas-fired spark ignition engines. Consistent with the proposed rulemaking, and lacking compelling additional information from commenters, the EPA concludes that based on the NEI data evaluated, there is no potential for significant emissions reductions from turbines in the states covered by the proposed FIP.

Although it is true the same and similar type engines as those to be regulated under this FIP are also used in various other oil and gas segments and other sectors all together, the EPA focused on the pipeline segment based on the results of the screening assessment. As discussed in the preamble to the proposed rule, the EPA’s approach to identifying control stringency levels for non-EGU sources was determined based on identifying where the potential NO_X reduction was the highest and having the greatest impact on downwind air quality. The Pipeline Transportation of Natural Gas segment of the industry was identified as one of the top industries or “Tier 1,” where the largest emissions reductions could be obtained.[80] Secondly, the EPA also determined that reducing NO_X emissions from pipeline engines is cost-effective. This conclusion has not changed and the final rule contains emissions limits for natural gas fired spark ignition engines only from the pipeline transportation sector.

In response to comments regarding the electrification of stationary engines, if an owner or operator replaces a stationary natural gas fired engine with an electric motor, the new electric motor unit would not be an affected unit under §52.41(b) of the rule and would therefore not be subject to the FIP. Such a unit cannot be included in the facility-wide averaging plan either, as only affected units may be used for facility-wide emissions averaging purposes under the final

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[79] See *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (“Non-EGU Screening Assessment memorandum”), which is available in the docket for this rulemaking.

[80] 87 FR 20083.

rule.

Control Options

Comments:

Commenters (0235, 0295, 0350, 0353) have serious concerns with the 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 existing engines to achieve the one-size-fits-all emissions standards set forth in the Engine Proposal. While commenter (0350) does not oppose emissions 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.

Commenter (0353) states generally older four-stroke and two-stroke lean burn engines will not be able to achieve the proposed NO_X emissions limits. Conversion kits are available for several models that can reduce emissions; however, such kits are not made for all models, especially older Stationary Engines. 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 entirely – usually at a cost of $2 million to $4 million each. The EPA has not accounted for these replacement costs. Commenters (0235, 0350, 0353) provide background on the type of control options available for each Engine type (*i.e.*, 4-stroke rich burn (4SRB), 4SLB, and 2-strok lean burn (SLB).

Commenters' (0235, 0295) facilities are currently regulated by the MDAQMD to have, at the minimum, Reasonably Available Control Technology (RACT) and in many cases Best Available Control Technology (BACT) or BARCT. Historically, the commenters have found that additional controls/requirements added to facilities already equipped with RACT, BACT or BARCT does not gain the estimated amount of emissions reductions due to operational factors inherent in the preexisting and pre-controlled equipment. This is exacerbated by the fact that the specific methods to achieve RACT, BACT or BARCT control levels are highly variable depending upon the facility in question. Without a robust analysis of the situation unique to each potentially affected facility the commenters are concerned that the estimated emissions reductions as expressed in the proposed FIP would not be realized.

4SRB Engines

Commenter (0350) operates approximately 150 4SRB Engines that would be subject to the Engine Proposal. Regarding 4SRB Engines, the EPA states that its proposed limits are designed to be achievable for existing Engines by installing NSCR. Commenter (0350) 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. It is worth noting, 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.

Commenter (0350) continues, NSCR uses the residual hydrocarbons and 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 N2. 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.

Commenter (0350) continues, 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 commenter's (0350) 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.

Importantly, however, some of commenter's (0350) 4SRB Engines cannot achieve the 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 the 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 commenter's (0350) engines.

Based on preliminary assessments, commenter (0350) 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, Commenter (0350) would also have to add layered technologies such as AFRC to at least three of these 4SRB Engines 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, Commenter (0350) also operates an additional approximately

25 4SRB Engines that already have NSCR, but that would require commenter (0350) also add AFRC to meet the 1.0 g/hp- hr limit. Commenter (0350) also operates approximately 10 4SRB Engines that have all available controls on them. Commenter (0350) 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 the 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. Even where NSCR or layered combustion is feasible, it is cost-prohibitive in some cases.

Additionally, commenter (0554) opposes the EPA's alternative limit of 0.5 g/hp-hr because significant uncertainty remains as to whether the control technology the EPA chose for 4SRB engines—NSCR—can achieve 0.5 g/hp-hr across all units.

By contrast, commenter (0758) argues the proposed limit of 3.0 g-NO_X/hp-hr is less stringent than the applicable new source performance standard, which has required new engines of this type to meet a standard of 1.0 g-NO_X/hp-hr since July 2010. In addition, numerous states have adopted more stringent emissions standards for existing engines of this type, with "some states hav[ing] required limits equivalent to or even lower than 0.2g/hp-hr."

Commenter (0758) continues, Colorado's standard for 4SRB engines with horsepower of 1000 or greater is 0.8 g-NO_X/hp-hr. The Colorado Air Pollution Control Division found that 104 of the 207 engines meeting this description, approximately 50 percent, were already operating below this standard. The Division found that the remaining engines could achieve the standard by implementing either a high energy ignition system, which reduces NO_X emissions by about 10 percent, or a combination of NSCR with an air-to-fuel ratio (AFR) controller, which reduces NO_X by 90 percent or more. The Division found that it would cost $1,016,855 to implement NSCR with AFR at all of the covered engines in the State, resulting in annualized total costs of about $13,860 per engine. This would reduce NO_X emissions by 626 tpy, at a cost of $1,624 per ton.

4SLB Engines

Commenters (0235, 0295, 0353) believe achieving a 1.5 g/hp-hr NO_X emissions limit is possible by using SCR is not a practical option as most Stationary Engines used in the midstream sector are located at unmanned facilities. This raises two significant problems:

1. First, storing the ammonia needed for an SCR system at an unmanned facility raises significant safety concerns. The industry already struggles with trespassers and equipment theft. GPA Midstream believes it would be highly irresponsible to effectively require midstream companies to store a hazardous chemical at unmanned facilities in primarily rural areas.
2. Second, the reliable operation of an SCR system requires monitoring ammonia storage, control, metering, injection rates, and leak detection systems. Where issues arise, such as ammonia slip or nozzle clogs, these need to be detected and corrected immediately. This makes SCR operation impractical at an unmanned facility. The EPA should reconsider an alternate means of emissions reduction for four-stroke lean burn engines or calculate the significant additional cost of having to maintain a team of SCR system operators at each

> Stationary Engine site. When accounting for the cost of full-time staff to man each facility, combined with the SCR system's operation (which may require providing electricity to non-electrified sites – another cost that the EPA may not have accounted for), GPA Midstream is skeptical that SCR is cost-effective even at $7,500 per ton given that the proposed rule would only reduce emissions from 2.0 g/ hp-hr (the current NSPS emissions limit) to 1.5 g/hp-hr. The EPA should provide a more detailed analysis demonstrating that SCR is cost-effective for four-stroke lean burn engines.

Commenter (0350) operates approximately 310 4SLB Engines that would be subject to the Engine Proposal. The 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. 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.

Commenter (0350) states 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 commenter (0350) has never retrofitted units with SCR in its natural gas system—which is an important fact given that commenter (0350) is one of the largest natural gas infrastructure and transmission companies in the U.S. This is largely because SCR is an extremely expensive and complex control technology 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.

Commenter (0350) continues, 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. However, high pressure fuel injection and pre-chamber ignition are not techniques employed for 4SRB engines, so commenter (0350) 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.

Commenter (0350) continues, 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. 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, commenter (0350) 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. In these particular cases, application of SCR is economically infeasible on a cost-per-ton basis.

Commenter (0758) argues the proposed a limit of 1.5 g-NO_X/hp-hr is less stringent than the applicable new source performance standard, which has required new engines of this type to meet a standard of 1.0 g-NO_X/hp-hr since July 2010. In addition, numerous states have adopted more-stringent emissions standards for existing engines of this type, with "some states hav[ing] required limits equivalent to or even lower than 0.5g/hp-hr." Commenter (0758) believes the EPA should strengthen the standards for these engines. Colorado's standard for existing 4SLBs with horsepower of 1000 or greater is 1.2 g-NO_X/hp-hr. The Colorado Air Pollution Control Division ("Division") found that 378 of the 589 engines meeting this description, approximately 2/3, were already operating below this standard. The Division found that the remaining engines could achieve the standard by implementing control strategies such as high energy ignition systems, advanced air to fuel ratio controllers, electronic ignition systems, low emissions combustion technology, or SCR. In general, these technologies would lead to cost-effective reductions of NO_X.

2SLB Engines

Commenter (0350) operates nearly 500 2SLB Engines that would be subject to the Engine Proposal. Regarding 2SLB Engines, the EPA states its proposed limit of 3.0 g/hp-hr is achievable for existing Engines by retrofitting them with layered combustion. These layered combustion options are the same as those for 4SLB Engines, including turbocharging, high pressure fuel injection, and pre-chamber ignition. As with the discussion of these control technologies for 4SLB Engines offered, commenter (0350) emphasizes that such technologies are not universally feasible for all 2SLB Engines.

Commenter (0350) continues, 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, commenter (0350) 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 commenter (0350) 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, commenter (0350) would still be required to apply SCR to meet the proposed standards. These considerations do not account for costs-per-ton estimates. Even where SCR or layered control is feasible, it is cost-prohibitive in many cases.

Commenter (0350) continues, turning back to all engine types, for all three classes of Engines, the EPA notes that sources are free to install "another control technology" as long as the unit is still able to meet the emissions limit. However, there are no other control technologies. The EPA has identified them all: NSCR, SCR, and layered combustion. While commenter (0350) recognizes that technologies continue to advance, it is highly unlikely that technologies in this arena will advance faster than the 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.

Commenter (0350) states the 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 the 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. Commenter (0350) 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. The negative consequences of the EPA's over-reaching and one-size-fits-all proposal are significant and underscore the need for a revised and alternative approach.

Commenter (0501) adds the EPA determined that the majority of affected units were 2SLB engines, and an EPA report 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 referenced. The technology basis and emissions standard for 2SLB evaluated in the 2000 Pechan Report are consistent with the NO_X standard for 2SLB units in the proposed rule as well as the EPA's emissions standard for reconstructed or modified units (*i.e.*, units requiring retrofit) in subpart JJJJ.

Commenter (0501) continues, the docket document summarizing the EPA reduction estimates includes much higher control levels than those the EPA previously determined to be realistic. For 2SLB units with LEC, the EPA now typically applies 97 percent reduction. From the baseline in the previous EPA report, this equates to an emissions 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 emissions level achievable for existing units. Similarly, the EPA estimates over 95 percent reduction for NSCR on rich burn engines, which equates to an endpoint less than 0.5 g/bhp-hr. The EPA notes that it has reviewed results within this range for all engine types [99], but this assertion does not adequately justify the EPA's departure from the Agency's well-documented conclusions in the EPA NO_X SIP Call Phase 2 rule docket.

If provided sufficient time to install controls, commenter (0554) believes that the emissions limits in the rule are achievable with one exception: for 2SLB engines, the proposed 3.0 g/hp-hr limit may not be achievable by all of the RICE to which it would apply. BHE has evaluated its fleet of pipeline RICE and determined that most of those engines should be able to achieve the 3.0 g/hp-hr limit using layered combustion, which BHE understands to include turbocharging and high-pressure fuel injection.

Commenter (0554) continues, however, given the wide range in vintage, size, and model of engines across the fleet, some uncertainty remains as to whether layered combustion will be sufficient to achieve the proposed emissions limits at all BHE's engines because layered combustion is not a one-size-fits-all technology. Furthermore, the notion of layering multiple combustion controls is not proven across the wide variety of units within the BHE fleet. While the concept that additional controls will produce additional emissions reduction benefits sounds good in theory, combustion controls functionally change the combustion parameters of the units on which they are employed — essentially amounting to an engine redesign. Since commenter (0554) has not attempted to layer these types of controls on each of the unique engines in its fleet, it simply cannot evaluate whether this is a viable control strategy.

Accordingly, commenter (0554) asks the EPA to consider a possible exception, particularly for 1960-vintage units and earlier, in the form of a site-specific emissions limit based on testing following installation of the controls upon which the EPA has based its proposal. That approach is appropriate because neither commenter (0554) nor the EPA can determine at this time whether the proposed limit is achievable by such engines.

Response:

As described in Section 2 of the *Final Non-EGU Sectors TSD* and as discussed in Section VI.C of the preamble to the final rule on implementation of emissions reductions for engines used in pipeline transportation of natural gas, the EPA is finalizing NO_X emissions limits for natural gas fired four stroke rich burn, natural gas fired four stroke lean burn, and natural gas fired two stroke lean burn engines, as proposed. These final limits are based on the information the EPA reviewed for engines used in the pipeline transportation of natural gas industry, which included state and local regulations applicable to similar engines, and current Title V permits issued to facilities with these types of engines.

Specifically, the 1.0 g/hp-hr NO_X emissions limit the EPA is finalizing for four stroke rich burn spark ignition engines is expected to be met with NSCR, or a combination of other control measures. The 1.5 g/hp-hr NO_X emissions limit the EPA is finalizing for four stroke lean burn spark ignition engines is expected to be achievable via SCR, or a combination of other control measures. Two stroke lean burn spark ignition engines are expected to meet the final 3.0 g/hp-hr NO_X emissions limit by installing layered combustion controls or a combination of other control technologies. The technologies that are the basis for the final rule limits are demonstrated and proven cost-effective in this industry. Owners and operators are not required to use a specific control technology and can choose any control that meets the applicable emissions limit.

To the extent owners and operators of specific types of engines do not believe they will be able to meet a particular emissions limit, the EPA is including a flexibility provision in the final rule that allows affected facilities to utilize emissions averaging. This provision will enable owners and operators to implement a facility-wide averaging plan approved by the EPA, where owners and operators can determine which engines to control and to what level. 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. The preamble to the final rule (see section on Implementation of Emissions Reductions) indicates that facility-wide emissions averaging provision is estimated to allow facilities to install controls on only one-third of their engines.

For the reasons provided above, despite uncertainties that commenters cite regarding controls, certain types of engines, and engines of a particular vintage, the EPA has concluded that the only exemption that is justified for this industry is the exemption for emergency engines.

Exemptions

Comments:

Commenters (0371, 0554,) strongly encourage the EPA to exclude emergency engines in the final rule. Doing so would not only be consistent with other regulations applicable to RICE, but it would also be more consistent with the EPA’s applicability analysis, which assumes RICE will operate for 7,000 hours a year, something emergency engines are prohibited from doing by federal regulation. Currently, emergency generators are exempt from requirements applicable to non-emergency RICE under both relevant NSPS (subparts IIII and JJJJ), as well as the relevant NESHAP (subpart ZZZZ). And for good reason—the units are only authorized to operate for 100 hours per year for maintenance, readiness testing, and other non-emergency purposes. Although the standards the EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, the EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the "PTE" in issuing air permits for emergency RICE.

Commenter (0782) recommends that the following types of engines be exempt from the proposed requirements for stationary SI engines, similar to the exemptions in Colorado's regulations on engines: nonroad engines; emergency power generators that operate less than 250 hours per year on a rolling 12-month basis; internal combustion engines subject to an emissions control requirement under a MACT standard, a BACT limit, or a NSPS limit. The commenter further recommends that the EPA exempt non-emergency engines that operate less than 1,000 hours per year on a rolling 12-month basis, as requiring installation of emissions controls on low operating engines would not be cost-effective.

Commenter (0554) continues, RICE that qualify as emergency engines under other currently applicable standards only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, their emissions are low and accordingly, their contribution to the ozone transport issues the EPA's proposal seeks to address is negligible. Pipeline engines that qualify as emergency RICE under subparts JJJJ or ZZZZ should be excluded from the final rule entirely. Alternatively, if the EPA remains concerned with the level of operation of emergency RICE during ozone season, BHE asks the EPA to allow only limited operation of emergency engines during the ozone season for purposes other than an emergency.

Commenter (0554) asks the EPA to include provisions in the final rule to confirm that RICE subject to an enforceable requirement that prohibits operation during the ozone season are excluded from the ozone transport rule. Commenter (0554) and many of its counterparts in the pipeline transportation of natural gas industry operate some RICE that would be subject to the proposed rule based on their size even though they only operate during the winter months and do not operate at all during the ozone season. These winter- peaking units operate only to meet demand on extreme winter system demand days. Since winter- peaking RICE do not operate during the ozone season, owners and operators of these engines should not be subject to limits designed to reduce NO_X emissions during the ozone season.

Response:

The EPA has reviewed information submitted by commenters on the proposal, looked at comparative regulations, and agrees with comments that stationary emergency engines should be exempt. As such, and for consistency with the EPA's general treatment of emergency engines in other CAA rulemakings, the EPA is exempting emergency engines from the requirements of the final rule. We explain our rationale for this exemption in Section VI.C of the preamble. The final rule (at § 52.41(b)(1)) specifies the circumstances under which a stationary engine would be classified as an emergency engine.

In terms of engines with lower usage, the EPA recognizes that in some cases installing controls on these units may not be cost-effective. In response to comments on lower-use engines, the EPA is including a provision in the final rule (at § 52.41(d)) that allows a source owner/operator to seek EPA approval of a facility-wide averaging plan that would allow the owner or operator to determine which engines to control and to what level. 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.

Emissions Averaging

Comments:

Commenter (0782) suggests that the EPA should also consider whether a fleetwide or company-wide alternative compliance plan, similar to what is used in Colorado, is appropriate to adopt. The commenter relates that a fleetwide or company-wide plan requires an overall emissions percentage reduction based on fleetwide or company-wide engine operations, and owners and operators using this alternative plan must demonstrate that total NO_X emissions allowed under the plan are less than or equal to the total NO_X emissions allowed through compliance with the emissions standards on an individual engine basis. The commenter states that this type of alternative compliance plan affords owners and operators with the flexibility to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emissions reductions than would be achieved through compliance with the emissions standards on an individual engine basis.

Commenters (0330, 0350, 0380, 0554, 0501) recommend that the 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. The EPA, INGAA, and other stakeholders including commenters (0380, 0501) 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 the EPA evaluated and supported reliance on emissions averaging for RICE in the natural gas pipeline sector. The commenter states that the 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 NO_X reductions. As the EPA had recommended, many states built their revised SIPs around the emissions averaging approach that the EPA advocated for in the model rule.

Commenter (0350) asks that the EPA establish emissions targets for each state and should publish a model rule (with core elements established/used by existing successful programs) and allow states to exercise their discretion to implement the model rule or other cost-effective and technically feasible rules through SIP implementation. The commenter provides a brief background on the development of the 1998 and 2004 NO_X SIP Call, and generally believes that the approaches taken under the NO_X SIP Call provided states and regulated entities with the flexibility needed to comply with the emissions reduction requirements – 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, and the averaging approach provided relief from the difficulty of having regulators and facilities agree on technical definitions, 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.

Commenters (0380, 0501) provide state-specific factors to consider in emissions averaging:

Pennsylvania has adopted emissions averaging provisions to address NO_X and volatile organic compounds for purposes of RACT, and the EPA has approved those provisions. Alternative NO_X RACT emissions limits include facility-wide or system-wide NO_X 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 the EPA agreed, that those emissions reductions under the averaging plans would be equivalent to emissions if the individual sources were operating in accordance with the applicable presumptive limit. Accordingly, the 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 emissions averaging rules. New York's rules require emissions averaging plans to employ a weighted average permissible emissions 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 emissions standards through the EPA-approved emissions averaging plans. Ohio's rules require that emissions 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 emissions reductions must be equal to or greater than the actual emissions 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 emissions 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 equivalent or greater emissions increase and that the reduction accounts for any increase in NO_X emissions from other sources as a result of the shutdown."

Texas has allowed emissions averaging to demonstrate compliance with its emissions 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 percent reduction of the hourly emissions rate of NO_X and affected engines in West Texas to achieve up to a 20 percent reduction of the hourly emissions rate of NO_X. 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 to demonstrate" the required reductions. 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.

Illinois allows owners and operators of affected RICE units to comply with NO_X emissions limits through an emissions averaging plan. Illinois follows the EPA model rule, and the Illinois EPA rule provides equations by which owners and operators must demonstrate that total mass of actual NO_X emissions from the units listed in the emissions averaging plan are equal to or less than the total mass of allowable NO_X emissions for those units for both the ozone season and calendar year.

In addition to these and other states, the OTC developed NO_X RACT technical guidelines for RICE used in natural gas transmission and included emissions averaging in those guidelines. The OTC guidelines provide emissions 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 NO_X reductions that would be achieved if all of the units at the location met the applicable NO_X emissions limitations of the guidelines.

Commenter (0554) recommends that the EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company, as allowed under similar EPA and state programs. For example, in the NO_X SIP Call, the EPA encouraged states to allow owners and operators of large internal combustion engines the flexibility to achieve the required NO_X tons/season reductions by selecting from among a variety of technologies or combinations of technologies, recognizing that "flexibility would be helpful as companies take into account that individual engines or engine models may respond differently to control equipment." The EPA acknowledged that "some individual engines that install the controls would be expected to be above and some below the average control level, simply because it is an average." States have successfully incorporated NO_X emissions averaging into their own rules for pipeline RICE as well.

Commenter (0554) continues, since the emissions limitations in the proposed rule are expressed in g/hp-hr, the calculation of an intra-state fleet-wide NO_X limit with a weighted average for different unit types should be relatively straightforward. The EPA should also consider whether to allow companies to choose a mass-based alternative that would ensure emissions reductions align with the tpy reductions upon which the EPA based its significant contribution and over-control analyses. Either approach would allow companies to choose, based on the individualized characteristics of the units within their fleets, how best to accomplish the emissions reductions that are required to eliminate their state's significant contribution to downwind air quality issues. Given that the EPA's analysis of how to eliminate those downwind contributions is made on a state-wide basis, rather than on emissions from individual units, BHE urges the EPA to recognize that intra-state emissions averaging and the compliance flexibilities it offers to an industry composed of heterogenous engines is appropriate in the context of the EPA's ozone transport rule.

Response:

The EPA agrees with these comments about the need to offer additional compliance flexibility through facility-wide averaging plans and a provision for these has been added to the final rule (see § 52.41(d) of the final rule). This approach allows an owner or operator of multiple units at a single facility to control NO_X emissions consistent with the final rule in a manner that is most cost effective. The EPA acknowledges that control of some units (e.g., those operated at high-capacity levels and/or have higher emissions rates) will be more cost effective than others (e.g., secondary or back-up units). The facility-wide averaging plan requires the owner or operator to establish a daily emissions cap that must be maintained on a 30-day rolling average. The daily emissions cap is determined from the highest 30-days of operation during the ozone season from each affected unit, the design capacity of each unit, and the applicable emissions limit. During the ozone season, facility operators are required to monitor the 30-day rolling average of daily emissions for all affected units to assure that emissions remain below the cap. 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 limits, the covered units will be in compliance with the emissions limits in § 52.41(c).

Additionally, the final rule contains a provision allowing sources to request EPA approval of limited compliance extensions beyond the 2026 ozone season, where specific criteria are met, and a provision allowing sources to request EPA approval of case-by-case emissions limits based on a showing that an affected unit cannot meet the applicable emissions limit due to technical impossibility or extreme economic hardship. We describe these provisions more fully in Section VI.A.2 and Section VI.C of the preamble. We respond to comments about control installation timing needs for non-EGU industries in Section VI.A.2 of the preamble, and we respond to comments about potential overcontrol in Section V.D.4 of the preamble.

> As explained in the proposal, the EPA found that most RACT rules and other standards reviewed by the EPA established applicability for engines based on design capacity rather than PTE. To be consistent with established requirements for engines, the EPA selected a design capacity of 1,000 braking horsepower (bhp) for engines to capture the same size units identified in Step 3 of our 4-step interstate transport framework. Based on the Non-EGU Screening Assessment memorandum, engines with a PTE of 100 tpy or greater had the most significant potential for NO_X emissions reductions.

5.3.1.3 Monitoring, Recordkeeping, and Reporting

Comments:

Commenters (0300, 0501) states that in the proposed Section 52.41(d)(1), the cross-reference to paragraph (b), should be paragraph (c). Commenter (0501) also states that the proposed Section 52.41(d)(2)(B), the cross-reference to paragraph (b) should be paragraph (c).

Response:

The final regulatory text reflects these changes.

Comment:

Commenter (0301) states that 40 CFR 52.41(d)(2)(i) refers to engines meeting the certification requirements of 40 CFR 60.4243(a) under subpart JJJJ. It is unclear how a regulation for NO_X from engines of 1,000 hp or more can refer to a certification process that has differing compliance dates, does not specifically address certification with NO_X standards, and addresses engines much smaller than 1,000 hp.

Response:

The final rule includes an exemption for certain new engines that are subject to lower NO_X emissions limits under 40 CFR part 60, subpart JJJJ than the final FIP emissions limits. Since these engines are no longer affected engines, the EPA has also removed the certification language previously under 40 CFR 52.41(d)(2)(i).

Comment:

Commenter (0353) believes the proposed compliance requirements appear to be arbitrarily selected and are inconsistent with existing requirements under the NSPS subpart JJJJ and the NESHAP subpart ZZZZ. According to the commenter, under the existing subpart JJJJ regulations, owners and operators of Stationary Engines that are not being operated and maintained in accordance with the manufacturer's certification must utilize a maintenance plan, keep maintenance records, operate the engine in a manner consistent with good air pollution practices, and undertake performance testing once every 8,760 hours or three years (40 C.F.R. § 60.4243(a)(2)(iii)). The commenter states that the proposed rule does not acknowledge these existing compliance requirements or explain why the EPA finds that significantly more stringent compliance requirements are now necessary. According to the commenter, although the EPA may change its policy on what is necessary to demonstrate compliance, it must identify the factual findings justifying that change and provide a satisfactory explanation in support.

Response:

Owners or operators of affected units under § 52.41 of the final rule have different monitoring, reporting and recordkeeping requirements depending on whether they elect to apply controls to each affected unit or obtain EPA approval of a Facility-Wide Averaging Plan.

Owners and operators electing to apply controls to each affected unit, as specified in the §52.41 Testing and Monitoring section, must implement a maintenance plan containing elements consistent with the maintenance plan requirements of 40 CFR part 60, subpart JJJJ and 40 CFR part 63, subpart ZZZZ. Only new or existing affected engines have additional performance test requirements beyond those in the NSPS or NESHAPS regulations (i.e., an initial test and subsequent annual testing). Since these engines were never certified to meet the NSPS limits, they may not achieve the emissions limits for the final rule even with added controls. For these engines (and the associated control equipment), lacking any manufacturer certification that the emissions limits can be retained with proper maintenance, the EPA finds that annual performance testing is needed to confirm ongoing compliance. Note that for SCR or NSCR controls, the final rule also requires daily temperature monitoring of the inlet to the catalyst, as well as monthly monitoring of pressure drop across the catalyst.

For owners or operators that do not use SCR or SNCR, a continuous parameter monitoring system (CPMS) is required along with a site-specific monitoring plan. The CPMS needs to log readings at least once every 15 minutes, and the performance of the CPMS must be evaluated annually. In lieu of a CEMS, the CPMS and monitoring plan is needed to assure that the engine is operating in a manner consistent with its initial performance tests which indicated compliance with the applicable emissions limits of the final rule.

For owners or operators that elect to comply using a facility-wide averaging plan, the same testing and monitoring requirements exist as those for owners/operators applying controls to each affected engine (initial performance test within six months of being subject to the final rule and every twelve months thereafter). This includes engines that are not being controlled under the facility-wide averaging plan. This flexibility provision of the final rule (facility-wide emissions averaging) is not a component of the NSPS or NESHAPS; and the annual testing is needed to assure compliance with the facility's calculated emissions cap.

Comments:

Commenters (0289, 0508) recommend that the EPA include an exemption to the testing requirements for units that do not operate or that only operate a small number of hours during the ozone season. According to the commenters, the demand for natural gas is highest during the winter months when ozone issues are of no concern, and it is highly unlikely that units in the natural gas transportation industry would need to operate during the summer months when the new emissions rates in the regulation apply.

Commenter (0508) adds operators of affected Pipeline emissions sources would be required to submit electronic copies of required performance test reports, performance evaluation reports, quarterly and semiannual reports, and excess emissions reports through the EPA's various electronic data management systems that fall outside the ozone season. If the proposed rule only applies during the ozone season, they request the EPA's proposed rule limit the requirements (emissions limits, compliance requirements, testing, reporting information, etc.) for pipeline emissions sources to the ozone season.

Response:

In response to these comments, in the final rule the EPA is including the following in §52.41 Testing and Monitoring Requirements.

> "If you are the owner or operator of an engine that is only operated during peak periods outside of the ozone season and your hours of operation during the ozone season are 50 hours or less, you are not subject to the testing and monitoring of this paragraph so long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g)."

Note, an initial performance test will be required but these units would be exempt from further continuous compliance testing.

Also note that for the final rule, the emissions limits must be met on a 30-day rolling average basis during the ozone season (§ 52.41 Emissions Limitations Section). Similarly, for owners/operators that comply with the rule using a facility-wide averaging plan, a demonstration of compliance with the emissions cap must be done on a 30-day rolling average basis only during the ozone season (see § 52.41(d), Facility-Wide Averaging Plans).

Comments:

Commenter (0330) recommends amending Section § 52.41(d)(2) to specify the unit testing operating conditions. For example, they would propose the following language or something similar: “The test must be conducted at any load condition within ±10 percent of 100 percent achievable load”. Also, for units equipped with SCR or NSCR (SNCR), the test should not set the allowable temperature range, as this could be far narrower than the actual vendor recommendation. Instead, verification that the temperature is within the proper operating range should be required during testing.

Commenter (0300) suggests allowing the consideration of seasonal fluctuations or other variables for compliance with a temperature range [40 CFR 52.41(d)(3)(i)]. The commenter states a performance test cannot be expected to capture the temperature range of inlet gases that would still meet the proposed NO_X emissions limitation, and it is unprecedented to not allow for some variation in inlet temperature (*e.g.*, ±50 degrees Fahrenheit) or otherwise allow for compliance with a temperature range specified by the SCR or NSCR manufacturer.

Response:

The final rule specifies that the applicable reference test methods of 40 CFR part 60, appendix A are to be used to demonstrate compliance (or alternative test method approved by the EPA). 40 CFR part 60, subpart JJJJ requires that the tests be conducted within 10 percent of 100 percent of achievable load. For engines that are not operating CEMS, establishing parametric monitoring ranges unique to each unit is paramount to effective parametric monitoring in place of direct emissions measurements. However, for units that are not required to conduct a performance test, the final rule allows for the use of manufacturer temperature ranges to be used for SCR and NSCR.

Comment:

Commenter (0334) believes that any engines already subject to such requirements via NSPS requirements should be exempt from any new requirements that would be imposed by this proposed rule. Compliance with NSPS monitoring, reporting, and recordkeeping requirements should be sufficient for purposes of this proposed rule. The EPA has not provided any sort of analysis or justification as to why monitoring, reporting, and recordkeeping requirements that are currently imposed upon pipeline engines via NSPS rules would not be adequate in the current context to achieve the purposes of the FIP.

Response:

The EPA has modified the language in § 52.41 Applicability Section to exclude engines that are already complying with equivalent or more stringent limits in the NSPS. Engines meeting these criteria would not be subject to the FIP and would not need to conduct any monitoring, recordkeeping, and reporting.

- 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, you do not have to comply with the requirements of this section.
- 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, you do not have to comply with the requirements of this section.

Engines not subject to these equivalent or more stringent NSPS requirements, are subject to the emissions limits in the final rule. For those engines, the monitoring and recordkeeping requirements in the final rule are needed to assure ongoing compliance with the 30-day rolling average emissions limits or facility-wide emissions averaging plan provisions (see Testing and Monitoring Requirements and Recordkeeping Requirements in § 52.41). To the extent a particular monitoring or testing requirement is also required by another applicable rule, like the NSPS, the EPA encourages owner and operators of affected units to work with their permitting authorities streamline compliance with these requirements. Furthermore, the EPA notes that if a source is already conducting an annual performance test on an engine to verify compliance with another requirement, that source can use that annual performance test to satisfy the performance test requirement at § 52.41(e)(3)(iv) in the final rule (as long as it meets the testing requirements of § 52.41(e)(3)(iv)).

Comments:

Commenter (0350) notes performance testing on a single unit can cost upwards of $5,000 per test. Testing commenter's (0350) approximately 950 units twice a year would therefore cost approximately $9.5 million annually, with a portion of additional costs passed on to consumers in the form of higher energy prices, without a corresponding environmental benefit.

Commenter (0554) adds 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. The EPA expressly acknowledges that monitoring, testing, and recordkeeping costs are not reflected in its $7,500/ton control cost estimates, confirming it has not taken the substantial costs of demonstrating compliance into account, despite the focus on cost-effectiveness as the key factor in determining the scope and stringency of the proposed rule. Commenter (0554) continues, the EPA cites a total estimated cost of $11.45 million for monitoring, testing, and compliance at all affected non-EGU sources across several different industries. Based on BHE's assessments regarding the potential costs for its own fleet, commenter (0554) believes this estimate to be well below actual costs to be borne by the pipeline industry alone. Commenter (0554) estimates that the cost to design and install CEMS on a single engine would be about $350,000, which does not include ongoing costs for operation and maintenance of the system or costs for consumables, like calibration gas, that are necessary for operation of the system.

Response:

The final rule does not require the use of CEMS to demonstrate compliance with the emissions limits, but it does allow for their use if installed (§ 52.41 Testing and Monitoring Requirements Section). Performance tests are required annually after an initial test to be conducted within six months of rule finalization. Units that are subject to the NSPS are exempt from the emissions limits and monitoring requirements of the final rule. However, the EPA is requiring more frequent monitoring and testing than the NSPS for other engines, because the EPA is not necessarily regulating new engines and is setting limits on many older engines. Those older engines need to have more frequent testing and monitoring to ensure that they are meeting the emissions limits of the final rule (newer certified engines, by contrast, have manufacturer guarantees on emissions).

Comment:

Commenter (0350) remarks that testing is operationally demanding, but the proposed rule neglects this reality. The commenter states that as an example, the EPA regulations require units to be tested when the load is between 90–100 percent of the maximum load, which is a state that may not occur naturally. The commenter remarks that it is an intensive process in both labor and time to artificially increase the load prior to testing and is more complex the greater the load must be increased from natural conditions to 90 percent. The commenter states that due to this factor, flexibility in testing timing is of paramount importance. The commenter also asserts that to test all of its 950 units, a minimum of 12 months would be needed rather than the proposed 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). The commenter adds that in the past, the EPA has accounted for these operational realities, noting that under the NSPS and NESHAP, testing is generally required only for every 8,760 hours of run time, and the commenter asserts that there is no reason to impose more frequent testing requirements than that under the NSPS and NESHAP.

Response:

Testing requirements are consistent with prior EPA requirements for engines and consistent with RACT testing requirements. For instance, 40 CFR part 63, subpart ZZZZ § 63.6620(b) states:

> “The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section."

40 CFR part 60, subpart JJJJ § 60.4244(a) states:

> “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 specific conditions that are specified by Table 2 to this subpart.”

In the final rule, the EPA has specified that performance testing must occur once annually, and it does not have to be during the ozone season to provide sources the flexibility to schedule performance tests at different intervals. Further, based on adjustments to the definitions of an affected unit, the EPA finds that the number of affected engines will be far lower than the 950 engines cited by this particular commenter.

Units that are subject to the NSPS are exempt from the emissions limits and monitoring requirements of the final rule. However, the EPA is requiring more frequent monitoring and testing than the NSPS for other engines, because the EPA is not necessarily regulating new engines and is setting limits on many older engines. Those older engines need to have more frequent testing and monitoring to ensure that they are meeting the emissions limits of the final rule (newer certified engines, by contrast, have manufacturer guarantees on emissions).

Comments:

Commenters (0275, 0289, 0300,0330, 0334, 0359, 0380,0397, 0403, 0501, 0508 ,0554) believe CEMS would be an unnecessary cost and provide no emissions benefit for the vast majority of the non-EGUs the proposed FIP intends to control. Commenter (0300) adds that requiring subsequent testing every six months would likely require hundreds, if not thousands, of sources to be tested in a very short timeframe and on a very frequent basis. The commenter notes that many facilities have difficulties arranging for much less frequent testing and assumes that the EPA has not considered the feasibility of conducting these tests with the available resources.

Commenter (0353) responds to the EPA's request for comment on whether "it is feasible or appropriate" to require Stationary Engine owners and operators to install and operate a CEMS instead of conducting semi-annual performance testing. The commenter does not believe that either CEMS or semi-annual performance testing are appropriate due to their high costs and limited benefits. According to the commenter, the EPA has traditionally agreed with that view, as most Stationary Engines are not currently required to install or operate CEMS (see 40 CFR, part 60, subpart JJJJ, Table 3).

Commenters (0330, 0334, 0359, 0380, 0397) state that since the proposed rule is intended to address the ozone season, a single, annual test is more feasible than semi-annual testing and reporting. If the EPA retains the semi-annual testing requirement, annual reporting is still adequate for conforming sources. If anomalous test results occur, the EPA or the delegated authority could be informed of that situation through the test report submittal process. In contrast to the EPA's proposed rule, 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.

Commenter (0350) asserts that the projected upfront installation costs of CEMS are significant, and the EPA should not impose any CEMS testing requirements as part of a final rule. According to the commenter, the cost of installing such monitoring technology would be exorbitant, even outpacing the costs of retrofitting units. The commenter notes that it had to replace CEMS at a facility in 2020, incurring around $100,000 in costs just to change out the analyzers while leaving the hard lines alone. The commenter also notes that a new installation would require significant and additional resources to install electric equipment and tubing.

Commenter (0350) states that 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 to protect the analyzer from extreme ambient conditions and would need to build out a new IT framework. The commenter also notes that owners and operators would need to hire and train CEMS operators and technicians, adding ongoing labor costs and forcing companies to compete with each other to attract this scarce labor force. The commenter remarks that these costs would be in addition to the approximate annual per unit costs of $15,000 for service and $5,000 for cylinder rentals.

Commenter (0554) adds that because CEMS systems are not widely used for RICE in the natural gas pipeline industry, there are only a limited number of units available for purchase, and the commenter has determined that lead times for obtaining and installing a unit are currently about 40 weeks. Additionally, the commenter remarks that because CEMS are in limited use in the industry, there are a limited number of third-party technicians available to assist in maintenance or repair of these systems. The commenter expects that there could also be shortages of calibration gas if CEMS were implemented across the industry, given they are already experiencing extended lead times for certain calibration gases used in portable monitoring systems, as well as shortages of the small aluminum cylinders used for those gases. Additionally, the commenter notes that many RICE in the natural gas pipeline industry are located at remote, unstaffed locations, where there would be no staff available to respond and react to communication or alarms from CEMS.

Response:

Under § 52.41, Testing and Monitoring Requirements, the final rule allows for CEMS or annual performance tests and parametric monitoring to be used to demonstrate compliance with the emissions limits of the final rule. However, there is no requirement to use CEMS. For owners or operators of affected units without CEMS, the final rule requires performance testing and parametric monitoring as specified under the same section. The schedule for performance tests is annually after an initial performance test conducted within specified periods. Reporting requirements for the final rule (under the Reporting Requirements Section) require that reports be submitted within 60 days after completing each performance test (*i.e.*, annually after the initial performance test).

CEMS Exemptions

Comments:

Commenters (0380, 0501) state that low emissions combustion (LEC) is the preferred NO_X control for all lean burn engines and that once installed, LEC technology is inherent to engine operation and the combustion controls cannot be “turned off” or bypassed. The commenter note that compliant emissions are ensured by proper operation of the combustion process, and basic operating parameters can be monitored to ensure combustion health. However, the commenters note that the proposed rule requires a site-specific monitoring plan for LEC engine CPMS, and commenter (0380) recommends that the EPA defer authority for review and implementation of LEC parameter monitoring to the states.

Commenters (0380, 0501) relay that the majority of affected T&S RICE are 2-stroke or 4-stroke lean burn (2SLB or 4SLB) units, and combustion-based emissions 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. The EPA should defer lean burn engine parameter monitoring oversight to states.

Response:

Since this is a federal rule implemented by the EPA, the EPA is requiring submission of parametric monitoring to the EPA through CEDRI as is required by the NSPS and NESHAP regulations. If the EPA approves a state's SIP replacing the FIP, then the state would have the authority to implement and oversee the monitoring, recordkeeping, and reporting requirements as approved.

Comments:

Commenters (0380, 0501) also add for $SRB 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. Commenter (0380) 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.

Response:

In the final rule, the EPA is including the following in § 52.41, Testing and Monitoring Requirements, to be consistent with the varying load concerns the commenter expressed:

> (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.

As mentioned in the response to another comment about the need for monthly pressure drop monitoring across the catalyst, monitoring of pressure drop is consistent with existing RACT requirements, as well as 40 CFR part 63, subpart ZZZZ for natural gas fired engines. Therefore, the EPA is finalizing this provision as proposed.

Comments:

Commenters (0380, 0501) note the proposed rule solicits comment on using CEMS for continuous compliance monitoring. The 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. The 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 the EPA concluded that CEMS costs are too high relative to a reliable alternative: annual stack testing and/or parameter monitoring. 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.

Commenters (0380, 0501) believe these decisions are relevant because they provide an indication of consistency in the 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 emissions 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.

Commenter (0380) states the 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 the 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). Commenter (380) notes the 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 the 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. The 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. Commenter (380) concludes 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.

Commenter (0334) states the EPA's review only takes into account a small subset of the universe of engines that would actually be covered by this rule has skewed the analysis regarding the reasonableness of the proposed monitoring, reporting, and recordkeeping requirements. What might be seen as reasonable additional requirements for a few hundred engines would be far more onerous when applied to many thousands of engines. To take a case in point, the preamble asks whether continuous emissions monitoring systems (CEMS) should be required for covered pipeline engines. Putting aside the point made previously – that it is illogical in the context of ozone season FIP provisions to require year-round monitoring – it would be excessively costly, and in some cases unworkable for owners and operators of all of the many thousands of engines that would be covered by the currently proposed applicability language to install and maintain CEMS. This would also go far beyond what is needed to satisfy the "good neighbor" rule and the goals of the FIP.

Commenter (0334) notes the EPA has generally not seen fit to require CEMS for stationary engines, and there certainly is nothing in the current rulemaking record to support imposition of CEMS requirements to achieve the purposes of the FIP. The Agency has not conducted any cost / benefit analysis regarding imposing CEMS requirements here, nor is there any other sort of systemic analysis that would justify a decision to depart from traditional practice and, in the context of preventing downwind nonattainment during a few months of the summer, to require owners and operators to go to the extreme cost and burden of implementing and maintaining CEMS on the many thousands of engines that would be affected by this rule.

Response:

As specified in § 52.41 Testing and Monitoring Requirements of the final rule, CEMS is not required; however, for sources operating CEMS meeting specified requirements, CEMS data may be used instead of performance testing to demonstrate compliance.

Comment:

Commenter (0359) adds the selected control technology for 2-cycle lean burn engines is layered combustion (97 percent) with a cost of $13,100/ton of ozone season emissions. The EPA in its calculations applied annualized emissions reductions to an ozone season program to meet the established threshold. Layered combustion is the proposed control technology for 137 facilities, accounting for almost half of the Pipeline Transportation of Natural Gas facilities identified in the Screening Assessment. The EPA further proposes use of CPMS that is not included in the $13,100/ton cost analysis, making the cost estimate even higher. Given that the EPA failed to identify cost effective controls for its arbitrary and capricious proposed applicability threshold and emissions limit, this source category should be excluded from the scope of this rule.

Response:

The EPA discusses anticipated control technologies for two stroke lean burn engines in Section 2 of the Final Non-EGU Sectors TSD. In the TSD, the EPA noted that commenters have raised concerns about the proposed rule and stated that in some cases the installation of NOx controls is infeasible or cost-ineffective. Some commenters have recommended that the EPA promulgate emissions averaging provisions as a remedy. Following a review of public comments and after evaluating the results of the engine analysis conducted by the EPA, the EPA is finalizing a facility-level emissions averaging provision as an alternative means of compliance with the emissions limits established in § 52.41(c). 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. Additionally, Section VI.C.1 of the preamble discusses anticipated cost-effective controls for two stroke lean burn engines.

CEMS Alternatives

Comments:

Commenter (0300) implies that 40 CFR 52.41(d)(3)(ii) and (iii) appear to assume that an oxidation catalyst required by 40 CFR part 63, subpart ZZZZ is equivalent to a NO_X catalyst, which, according to the commenter is an absurd assumption since they are not the same catalyst materials and operate by different chemical principles. The commenter concludes that this language was likely "borrowed" from subpart ZZZZ.

Commenters (0501, 0554) support CPMS to demonstrate compliance with the emissions limitations in the proposed ozone transport rule. Commenter (0554) currently relies on parametric monitoring for many of its engines and thus has experience with that approach to demonstrating compliance. In many cases, the needed equipment and procedures are already in place. That being said, commenter (0554) requests flexibility in the parameters the EPA proposes to be monitored, as the number and type of specific parameters subject to monitoring could significantly impact feasibility and cost of the CPMS required. For units that will install SCR or NSCR, commenter (0554) understands that the EPA proposes daily monitoring of inlet temperature and monthly monitoring of the pressure drop across the catalyst, consistent with current subpart ZZZZ monitoring requirements for units subject to that standard. However, not all units are subject to the subpart ZZZZ monitoring requirements because some units comply with subpart ZZZZ through compliance with subpart JJJJ and some units are not subject to either rule. Therefore, the EPA should only impose monitoring requirements directly relevant to ensuring proper operation of the controls its proposal would require. In particular, commenter (0554) does not believe that monitoring of the pressure drop across the catalyst is relevant to the performance of natural-gas fired engines, as natural gas results in much less fouling of the catalyst than is typically experienced in diesel and gasoline-fired engines, like those regulated under subpart ZZZZ. Accordingly, the commenter encourages the EPA to limit parametric monitoring for units with SCR and NSCR to daily monitoring of inlet temperature to confirm proper operation of the catalyst.

Response:

The EPA has finalized requirements for pressure drop and temperature monitoring for NSCR consistent with 40 C.F.R. part 63, subpart ZZZZ, Table 1b (1.a). The EPA has concluded that pressure drop and inlet temperature monitoring are both appropriate and necessary to ensure that the NSCR is operating properly, as supported by the fact that similar engines have been meeting this requirement since 2010 under the NESHAP. 75 FR 9647 (March 3, 2010).

For all other controls technologies, including SCR, the final rule requires sources to develop a site-specific parametric monitoring plan under § 52.41 (e)(5).

Comment:

Commenter (0350) provides an alternative to the EPA's proposal, suggesting 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 percent of the NO_X emissions 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 percent of the NO_X emissions limit for the turbine, an operator must resume annual testing. The EPA adopted this proposal in response to comments noting that the sophisticated controls on lean premix turbines will provide consistent NO_X emissions results, just as controls anticipated to be installed at commenter's (0350) units, combined with the quality of FERC-regulated gas in the transmission sector, ensures consistent NO_X emissions results.

Response:

The final rule specifies that periodic testing be performed annually for engines not subject to the NSPS. At present, it is not clear whether the affected engines addressed by the final rule have similar performance in the field as the gas turbines brought up by this commenter.

Comment:

Commenter (0350) proposes that the 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 percent or less of permitted NO_X emissions limits. Whatever testing frequency the 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 percent or less of permitted NO_X emissions limits. The 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, 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. There is no reason not to allow Engine owners and operators flexibility to employ this proven cost-effective and reliable method of performance testing.

Response:

The final rule specifies that performance tests be conducted in accordance with: the applicable reference test methods of 40 CFR part 60, appendix A; alternative test method approved by the EPA as of the date of rule finalization 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 (§ 52.41 Performance Testing Requirements section).

Comment:

Commenter (0554) concludes for units that do not employ SCR or NSCR, the rule requires development of a site-specific monitoring plan. Commenter (0554) supports this approach since it will allow for the development of a monitoring program best-suited to each individual unit.

Response:

The final rule requires a site-specific monitoring plan for all affected units that do not employ SCR or NSCR (§ 52.41 Testing and Monitoring section).

Comment:

Commenter (0782) notes NSPS JJJJ already requires that new, modified, and reconstructed stationary SI engines greater than 500 hp conduct an initial performance test within one year of startup and subsequent performance testing every 8,760 hours or three years (whichever comes first) to demonstrate compliance with the applicable emissions standards. Commenter (0782) recommends that the EPA exempt NSPS JJJJ-applicable SI engines (new, modified, and reconstructed stationary SI engines) entirely from the rule. Having two sets of performance testing and reporting requirements for new, modified, and reconstructed engines to comply with will be unreasonably costly and duplicative, without additional emissions reduction benefits. At a minimum, Commenter (0782) recommends the EPA revise the proposed performance testing requirements and reporting requirements applicable to both new and existing stationary SI engines to align with the requirements of NSPS JJJJ. Alignment with NSPS JJJJ will provide consistency with existing federal requirements and ensure consistency between new and existing engines for easier implementation. A second alternative could be step-down testing 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 that year if the first performance test demonstrates an engine is not meeting its required emissions standards. Step-down testing will serve the purpose of verifying that an engine is meeting the requirement emissions standards and remove the need for unnecessary and costly semi-annual performance testing.

Response:

The EPA agrees with these comments. In the final rule, engines that are subject to and in compliance with 40 CFR part 60, subpart JJJJ are exempted if they are natural gas fired two stroke lean burn spark ignition engines manufactured after July 1, 2007, or if they are natural gas fired four stroke lean or rich burn spark ignition engines manufactured after July 1, 2010.

Comment:

Commenter (0501) recommends amending this section to add a direct citation of applicable NO_X methods and approved alternatives for units subject to the EPA's NSPS for spark-ignited RICE, 40 CFR, part 60, subpart JJJJ. Amending the proposed rule to include this list of accepted NO_X 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. For NO_X measurement, this includes:

- Method 7E of 40 CFR part 60, appendix A-4
- American Society of Testing and Materials (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

Response:

The EPA is including the following text in the final rule for applicable NO_X test methods. The language is consistent with other industry regulations to ensure that all available approved test methods at publication of this final rule can be used in performance tests:

> (iii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 CFR part 60, appendix A, any alternative test method approved by the EPA as of [INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER] 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 NOx emissions limit in

paragraph (c), the emissions rate shall be calculated in accordance with the requirements of 40 CFR 60.4244(d).

5.3.2 Cement and Concrete Product Manufacturing

5.3.2.1 Applicability Threshold

Potential for Additional Emissions Reductions

Comments:

Commenters' (0235, 0295, 0237) facilities currently have, at the minimum, RACT and in many cases BACT or BARCT. Historically, commenters (0235, 0295) have found that additional controls/requirements added to facilities already equipped with RACT, BACT or BARCT do not gain the amount of emissions reductions estimated due to operational factors inherent in the preexisting and pre-controlled equipment. The commenters state that the specific methods to achieve RACT, BACT or BARCT control levels are highly variable depending upon the facility in question. The commenters (0235, 0295) are concerned that without a robust analysis of to each potentially affected facility, the estimated emissions reductions as expressed in the proposed FIP would not be realized.

Response:

We respond in Section 2.2.5 (Comments that Facilities are Already Well-Controlled) to comments claiming that non-EGU sources that are already well-controlled should not be subject to the FIP. We respond in Section 2.2 (Non-EGU Industry Screening Methodology) to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluation of potential emissions reductions from these industries (including claims that the EPA has overstated the potential emissions reductions from non-EGU industries), and evaluation of related control costs.

Affected Cement Plant Estimates

Comments:

Commenters (0237, 0303) state there is inherent inequity in applying the cement kiln limit in California because three of the six Southern California cement plants have consent decrees. The commenters state that 50 percent of the cement kilns are excluded from the rule (because of consent decrees), and it does not make sense to apply a rule to 50 percent of the plants and not to the other 50 percent of plant in the same general location. According to the commenter, kilns with consent decrees will not be subjected to source cap limits, even though source cap limits (which are location-specific) need to be based on a comparison of total emissions pre-rule to a total emissions limit.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0359) adds that the increased number of units that may need some sort of controls under this rule causes concern that all units may not be able to install controls by 2026 due to competition for vendors as well as the time needed for permitting actions. The commenter notes that its air permitting sections have few resources available to devote to this new work, and priority for permitting resources must be given to new construction.

Response:

The EPA has responded to these comments in Section VI.A.2 of the preamble. The EPA also initiated a study to examine the time necessary to install controls at non-EGU industries and, in Section VI.A.2 of the preamble, describes the key findings and underlying assumptions in the resulting report entitled SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023).

Comment:

Commenter (0525) adds that the EPA has failed to provide provisions for semi-dry kiln types, as well as failed to identify semi-dry, long dry, and preheater kiln types in the Source Cap Limit formula. Without fully understanding the limits proposed and how those limits might impact operations with these kiln types, the commenter claims that they cannot fully assess impacts and develop comments related to these aspects of the proposed rule.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Applicability Must Be Based on Detailed Analyses

Comments:

Commenter (0347) states the proposed FIP is internally contradictory in that it asks for comment on the feasibility of phasing out long wet kilns and replacing them with lower-emitting units like preheater/precalciner installations, but the EPA also states that conversion from long wet kilns to preheater/precalciner installations is generally feasible. According to the commenter the EPA cannot, without any meaningful analysis and evaluation, conclude that converting long wet kilns to a different installation is feasible. The commenter states that doing so would "outlaw" existing manufacturing technology without meaningful NO_X emissions reductions. The commenter notes that the EPA’s statement that that replacements of long wet kilns with preheater/precalciner kilns is generally feasible is based on what appears to one example at a cement plant in Texas that agreed to retire two of its three kilns as part of a federal CAA consent decree. According to the commenter, the company's agreement to the retrofit was likely done because it was economically viable and made sense for the company to resolve the pending CAA violation allegations. The commenter states that the EPA should not base a wet-to-dry cement kiln replacement regulatory feasibility determination on one example that was agreed to in and required by a federal consent decree. The commenter adds that unlike this company, the commenter's facility does not have the option of shifting production to another plant to undertake any conversion or retrofit process, and a requirement to convert wet kilns to preheater/precalciner kilns would effectively be a shutdown mandate and evaluation is not feasible for a company like the commenters'.

Response:

As explained in Section VI.C.2 of the preamble, the final rule does not contain any requirement to replace or phase out existing long wet kilns.

Comment:

The commenter adds that its operations are an excellent example of why a wet-to-dry conversion requirement likely would result in more NO_X emissions in downwind states. The commenter states that the annual NO_X emissions from its kilns are among the lowest for the cement kilns the EPA analyzed as part of the proposed FIP and are nearly an order of magnitude less than annual NO_X emissions for certain preheater/precalciner kilns evaluated by the EPA. According to the commenter, requiring replacement or retrofitting of wet kilns invariably would result in replacement of such kilns with larger and higher-producing, preheater/precalciner kilns. The commenter says that if it could afford to replace the wet kilns with preheater/precalciner kilns, it would need to significantly increase the production capacity to make the investment economically viable. Moreover, the commenter questions whether it is even technically feasible to build a preheater/precalciner kiln equivalent in capacity to the existing small wet kilns currently operated at its Pennsylvania plant.

Response:

As explained in Section VI.C.2 of the preamble, the final rule does not contain any requirement to replace or phase out existing long wet kilns.

5.3.2.2 Emission limits

Comment:

Commenter (0300) recommends that the EPA either include Equation 6 of 40 CFR 60.64(c)(1) under 40 CFR 52.42(d) or reference it only; noting it is not necessary to do both.

Response:

The EPA disagrees with the claim that including both the reference and equation itself is unnecessary.

Comment:

Commenter (0505) continues, the EPA's proposed emissions limits for Cement and Concrete Product Manufacturing sources apply to all cement kilns in Texas based on the kilns' actual and/or permitted NO_X emissions of 100 tpy. However, the EPA included only 12 of the existing 15 cement kilns in Texas in its NO_X emissions reductions analysis. It is unclear why the EPA excludes from the analysis three cement kilns located in Bexar, Comal, and Ellis Counties. The EPA also does not account for all existing kiln NO_X controls and has therefore overestimated the amount of available NO_X emissions reductions from Texas cement kilns and inaccurately assessed the availability of cost-effective controls. In Texas, 14 of the 15 cement kilns are already equipped with SNCR; however, the EPA assumed that no cement kilns in Texas are equipped with SNCR. In addition, some Texas cement kilns have other existing controls such as low-NO_X burners that are not included in the EPA's analysis. Finally, the EPA did not consider that the majority of Texas cement kilns (nine of 15) are already permitted below the proposed emissions limits for their kiln type, rendering additional NO_X emissions reductions unlikely. The commenter notes potential NO_X emissions reductions during the ozone season are less than the EPA stated when the cement kilns that are already meeting the proposed emissions limits based on TCEQ permit requirements are excluded.

Response:

The EPA reviewed title V permits for affected cement plants and has updated the list of cement plants and NO_X control devices included in our emissions reduction analyses. See Memorandum dated March 15, 2023, *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*. In addition, we respond in Section 2.2 (Non-EGU Industry Screening Methodology) to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluation of potential emissions reductions from these industries (including claims that the EPA has overstated the potential emissions reductions from non-EGU industries), and evaluation of related control costs.

A Different NO_X Standard Is Appropriate for Cement Kilns

Comment:

Commenter (0516) states the proposed limits would impose infeasibly stringent NO_X emissions limits on the cement industry and would result in kilns having to curtail production or shut down. According to the commenter, existing domestic cement production does not meet current demand, which is expected to only increase as federal and state governments allocate more money for infrastructure spending. The commenter states that if finalized, the rule will significantly impact the industry's domestic manufacturing capacity, reducing U.S. economic growth, preventing the industry from returning to peak production levels, and resulting in the import of more cement from overseas, which could result in worse environmental outcomes, including increased GHG emissions.

Response:

We disagree with the commenter's claim that the emissions limits for the cement industry are infeasibly stringent. We provide our rationale for the emissions limits we are establishing for this sector in Section VI.C.2 of the preamble and Section 3 of the Final Non-EGU Sectors TSD. Additionally, as explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0758) states that not only are the proposed limits achievable, but they should be strengthened. The commenter relays that according to the OTC, all states in the OTR with cement kilns already have more stringent limits in place for long wet kilns, preheater kilns, and precalciner kilns. The commenter notes that cement kilns are large emitters of NO_X pollution and are often concentrated in or near communities of color and economically marginalized communities, also recounting that cement kilns with annual emissions greater than 100 tons in the 23 covered states will emit 36,000 tons of NO_X during the ozone season, which is more than any state but one's 2023 EGU ozone-season NO_X budget and more than any other considered non-EGU sector. The commenter notes that the proposed limit for long dry kilns is 3.0 lb NO_X/ton of clinker, but some facilities, such as Ash Grove, is subject to a limit of 1.5 lb NO_X/ton of clinker, and Texas industries has a permitted emissions factor of 1.95 lb NO_X/ton of clinker. The commenter states that these limits show that lower limits than what the EPA proposes are achievable, and the EPA should strengthen its proposed limits applicable to dry kilns. The commenter continues, noting that for preheater kilns, the EPA proposes a limit of 3.8 lb/ton of clinker, based on Texas and Illinois state standards, however, Maryland and Pennsylvania have more stringent standards of 2.4 and 2.36 lb/ton of clinker in place. The commenter further remarks that for precalciner kilns, the EPA proposes a NO_X limit of 2.3 lb/ton of clinker, yet the NSPS sets a limit of 1.5 lb/ton of clinker based on the application of SNCR technology.

Response:

The EPA recognizes that many cement kilns are subject to requirements more stringent than those contained in this final rule but has concluded that the emissions limits in this final rule are adequate to eliminate significant contribution from this industry for purposes of the 2015 ozone NAAQS. We provide our rationale for the emissions limits we are establishing for the cement industry in Section VI.C.2 of the preamble and Section 3 of the Final Non-EGU Sectors TSD.

The commenter fails to substantiate its claim that the EPA should or must establish more-stringent emissions limits reflecting operation of SCR controls at existing cement kilns. Commenter appears to advocate use of SCR noting an 80 percent NO_X control and references its installation at a source in Joppa, Illinois to support its claim that EPA should promulgate an emissions limit of 1.5 lb/ton or an even lower level. The EPA reviewed title V permits issued to cement plants in all affected states during development of this rulemaking action. Our review of the air permit for the Joppa Illinois plant reveals that the NO_X emissions limit for kiln #1, which is equipped with SCR, is 3.21 lb/ton of clinker on a 30-day rolling average basis. Furthermore, kiln #1 is an existing unit (originally constructed 1960) and is not subject to the federal NSPS which limits NO_X emissions to 1.5 lb/ton of clinker.[81],[82]

With respect to dry kilns the commenter states that the EPA's proposed limit of 3.0 is not stringent enough, citing the dry kiln operated by Ash Grove in Ellis County, Texas, which is subject to a limit of 1.5 lb/ton of clinker. This facility, however, was subject to a 2013 consent decree with the EPA that required the shutdown of two kilns by September 10, 2014 and reconstruction of kiln #3 with SNCR with an emissions limit of 1.5 pounds of NO_X per ton of clinker, consistent with the applicable NSPS for Portland Cement Plants. The NSPS for Portland Cement plants applies to affected sources that commence construction, modification, or reconstruction after June 16, 2008. Unlike kiln #3 at the Ash Grove facility, many of the cement kilns subject to this final rule were constructed, modified, or reconstructed long before June 16, 2008 and are not subject to the NSPS emissions limit.

A large number of EGUs over the last 25 years has successfully applied SCR technology to mitigate NOx emissions. The suppliers' knowledge of SCR design and supply regarding the EGU fleet has become a mature technology capable of reducing NOx emissions involving the various operating conditions, fuels, and equipment encountered specific to the EGU sector for producing high pressure, high temperature steam to generate electricity. The cement kiln industry, while utilizing similar fuels (coal-fired), faces a different set of challenges since the process manufactures clinker product. For all of these reasons, the final rule does not require installation of SCR at cement kilns.

Comments:

Commenters (0235, 0295, 0513, 0516) note that the proposal specifically mentions SCR or SNCR as potential add-on control measures for Portland Cement Kilns, however the terminology, definitions and discussions of such measures do not appear to be internally consistent, and it is unclear exactly which technologies the EPA is contemplating. Commenters (0235, 0295) have found there is a constant problem with ammonia using such systems to achieve the required NO_X control without releasing excess ammonia into the atmosphere (commonly referred to as "Ammonia Slip"). The commenters point out that ammonia is a HAP and many of the secondary compounds formed in the exhaust stream are also HAP. The commenter state that this has the potential to increase the toxic risk on potentially already environmentally burdened communities directly downwind. These commenters are concerned that to achieve the levels in the proposed FIP, the secondary pollutant formation could have unexpected and negative impacts on the attainment status for $PM_{2.5}$.

[81] State of Illinois Clean Air Act Permit Program (CAAPP) Permit No. 95090119, issued to Joppa Plant 2500 Portland Road Grand Chain, IL 62941, "Nitrogen Oxide Requirements (NOx)" Section (i)(B), at pdf Page 42 of 122.

[82] LAFARGE – JPA-K1-SCR, U.S. EPA Consent Decree Final Demonstration Report.

Response:

We discuss the potential control technologies that may be used at Cement and Concrete Product Manufacturing facilities to meet the emissions limits in this final rule, including the potential for ammonia slip resulting from use of SCR or SNCR control technologies, in Section 3 of the Final Non-EGU Sectors TSD. The EPA is aware of the potential environmental impacts of ammonia slip but has concluded, for the reasons provided in Sections V and VI of the preamble, that NO_X emissions reductions from the Cement and Concrete Product Manufacturing industry are necessary to eliminate significant contribution to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS.

Comment:

Commenter (0513) points out while SNCR has been more widely adopted in the cement industry, it is infeasible and inappropriate for the EPA to apply a fleet-wide NO_X emissions limits of 1.95 lb/ ton clinker for preheater/ precalciner kilns based on installation of SNCR. According to the commenter, the available emissions reductions from SNCR are highly variable and depend on a number of unit-specific factors, including kiln type, design, raw material composition, and the type of cement produced. The commenter also states that kiln type and design impact the degree of difficulty encountered when installing SNCR injection systems on cement kilns, noting that the EPA has determined that SNCR was determined to be inappropriate for Portland cement plants in a BACT determination.

Response:

The final rule establishes a NO_X emissions limit of 2.8 lb/ton clinker for preheater/precalciner kilns. We provide the basis for the emissions limits applicable to cement kilns in Section 3 of the Final Non-EGU Sectors TSD.

Comment:

Commenter (0513) notes a review of the EPA's recent consent decrees involving cement facilities demonstrates that the EPA knows that the application of SNCR to cement facilities does produce uniform results, and the EPA has overwhelmingly declined to apply a uniform emissions limit, instead providing for a "test and set" approach by which individual kilns must demonstrate achievable emissions rates based on normal operating conditions with continuous operation of SNCR. Commenter (0516) noticed that the EPA incorrectly assumed none of the kilns screened for the proposed rule already operates SNCR, whereas three-quarters of the screened kilns have SNCR already installed. According to the commenter, those cement facilities would not be able to feasibly achieve the more stringent emissions standards required by the source cap limit and would not achieve the assumed 50 percent annual emissions reduction and prorated emissions reduction during the ozone season. The commenter adds that many cement kilns in the 23 affected states are already complying with a NO_X emissions limit developed through a consent decree, which largely impose reliance on SNCR systems, but the source cap limit of the proposed rule would impose a more stringent NO_X emissions limit than the consent decrees. The commenter states that the consent decrees were carefully negotiated between the EPA headquarters and regions, the U.S. Department of Justice, state governments, environmental and community groups, and industry to set achievable NO_X emissions limits and take into consideration varying kiln configurations and unique operating conditions.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0505) responds to the EPA’s request for comment on whether to retire long wet kilns and convert or replace with a more energy efficient kiln type and the time to accomplish. Instead of requiring retirement of long wet kilns, the EPA should evaluate if a long wet kiln could achieve the proposed emissions limits by installing additional NO_X controls to operate in conjunction with the SNCR. This approach is more cost-effective than requiring retirement. The EPA failed to examine whether controls are cost-effective for long wet kilns without justification.

Response:

As explained in Section VI.C.2 of the preamble, the final rule does not contain any requirement to replace or phase out existing long wet kilns.

Comment:

Commenter (0505) responds to the EPA’s request for comment on whether it is feasible or appropriate to require sources with existing preheater/precalciner kilns that use a variety of NO_X combustion control devices to add a post combustion such as SNCR or SCR to further reduce NO_X emissions to no more than 1.95 pounds of NO_X per ton clinker. The EPA incorrectly assumes that preheater/precalciner kilns are not already equipped with SNCR. In Texas, there are 11 preheater/precalciner kilns (out of 15 kilns total in Texas), and ten of the 11 are already equipped with SNCR control devices. Texas Industries, Incorporated, Midlothian Plant, RN100217199 is the only preheater/precalciner kiln in Texas not equipped with SNCR. However, as the EPA noted in its Proposed Non-EGU Sectors TSD the Texas Industries, Incorporated preheater/precalciner kiln routinely operates below 1.5 pounds of NO_X per ton of clinker. The EPA should revise its assessment of potential NO_X reductions and cost estimates by accurately accounting for existing operating efficiencies and control devices.

Response:

. The EPA reviewed title V permits for affected cement plants and has updated list of cement plants and NO_X control devicesincluded in our emissions reduction analyses. See Memorandum dated March 15, 2023, *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*. We respond in Section 2.2.5 (Comments that Facilities are Already Well-Controlled) to comments about existing controls on non-EGU sources. We respond in Section 2.2 (Non-EGU Industry Screening Methodology) to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluation of potential emissions reductions from these industries (including claims that the EPA has overstated the potential emissions reductions from non-EGU industries), and evaluation of related control costs.

Comment:

Commenter (0758) states while the EPA proposes to reduce NO_X emissions from cement kilns primarily through SNCR, it also admits that SCR "is now available in the cement manufacturing industry." In fact, SCR is in use at cement kilns across the globe, and in at least two cement kilns in the United States. One in Joppa, Illinois, has successfully demonstrated SCR use with a reported 80 percent removal rate for NO_X, and another in Midlothian, Texas, has been "running [SCR] smoothly since June 2017," reducing NO_X by greater than 70 percent. In May of this year, a mid/low-temperature SCR installation was completed on a cement kiln in Sichuan, China. As far back as 2008, the National Association of Clean Air Agencies recommended SCR as the best demonstrated technology for controlling NO_X from cement kilns, referred to SCR as "the regulated future" for cement kilns, and estimated that SCR could achieve NO_X rates of 0.5 lb/ton clinker. The EPA should require more stringent NO_X emissions limits on the basis of SCR technology.

Response:

As explained in Section 3 of the Final Non-EGU Sectors TSD, the EPA was aware of the use of SCR at a cement plan in Joppa, Illinois but SCR installations are not common at cement kilns in the U.S.

veryAs explained in Section V.D of the preamble, the EPA has identified an appropriate level of uniform NO_X control stringency for each non-EGU industry covered by the final rule that is cost-effective, widely available, and in use at many other similar non-EGU facilities throughout the country, and based on the air quality results presented in Section V of the preamble the EPA has concluded that the emissions control strategies identified and evaluated in Sections V.B and V.C of the preamble will deliver meaningful air quality benefits that collectively eliminate significant contribution to downwind nonattainment and maintenance receptors in the 2026 analytic year. For cement kilns, the emission limits in the final rule can be met through installation and operation of SNCR.

Comment:

Commenter (0758) adds for the installation of low-NO_X burners and post-combustion SNCR, the Ozone Transport Commission recommended modifying cement kilns to implement mid-kiln firing, which the EPA has estimated would take only 5-7 months to implement at a cost of only \$73/ton of NO_X reduction, and converting and retrofitting wet kilns to the more efficient and less polluting dry manufacturing process. According to industry sources (Bohan 2019) of the 128 kilns at the 91 U.S. cement plants, only 10 wet kilns remain in operation. Additionally, according to a 2021 analysis by the Sierra Club, long dry kilns can be converted to preheater/precalciner kilns, significantly reducing emissions. The EPA should set more stringent NO_X limits on the basis of converting and retrofitting wet kilns to modern technology.

Response:

Many cement plants in the U.S. have already installed post combustion NO_X control devices (e.g., SNCR), and the addition of low NO_X burners to existing kiln systems must be evaluated on a case-by-case basis. As explained in Section V.D of the preamble, the EPA has identified an appropriate level of uniform NO_X control stringency for each non-EGU industry covered by the final rule (including the Cement and Concrete Product Manufacturing industry) that is cost-effective, widely available, and in use at many other similar facilities throughout the country. Based on the air quality results presented in Section V of the preamble. the EPA has concluded that the emissions control strategies that the EPA identified and evaluated for cement kilns and other industries will deliver meaningful air quality benefits that collectively eliminate significant contribution to downwind nonattainment and maintenance receptors in the 2026 analytic year. Thus, as explained in Section VI.C.2 of the preamble, the final rule does not contain any requirement to replace or phase out existing long wet kilns.

Emissions Averaging

Comments:

Commenters (0324, 0516) believe the EPA should provide the same emissions averaging option for affected units at facilities in the other identified source categories. Any averaging options for any industrial source category should not result in less air quality benefits.

Response:

The EPA is finalizing provisions to allow owners and operators of engines in Pipeline Transportation of Natural Gas to seek EPA approval of facility-wide averaging plans but is not providing this compliance option to any other non-EGU industry. The EPA has concluded that unit-specific emissions limits on a 30-day rolling average basis for the cement industry are appropriate and consistent with other codified federal regulations for this sector.

Comment:

Commenter (0516) states if the EPA decides to maintain the 30-day rolling average period, The EPA must ensure it is consistent with existing NESHAP, NSPS, and PSD regulatory requirements to maintain ease of compliance. In the Portland Cement NESHAP, the 30-day rolling average is calculated by a new average value each operating day and includes the average of all valid hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit, based on pounds of pollutant per production unit (as is the case in the proposed rule), 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. If the EPA maintains the 30-day rolling average for complying with both the source cap limit and kiln-type limits, the EPA must be consistent with other regulations that cement manufacturing facilities must comply with. Those regulations include a 30-day rolling average that is to be calculated using Equation 6 of 40 CFR 60.64I(1) in the NSPS for cement kilns. This will avoid confusion and overly burdensome regulatory requirements.

Response:

Use of a 30-day rolling average period for the cement industry is consistent with other codified federal regulations for this sector.

Comment:

Commenter (0758) disagrees; instead, the EPA must require compliance on a 24-hr averaging period, as shown through Continuous Emissions Monitoring Systems. A 24-hr average will ensure that cement kilns do not idle emissions controls, such as SCR.

Response:

Use of a 30-day rolling average period for the cement industry is consistent with other codified federal regulations for this sector.

Outdated Data

Comments:

Commenters (0237, 0303) add the source cap formula is location-specific and cannot be applied at other locations. For the TCEQ 2007 cement rule, each of the three Texas plants had multiple kilns, including wet kilns, whereas none of the plants in CA have multiple kilns except Cemex Black Mountain (where there are two PH/PC kilns and no wet kilns). All cement kilns in CA are PH/PC kilns. The TCEQ formula was intended to provide flexibility to the three cement plants in Ellis County, based on the combination of wet kilns and PH/PC kilns that existed back in 2007. If the lb per ton clinker limit for PH/PC kilns that is embedded in the source cap limit is applied directly, the result is a lb per ton clinker limit that is closer to BACT than RACT and that may not be feasible in a retrofit application to existing kilns. Applying SNCR with stringent NO_X reduction levels in a retrofit application could result in high NH3 slip levels.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit. We note that it is not uncommon for the kilns that inject urea or ammonia for NO_X control to be subject to an ammonia limit of 10 ppm.[83]

[83] For example, see 30 TAC 117.3123(f).

Comments:

Commenters (0278, 0347, 0513, 0516) state the EPA seemed to have copied and pasted the source cap limit from the DFW Ozone NAAQS Nonattainment Area [25a] and deemed the formula sufficient for the proposed rule with little justification. The EPA seemed to reason since the source cap limit is being applied in DFW, the source cap limit could be applied more broadly for the cement industry to address "good neighbor" requirements. However, imposing the source cap limit from DFW more broadly to the industry presents several legal and technical issues that the EPA failed to evaluate or analyze. Had the EPA done sufficient due diligence, the EPA would have found that it is not feasible for the industry to comply with the proposed source cap limit. The source cap limit was developed after protracted negotiations between cement companies with kilns in the DFW, Midlothian, Texas, and the TCEQ to address the unique conditions in the DFW Ozone NAAQS nonattainment area, and therefore is not suitable for broader application. The source cap limit was developed specifically to address the unique cement plant configurations and raw material and fuel characteristics of the three companies operating in Midlothian, Texas, and to develop a NO_X emissions limit for the unique cement plant configurations that could address Ozone NAAQS nonattainment for DFW. Additionally, it should be noted, that there are no cement plants in the 23 affected states that operate both wet and dry kilns at the same location.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0336, 0359) question why the EPA is proposing semiannual testing for the cement and concrete product industry sector for a 5- month ozone season rule. The commenters restate the formula for the establishment of the daily allowable NO_X emissions cap in units of tons per day on a 30-operating day rolling average basis for each facility that includes cement kilns and briefly describes a portion of the calculation/formula, specifically defining the terms "ND" and "NW". The commenters state their belief that the implementation of the ozone season limitation, as described in the proposed rule is problematic because (1) often annual data for throughput at a kiln is not available until April or May of the following year at the earliest; thus, the EPA would not have the 2026 data available to recalculate this value prior to the start of the 2027 ozone season; and (2) there is no clear path to codify annual recalculations of the daily allowable NO_X emissions cap in the facility Title V permit; adding that facility and enforcement staff would need to confirm that calculations made by enforcement staff and facility personnel result in the same value annually prior to the ozone season to ensure that the applicable standard for each facility is well understood prior to the compliance period. The commenters recommend that the EPA modify the approach for calculating daily allowable NO_X emissions caps at each cement facility to accommodate the time needed to collect and report throughput data at the facility and the time needed by states to quality assure and submit that data to EIS. The commenters further ask that the EPA consider requiring the update of this daily value less frequently than annually. According to the commenters, a different limit taking effect each ozone season would make compliance significantly more difficult and present challenges to including such a numerical limit in a Title

V permit. The commenters suggest that the EPA consider aligning the recalculation of this limit with the Title V permit reissuance cycle or to recalculate this limitation every five or ten years unless a unit is retired from operation.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0347) argues RACT-based, source-specific requirements for cement kilns in one Texas County cannot and should not be adopted by mere reference and applied to cement plants in the 26 states that are the subject of the proposed FIP. With respect to wet cement kilns specifically, the EPA cannot justifiably rely on a wet kiln emissions factor for the equation used to calculate the "source cap limit" when it acknowledges that since 2015, none of the Texas cement plants that were evaluated in determining the Texas "source cap limit" "is using wet kilns [25b]."

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0516) continues, the EPA did not conduct an analysis to determine justifiable NO_X emissions factors for the source cap limit that could be applied to the industry more broadly. The emissions factors, KD and KW, used for the source cap calculation for the DFW nonattainment area, were determined based on actual emissions data from the sources located in Ellis County, which is included in the Dallas–Fort Worth–Arlington metropolitan statistical area, per a July 14, 2004, report prepared by ERG Inc. for TCEQ. The wet kiln NO_X emissions factor, 3.4 lb/ton clinker, is based on an approximate 35 percent reduction from Ash Grove’s actual average pound per ton of clinker emissions rate from 2003 to 2005. The 35 percent reduction assumes the operation of SNCR and is outlined in Tables 1-6 to 1-8 of the ERG report. The 1.7 pounds per ton of clinker emissions factor represents an approximate 45 – 50 percent reduction from Texas Industries Incorporated’s pound per ton of clinker emissions rate for 2001. The 50 percent reduction assumes the operation of SNCR and is outlined in Table 1-1 of the ERG report. The source cap limit has not been updated since it was finalized on June 14, 2007, and NO_X emissions limits for the cement kilns in Midlothian, Texas remain established based on production data between 2003-2005. The EPA did no such analysis of relevant NO_X emissions factors when adopting the source cap limit and did not set a specific time period for calculating the source cap limit. As a result of the EPA’s lack of due diligence, the source cap limit would impose limits for the broader industry that will not be feasible to comply with based on the most recent production data.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Unrealistic Emissions Cap

Comment:

Commenter (0278) states averaging the actual annual emissions over 365 days creates an unreasonably and unrealistically low daily emissions cap, as by definition, an annual average means many individual days have higher emissions. It would be more appropriate, since the emissions cap represents a daily emissions limit to be averaged over a 30-operating day rolling basis, to either (a) evaluate maximum monthly clinker production during the previous three-year period with the facility's historical operating days in that given month or (b) establish the potential clinker that can be produced in a given 30-day period.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comments:

Commenters (0347, 0516) state the short-term cap formula uses three years of annual clinker production data to generate an annualized production short-term production rate that is significantly lower than the actual peak 30-day production rates. This annualized rate includes normal production variability due to both annual and seasonal demand (including pandemic-related and other economic downturns), scheduled downtime for maintenance and turnarounds, and weather-based production slowdowns. Cement plants operate at their peak rates in the summer months (ozone season) when construction activity is highest and clinker demand is greatest. Wet and cold seasons also lower demand and therefore clinker production. This short-term variability is much greater than the one standard deviation (“SD”) included in the formula using annualized production data. Commenter (0516) believes maximum monthly short-term production rates will generally be 20-40 percent greater than a calculated 3-year annual average with an additional SD.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0347) adds there could be any number of reasons a cement plant experiences abnormally low production during a given year. A cement plant should not arbitrarily be required to curtail production for two or more years following a year in which there were abnormally low production volumes. While the proposed "source cap limit" equation would allow for the use of one standard deviation in calculating the past production variable (*i.e.*, the "ND" and/or "NW" values) [28], production data, especially abnormal data, may not follow a normal distribution and could be severely skewed. Therefore, should the EPA retain a cement-only "source cap limit," commenter (0347 believes it must not and should not. Instead, the EPA should grant affected facilities the ability to three years of annual production data over the course of the last five or even ten years and a standard deviation to determine the facility-wide "source cap limit."

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0278) argues historical actual production values should not be used to set potential emissions limitations. When setting permitted emissions limits, daily and annual emissions limits should be based on maximum facility operations, including maximum clinker production that a plant can manufacture. Using historical actual production values when determining the NO_X source cap limit in place of maximum design capacity (a) limits the industry's ability to respond to customer demand and (b) could lead to a restrictively low daily emissions caps for facilities who experienced a temporary decrease in production during the historical three-year period proposed to be used in determining the NO_X source cap limit. Imposing limits based on actual emissions is arbitrary and capricious and not authorized by section 110(a)(2)(D)(i) of the CAA, which requires consistency with other provisions of the CAA.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0510) believes the equation-based "source cap limit," on the other hand, may be problematic since it relies on two factors that take recent annual production into account. Of note, production has declined over the last two years given the slowdown in construction precipitated by the COVID-19 pandemic. If the source cap limit is to be calculated upon finalization of the rule, it could create an artificial constraint on a cement plants' ability to operate. Even if the source cap limit is to be calculated just prior to the 2026 operating season (and therefore consider more representative production years of 2023-2025), the EPA must ensure the limit, which originated as a local limit for a single Texas county's is rational as a regional control measure.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Stringency

Comment:

Commenter (0278) argues the pound NO_X per ton clinker emissions factor embedded in the source cap equation for preheater/precalciner kilns (*i.e.*, 1.7 pounds NO_X per ton clinker) is inconsistent with the 2.8 pounds NO_X per ton clinker emissions limit proposed for each individual preheater/precalciner kiln. As specified in the Technical Support Documentation for the proposed pounds NO_X per ton clinker emissions limit, the EPA evaluated current state-level standards and existing permit limits to determine that a 2.8 pounds NO_X per ton clinker is achievable in practice for the subject preheater/precalciner kilns. Applying a lower pound NO_X per ton clinker emissions limit through the source cap is contradictory and requires that existing kilns be able to meet a limitation which is closer to best available control technology (BACT) standards that are required of new kilns. It is worth noting that NSPS, subpart F (Standards of Performance for Portland Cement Plants) requires that new or modified cement kilns meet a 1.5 pounds NO_X per ton clinker limit, averaged on a 30-operating day rolling average. For sources with only preheater/precalciner kilns, the NO_X source cap limit renders the 2.8 pounds NO_X per ton clinker emissions limit illusory. The administrative record supports the 2.8 pounds NO_X per ton clinker emissions limit, not the 1.7 pounds NO_X per ton clinker emissions factor. It is arbitrary and capricious to rely on an emissions factor for the source cap equation that is not supported by the record and renders the emissions limit unusable.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0347) note the Cement and Concrete Production Manufacturing sector is the only non-EGU sector included in the proposed FIP with an additional daily “source cap limit.” The EPA proposes that an emissions factor of 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns and 3.4 pounds NO_X per ton of clinker for long wet kilns be used to calculate the “source cap limit.” In a footnote in the 180-page proposed FIP, the EPA states that the “source cap limit” equation and variables proposed to be included therein are based on the equation adopted as part of a Texas SIP revision to include reasonably available control technology ("RACT") requirements for cement kilns operating in the Dallas Forth Worth (D/FW) 1997 8-hr ozone nonattainment area. Therefore, unlike the proposed FIP's kiln-specific, production-based NO_X emissions limits, for which the EPA states are based on "available information for this industry, applicable state and local air agency rules, and active air permits or enforceable orders issued to affected cement plants," the proposed cement only "source cap limit" is based on a single equation in one state's SIP.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comments:

Commenters (0513, 0516) argue multiple factors affect the amount of NO_X emissions at cement manufacturing facilities that were not considered in setting NO_X emissions limits in the proposed rule, including burn ability from manufacturing different clinker types, fuel type, raw material variability, and age and design of the kiln system. In particular, for fuels, natural gas has relatively low nitrogen content --lower than coal or petroleum coke-- both of which are the traditional fuels used in cement manufacturing. But due to location and lack of pipeline access, many kilns do not have access to natural gas that can lower kiln NO_X emissions. In addition, the EPA recognizes that older kiln designs, including long wet and long dry, are less efficient than modern kilns and subcategorizes kilns for the kiln-type limits but the source cap limit would eliminate it as a factor when setting NO_X limits.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0516) states the EPA arbitrarily and capriciously proposed the source cap limit without evaluating the potential ability of the industry to comply with the requirement, and without following any standard regulatory procedures akin to Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/ LAER, and without presenting any justification for the source cap limit in the rule preamble, except for stating that the limit was to "provide operational flexibility." However, the proposed rule requiring the cement industry to comply with both the kiln-type and source cap limits does the exact opposite - would not provide any operational flexibility and potentially result in restricting production to meet the source cap limit. Therefore, the emissions cap formula is simply a mechanism to lower the effective emissions rate well below the listed rate limits in § 52.42(c)(1), Table NO_X Emission Limit Table.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0516) believes the EPA is arbitrarily co-opting the Texas Administrative Code ("TAC") source cap limit for the DFW Ozone NAAQS nonattainment area, and it would be improper to impose similar limits on areas that are in attainment for Ozone NAAQS because the EPA did not conduct a process under RACT/BACT/LAER to set a standard. For example, the kilns located in Pennsylvania in Berks, Butler, Lehigh, Northampton, and York Counties are all in areas of attainment for the 2015 Ozone NAAQS 8-hr standard, yet the proposed rule would impose nonattainment standards on those plants. There are also many plants located in areas of Missouri, Texas, Indiana, Ohio, Illinois, and other states that are in attainment and the proposed rule would impose nonattainment standards on those plants as well. Imposing a standard designed for nonattainment areas for the kilns located in attainment areas for the 2015 Ozone NAAQS would be improper.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit. With respect to the emissions limits that the EPA is finalizing for the Cement and Concrete Manufacturing industry, we provide in Sections V and VI.C.2 of the preamble and in Section 3 of the Final Non-EGU Sectors TSD our rationale for establishing these emissions limits as part of a set of control requirements in upwind states that, taken together, will eliminate “significant contribution” to downwind nonattainment and maintenance receptors for the 2015 ozone NAAQS.

Comment:

Commenter’s (0516) analysis using 2019-2021 annual clinker production data, regardless of kiln type, estimated that the daily source cap limits during the ozone season, could be more stringent than the 1.5 lb/ton clinker standard for new kilns under the NSPS. It is worth noting, the NSPS for cement kilns at 40 CFR 60 subpart F outlines the method for determining the standard of 1.5 lb/ton clinker for new kilns. The EPA reasoned that there were numerous examples of kilns without SNCR that could feasibly meet an emissions standard of 3.0 lb/ton clinker and with the application of SNCR with expected emissions reduction of 50 percent, the standard was set at 1.5 lb/ton clinker. During the development of the NSPS for cement kilns, the EPA considered setting the limit lower than 1.5 lb/ton clinker but believed that the data from new kilns, regardless of location and fuel and raw material inputs, showed that new kilns could not meet a standard lower than 1.5 lb/ton clinker. Based on technology limitations, it is infeasible for an existing kiln to comply with an emissions standard that is more stringent than a newly constructed, state-of-the-art kiln. Furthermore, there are instances where long dry kilns must meet NO_X emissions limits more stringent than preheater/precalciner kilns, which is not feasible based on technology limitations. Commenter (0516) states in its apparent rush to issue the proposed rule, the EPA did not seem to analyze the source cap limit and whether it would be feasible to comply with. After gathering annual clinker production data from 2019 to 2021 from PCA members and calculating the potential source cap limit for the affected existing cement manufacturing facilities, preheater/precalciner, precalciner, and long wet kilns would be subject to a NO_X emissions limit that would be infeasible to meet. The source cap limit also did not identify preheater, long dry, and semi-dry kilns in the formula, leaving commenter (0516) to estimate the potential limits for those kilns or assume no source cap limit applies to these kilns.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0758) disagrees, stating the NO_X limit for cement kilns should be strengthened, therefore the source cap limit should be strengthened as well.

Response:

We provide the rationale for the final rule’s emissions limits for cement kilns in Sections VI.C.2 of the preamble and Section 3 of the Final Non-EGU Sectors TSD. As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

<u>Clarifications and Corrections</u>

Comments:

Commenters (0237, 0303) believe there is no clear connection between the source cap limit for cement plants (which is based on ton/day limits) and the NO_X reduction calculation in the TSD (which is based on 50 percent NO_X reduction for all included plants). Hence, the cement NO_X limits in the rule language and the emissions reduction calculation in the TSD are not consistent with each other. Commenters (0237, 0303) argue California cement companies have already been subjected to RACT (and BARCT) in the past five years (since the 2015 ozone standard was issued), and hence should be exempted from the FIP.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit. To the extent the commenter intended to argue that sources subject to RACT requirements should be exempted from good neighbor requirements under CAA section 110(a)(2)(D)(i)(I), we disagree as the CAA does not provide for any such exemption.

Comment:

Commenter (0347) offers this additional comment on the air pollution control and cost data that the EPA has apparently relied on in issuing the proposed FIP. The information the EPA relied on for its Screening Assessment for non-EGU sources, and in particular, the cement industry information, is incorrect. The EPA lists both kilns that are operated by Armstrong Cement in its dataset. In the "existing control" column, the EPA lists "none specified" for both of Armstrong Cement's kilns. As already noted, however, both of Armstrong Cement's kilns are equipped with SNCR units for NO_X emissions control. This incorrect datapoint may be one of many examples of incorrect or outdated data and information relied on by the EPA.

Response:

The EPA reviewed the respective title V permit for the cement plant kilns of concern during comment period and has updated the control device type (SNCR) for both of these kilns on the kiln list. We also are making this update of information available in docket.

Comment:

Commenter (0513) states the source cap equation does not account for all kiln types, making obligations under the source cap unclear for covered facilities. Commenter strongly suggests that, at a minimum, the EPA should consider establishing subcategories and setting requirements tailored to each subcategory. The programs this rule is modeled after –NSPS and NESHAP—include this flexibility for good reason address– to address variation within source categories. Cement facilities utilize a wide variety of kilns, beyond the categories listed by the EPA in this rule. In calculating the source cap limit for individual cement plants, the EPA defines 2 emissions factors, “KD” and “KW”, which apply to dry preheater-precalciner/ precalciner kilns and long wet kilns, respectively. However, certain kilns are considered semi-wet. The EPA’s good neighbor FIP does not indicate whether all kiln types are included in the proposed source cap, and, if they are, which emissions factor will apply to other kiln types. This problem is made worse by the EPA’s failure to define the kiln types that it does list in the proposed FIP. For example, the EPA lists preheater-precalciner kilns and preheater kilns separately but does not define the differences between these classifications. Given the significant differences between these types of facilities, it is imperative the EPA reexamine and clarify the basis for and applicability of the source cap equation.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0516) notes the emissions rates that were negotiated for the DFW nonattainment SIP for a very small and specific group of kilns. The emissions cap factor of 1.7 lb NO_X/ton clinker for dry preheater-precalciner or precalciner kilns is 39 percent and 26 percent lower than the limits the EPA deemed appropriate in Table VII.C-2: Summary of Proposed NO_X Emissions Limits for Kiln Types in Cement and Concrete Product Manufacturing. The emissions cap factor of 3.4 lb NO_X/ton clinker for long wet kilns is 15 percent lower than the limit the EPA listed in the rate table. Commenter (0516) continues, the short-term cap begins with a production rate 20-40 percent lower than actual ozone season production rates and uses an emissions factor 15-40 percent lower than determined in the EPA's analysis. Multiplying these two artificially low values together to get the emissions cap leads to an effective emissions rate limit using the emissions cap that is 35-80 percent lower than the emissions rate table the EPA prepared as part of this rule. This effectively negates the emissions rate table and puts in place a 1.0 to 1.5 lb NO_X /ton clinker limit, more stringent than the BACT standard for new kilns, that will not be achievable by existing well-controlled kilns without curtailing production.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

5.3.2.3 Monitoring, Recordkeeping, and Reporting

CEMS

Comments:

Commenters (0347, 0513, 0516) state many in the industry are already continuously monitoring NO_X emissions. Commenter (0347) is required by its Title V Operating Permit (Permit No. 10-00028) to operate a NO_X CEMS. NO_X stack testing is unnecessary for sources that are continuously monitoring NO_X emissions using a CEMS. Therefore, while commenter (0347) does not provide any comment on whether it is feasible or reasonable to use NO_X CEMS or CPMS on all cement kilns, it does use and has successfully used NO_X CEMS at its facility. The EPA should revise the proposed FIP to exempt sources employing NO_X CEMS from the unqualified proposed semi-annual NO_X stack testing requirement. Without additional details about the proposed monitoring of NO_X emissions requirements, commenter (0516) cannot provide meaningful comments on the vague requirements. However, commenter (0516) would like to note that it would not be appropriate for the EPA to require semiannual testing where CEMS is in operation, as those kilns should be able to comply with a NO_X monitoring requirement through continuous NO_X monitoring. These types of details are critical for the industry to understand how to comply with the proposed rule.

Response:

The 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 (CPMS) 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 may be conducted during the corresponding calendar year[84] and 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.

Comment:

Commenter (0336) attached a permit dated February 2, 2015, for Roanoke Cement Company, EIS facility identification number 5039811. This permit contains requirements for a number of CEMS including SO_2 and NO_X. This is provided in response to the EPA requesting comment on equipping cement kilns with continuous emissions monitoring systems (CEMS).

Response:

We appreciate commenter providing information in support its position. The 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

[84] 40 CFR 63.11237 "Calendar year" defined as the period between January 1 and December 31, inclusive, for a given year.

to demonstrate continuous compliance with the NOx emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance tests may be conducted during the corresponding calendar year and 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.

Comment:

Commenter (0513) encourages the EPA to permit cement facilities to monitor emissions using CEMS in lieu of semiannual performance testing. Based on its experience, commenter (0513) believes that monitoring NO_X emissions by requiring CEMS at covered cement facilities is an efficient and effective means of ensuring compliance with measures in the proposed FIP. The real-time direct measurements provided by CEMS allow facilities to control operations and reagents to minimize costs. The accuracy of these measurements is regularly evaluated based on the EPA's extensive quality assurance procedures for performance specifications.

Response:

We appreciate commenter's sharing its experience concerning use of CEMS in lieu of semiannual performance tests. As explained elsewhere in this document, the 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 may be conducted during the corresponding calendar year and 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.

Comment:

The majority of covered cement kilns already operate with CEMS and overwhelmingly utilize CEMS to monitor NO_X emissions. A review of recent permit actions using the EPA's RBLC Clearinghouse Database similarly confirms that most cement kilns already have CEMS installed and operational—16 recent permits for cement and product manufacturing facilities have provided for NO_X compliance monitoring using CEMS. As explained by one report, "[c]ement companies have many years' experience with these types of systems. For example, the main cement manufacturing companies in the UK have, over the last two decades, tested and evaluated various types of analysis equipment. Consequently, most companies have [standardized] their equipment manufacturer/supplier and type." The widespread adoption of CEMS and industry experience with CEMS monitoring weigh strongly in favor of requiring CEMS instead of semiannual performance testing.

Response:

We appreciate commenter's statement concerning widespread adoption of CEMS at the main cement manufacturing companies in the UK. As explained elsewhere in this document, the 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 may be conducted during the corresponding calendar year and 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.

Comment:

Commenters (0336, 0359) explain in the proposal under 40 CFR part 52.42(c)(2), the EPA sets a daily allowable NO_X emissions cap in units of tons per day on a 30-operating day rolling average basis for each facility that includes cement kilns. A portion of the calculation associated with this formula are for the variables "ND" and "NW," which are defined as follows:

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

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0336, 0359) state that such a facility-wide daily limit would be calculated and begin applying in the ozone season of 2026 and thereafter. Implementation of this ozone season limitation as described in the proposed rule is problematic for a number of reasons. Data availability is an issue. Often annual data for throughput at a kiln is not available until April or May of the following year at the earliest. For example, 2026 data for throughput would be due to a state in the April or May 2027 timeframe and submitted to EIS in the October 2027 timeframe. Under a FIP, the EPA would not have the 2026 data available to recalculate this value prior to the start of the 2027 ozone season. The EPA's proposal appears to require that the daily allowable NO_X emissions cap be recalculated annually.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0336, 0359) question how would this federal requirement be codified in the facility's Title V permit? A state could reference the formula without calculating the value that is applicable to each unit, but that approach is much less straightforward for compliance purposes since inspectors must then calculate the value every year outside of the permit. Facilities and inspector staff would need to ensure that calculations made by compliance staff and facility personnel result in the same value each year and prior to the ozone season to ensure that the applicable standard for each facility is well understood before the compliance period.

Response:

The commenter appears to be concerned with how to implement the proposed source cap limit in title V permits. As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0336, 0359) recommend that the EPA modify the approach for calculating daily allowable NO_X emissions caps at each cement facility to accommodate the time needed to collect and report throughput data at the facility and the time needed by states to quality assure and submit that data to EIS. Commenters (0336, 0359) also recommend that the EPA consider requiring the update of this daily value less frequently than annually. A different limit taking effect each ozone season would make compliance significantly more difficult and present challenges to including such a numerical limit in a Title V permit. The EPA could consider aligning the recalculation of this limit with the Title V permit reissuance cycle. Another approach would be to recalculate this limitation every five or ten years, unless a unit is retired from operation.

Response:

As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenters (0347, 0513, 0516) agree semiannual performance testing is impractical and unduly burdensome. The EPA's performance testing methods are complex and highly technical, requiring significant time and sources to comply [87]. Requiring performance testing on a semiannual basis would interfere with operations at cement plants.

Response:

As explained elsewhere in this document, the 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 may be conducted during the corresponding calendar year and 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.

Comment:

Commenters (0347, 0516) respond to the EPA's request for comment on whether it is feasible or appropriate to require affected kilns to be equipped with CEMS or CPMS in lieu of performing semiannual stack tests. Commenter (0516) states the EPA is proposing to require cement facilities to comply with 30-day source cap limits through semiannual performance testing for a 5-month compliance period, which is an obvious mismatch of compliance monitoring to compliance periods. The proposed rule does not provide details on how to demonstrate compliance with the 30-day rolling average through performance tests and how to report compliance with these limits. Kilns should be given the option to comply with a periodic stack testing requirement. For those kilns opting to conduct periodic stack testing, such testing should only be required during the ozone season. Since the ozone season is five months, testing should only be required once a year during the ozone season.

Response:

Given widespread use of SNCR as the preferred post combustion NO_X control of choice for cement kilns across the nation and the common use of CEMS associated with that method of control, we anticipate the majority of cement plants will opt to use CEMS for compliance purposes, but the final rule also allows facility owners/operators to use annual performance tests and parametric monitoring to demonstrate compliance. As a result, the EPA has established provisions in the final rule allowing affected units in this industry that operate NO_x 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 NO_x 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 NO_x emissions limits. To avoid challenges in scheduling and availability of testing firms, the annual performance tests may be conducted during the corresponding calendar year and 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. As explained in Section VI.C.2 of the preamble, the EPA is not finalizing the proposed source cap limit.

Comment:

Commenter (0513) strongly opposes requiring CPMS to monitor NO_X emissions levels at cement facilities. The EPA is "soliciting comment on whether it is appropriate for the affected units (kilns) to use CPMS instead of CEMS to monitor the NO_X concentration (emissions level)." CPMS generally relies on parameters such as temperature, pressure, or flow rate monitoring. Cement kilns typically operate under conditions that are unsuitable for these measurements— "The inside of a cement kiln is an extremely challenging environment for making any kind of measurement. Temperatures are high, there is a lot of dust and tumbling clinker can damage in situ measuring instruments." These challenges are exacerbated by the high variability of the operating conditions, because "the conditions within a kiln are not homogeneous and there is a complex relationship between the reactions, mass transfer, heat transfer, and mechanical dynamics of the processed material."

Response:

Given the widespread use of SNCR as the preferred post combustion NO_X control of choice for cement kilns across the nation and the use of CEMS associated with that method of control, we anticipate the majority of cement plants will opt to use CEMS for compliance monitoring purposes, but the final rule also allows facility owners/operators to use annual performance tests and parametric monitoring to demonstrate compliance.

Comment:

Commenter (0513) concludes CPMS is not widely available in the cement industry and has not been widely adopted. Therefore, the EPA should not require CPMS for compliance monitoring.

Response:

The 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.

5.3.3 Iron and Steel Mills and Ferroalloy Manufacturing

Comment:

The commenter (0798) adds that the resulting proposed rule imposes limits on NO_X emissions that the EPA's own analysis acknowledges have never been demonstrated in the iron and steel industry and cannot be met by any technology currently available for use in the iron and steel industry. According to the commenter, many of the technologies proposed by the EPA to control NO_X (*e.g.*, SCR, SNCR) are not technically feasible for the emissions units included under the proposed rule. The commenter notes that even if technology used in wholly dissimilar industrial processes were able to be implemented, the costs would be significantly higher than the thresholds the EPA relied upon for screening out available control technologies. The commenter further states that the EPA also assumes that low NO_X burners are an available technology for certain emissions units to reduce NO_X emissions, completely ignoring the fact that many of these units already incorporate low NO_X burner technology. The commenter adds that associated production downtimes to add controls also would have severe economic consequences for the industry. Furthermore, the commenter contends that efforts to adapt these technologies to the iron and steel industry would increase emissions of other pollutants and require re-engineering and modifications to not only the steel making process, but also existing air pollution control equipment. The commenter relates that the addition of ancillary equipment to address flue gas characteristics and the batch nature of the steelmaking process would drive up costs and have both upstream and downstream impacts that would not have been accounted for in the original equipment design specifications. Further, the commenter remarks that the proposed rule also makes assumptions regarding equipment availability and constructability that cannot be reconciled with present and future supply chain considerations and threatens to hamstring the economy and national security with extended downtime or closures and resultant shortages of domestic iron and steel supply.

Response:

The EPA acknowledges the scarcity of facilities operating SCR, SNCR, and similar low-NO_X technologies in the iron, steel, and ferroalloy industries. Of those facilities operating low-NO_X burners, we have found that each burner is operated with different target specifications, including different expected NO_X reduction efficiencies as compared to similar emissions units, and that little data is available to evaluate the potential for transferring such technology to other units with comparable stoichiometry in this sector.

We disagree, however, with the commenter's assertion that "...many of the technologies proposed by the EPA to control NO_X (e.g., SCR, SNCR) are not technically feasible for the emissions units included under the proposed rule," as this claim is overly broad and incorrectly assumes that the absence of a clear demonstration that these technologies have been implemented at specific types of emissions units necessarily establishes that the technologies are not technically feasible for those emissions units.

Commenter also contends that engineering efforts to integrate these technologies at certain iron, steel, and ferroalloy emissions units would be cost-prohibitive. The EPA is aware of many examples of past successful efforts to integrate add-on pollution control technology in the iron, steel, and ferroalloy industries. In some cases, the implementation of new technology was required by settlement agreement (following an EPA or state enforcement action) or by rule. Supply chain considerations, though relevant to the identification and fabrication of certain control technologies fitted to individual facilities, do not necessarily give rise to economic hardship, nor do shortages of equipment and construction materials "[create] shortages of domestic iron and steel supply."

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 anticipates that with adequate time, modeling, and optimization efforts, NO_X reduction technology may be achievable and cost-effective for these emissions units in the Iron and Steel Mills and Ferroalloy Manufacturing sector. However, 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. As such, the EPA is finalizing requirements only for reheat furnaces and certain industrial boilers, as described more fully in Section VI.C of the preamble to the final rule and Section 4 of the Final Non-EGU Sectors TSD. To the extent a particular reheat furnace or industrial boiler is unable to comply with the requirements of the final rule due to technical impossibility or extreme economic hardship, the final rule includes provisions allowing the owner or operator to apply for a case-by-case alternative emissions limit. *See* Section VI.C of the preamble and 40 CFR. 52.40(d).

Comment:

Commenter (0798) express concerns that labor and local economies will likely be negatively impacted by both, temporary and/or permanent closure of facilities. The commenter says that, in the case of steel workers, workers often find other occupations (other steel mills to work at) or remain indefinitely unemployed. The commenter also notes that extended time away from work may result in some staff to lose specialized skills needed for performance, which is especially challenging considering recruitment is "typically not easy". According to the commenter, the US steel producers already experience higher production costs than those in other areas of the world (due to environmental/regulatory obligations).

Response:

As discussed in Section VI.C.3 of the preamble, the EPA is only finalizing requirements for reheat furnaces rather than the 11 unit types as proposed. The commenter has not raised any specific concerns with our framework for establishing emissions limits for reheat furnaces. The EPA does not expect prolonged shutdowns or high costs to install low-nox burners on the reheat furnaces subject to this final rule.

Comment:

Commenter (0416) requests that the EPA remove the iron and steel industry from the rule or start over from the beginning of the rulemaking process to gather more input from the industry.

Response:

The EPA requested comment on all aspects of the proposed rule, including non-EGU industrial sources included in the proposed rulemaking. The EPA responds to comments received about the inclusion of the iron and steel sources in the proposed rule in this chapter of the RTC document. The EPA does not agree that the rulemaking process needs to be "restarted" to gather sufficient input from industry to complete the rulemaking.

5.3.3.1 Comments that the FIP should not apply or set requirements on blast furnaces, basic oxygen furnaces, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or electric arc furnaces.

Comment:

Commenter (0504) notes given the significant differences between the integrated iron and steelmaking process and the EAF steel production process, it is not surprising that the EPA and states have long recognized these distinctions in regulations promulgated under the CAA. Indeed, as early as 1973, when the EPA first proposed to identify integrated iron and steel plants as among the categories of stationary sources that cause or significantly contribute to "air pollution which may reasonably be anticipated to endanger public health and welfare," it based this finding and the resulting NSPS ("NSPS") only on emissions from BOFs. In the ensuing decades and through multiple NSPS reviews, the EPA has continued to delineate the iron and steel source category based on utilization of BOFs.

Commenter (0280) believes the proposed rule fails to recognize existing NO_X emissions reduction strategies already implemented by EAF operators. The commenter notes that underestimating current NO_X controls significantly decreases the amount of additional reduction that is achievable and the cost of incremental reductions beyond what is already achieved in practice is much greater. According to the commenter, the EPA acknowledges that uncontrolled NO_X emissions from EAFs range from 0.5 to 0.6 lb/ton for EAFs equipped with oxy-fuel burners. The commenter states that while the EPA also cites a lower ppm value from an EAF without oxy-fuel burners, there are only two samples and no process information is provided making it impossible to determine what weight, if any, should be given. In any event, the commenter asserts that modern EAF practice relies upon burners to supplement the electric arc and minimize cold spots in the furnace. Therefore, the commenter determines that no significant consideration can be given to the "without concurrent burner" data, at least as it relates to steel production.The commenter notes the EPA's preamble and Proposed Non-EGU Sectors TSD suggest that vacuum degassers, often known as vacuum tank degassers or VTDs, are susceptible to control by low-NO_X burners and SCR. Due to the operation and nature of a vacuum degasser, controlling NO_X emissions using a scenario of low-NO_X burners and an SCR is not practicable. The EPA defines a "Vacuum Degasser" as "a unit operated within an iron and steel facility to expose molten steel at low pressure to remove certain gases during steel refinement." This definition is correct; however, the EPA's Proposed Non-EGU Sectors TSD then states: For vacuum degassers utilized in secondary steelmaking, the EPA based the limit of 0.03 lb/mmBtu on existing permit limits of 0.05 lb/mmBtu. The EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X technology, including use of SCR. The commenter states it is not clear what "low-NO_X" technology the EPA is referring to in its discussion. At least as used by commenter (0280), a VTD is a ladle which is placed either within a cylinder or with a close-fitting cap and the atmosphere is removed either mechanically or by steam ejection from a boiler. No burners or other combustion occurs. Because there is no combustion, low-NO_X burners are not an option. The dominant off-gases from a VTD are carbon mono$_x$ide, hydrogen, oxygen and nitrogen with some particulate. NO_X is not typically a significant component. For example, at the Nucor Steel Tuscaloosa mill in Alabama, the BACT limit is 0.005 lb/ton. Assuming a million tons of steel were produced, this represents a total NO_X contribution of 2.5 tons/year. Any add on control technology, much less SCR or SNCR, is not cost-effective when applied to such a small source. Additionally, many VTDs are evacuated to flares (for CO control). Introduction of an SCR unit is problematic because any ammonia slip would be subsequently re-oxidized to NO_X, likely increasing overall NO_X emissions. Accordingly, commenter (0280) does not find that vacuum degassers can be technically and economically controlled in the fashion presented in the proposed rule. The commenter argues ladle preheaters are also not susceptible to easy ductwork control. The ladle needs to be able to be picked up and moved by crane or similar conveyance. This precludes delicate control or tight- fitting connections. There is no effective way to recover the exhaust from the ladle preheater. Because the ladle preheater is open to the environment, substantial infiltration air would be accrued with any effort to collect emissions. The resulting inlet temperatures would be too low and too diffuse for effective SCR control. SNCR, which requires a considerably higher temperature, is wholly out of the picture. The commenter continues, for ladle and tundish preheaters, the EPA proposed emissions limit for ladle preheaters are based on the emissions limit found in an existing permit limit at 0.1 lb/mmBtu, citing a 2021 BACT determination established in a Nucor Steel Kankakee permit. The EPA then inappropriately applied a further 40 percent reduction by SCR. Commenter (0280) agrees that the majority of recently issued permits limit NO_X emissions from ladle and tundish preheaters to 0.1 lb/mmBtu. In the Proposed Non-EGU Sectors TSD, the EPA states "EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X technology, including potential use of low-NO_X burners and selective catalytic reduction." The Proposed Non-EGU Sectors TSD provides no further discussion of how the proposed 0.06 lb/mmBtu limit is achieved. The commenter continues, the existing "lowest achievable emissions rate" (LAER) and "best available control technology" (BACT) determinations in the RBLC do not support the EPA's contention that emissions limits below 0.1 lb/mmBtu are achievable. There is no reference to a ladle preheater achieving less than 0.098 lb/mmBtu, which is functionally equivalent to 0.1 lb/mmBtu, but derived by taking the standard 100 lbs/mmscf NO_X emissions factor for natural gas burners and dividing by 1020 Btu/scf rather than 1000.

Commenter (0758) states for vacuum degassers, the EPA proposes a NO_X limit of 0.03 lb/mmBtu. However, permit limits support a more stringent limit. Thus, more stringent limits are likely achievable for vacuum degassers.

Commenter (0359) states the screening assessment does not include any ladle/tundish preheaters. The justification for the proposed NO_X emissions standard of 0.06 lb/MMBtu for ladle/tundish preheaters, which is almost twice as stringent as the 2021 BACT permit limit identified, assumes a 40 percent reduction with the installation of SCR.

Commenter (0504) begins, to derive the proposed 0.05 lb/mmBtu NO_X limit for ladle and tundish preheaters the preamble to the proposed FIP "assume[d] 40 percent reduction [from baseline emissions limits established in permits] by SCR." The Proposed Non-EGU Sectors TSD, on the other hand, presumed that 40 percent NO_X reductions were only achievable though the application of LNB technology and SCR for ladle and tundish preheaters and vacuum degassers. Here again, the EPA's preamble and Proposed Non-EGU Sectors TSD are in perfect agreement as to the precise percentage of NO_X emissions that can be feasibly reduced but are completely inconsistent in their identification of the controls that the EPA presumes will achieve those reductions.

Commenter (0758) states for ladle/tundish preheaters, the EPA proposes a NO_X limit of 0.06 lb/mmBtu. This limit is within the range of BACT/LAER permit limits.

Commenter (0798) states gas burners on the preheaters are very small with heat inputs of typically 5-15 MMBtu/hr. In addition, the preheaters are needed to be mobile so that they can be use don ladles throughout the shop. The very small heating value, coupled with the de minimis NO_X emissions from ladle preheating, and the inconsistent and mobile operation makes SCR technologically infeasible. And even if SCR were technologically feasible, which it is not, it would not be economically feasible, as even if the emissions from the units were able to be captured in a hood and treated, the cost estimate of nearly \$50,000/ton of NO_X removed, not including any costs associated with hooding and other infrastructure needed to accommodate the technology. Simply, the proposed limit based upon application of SCR is perplexing.

Commenter (0359) states there is only one blast furnace identified in the screening assessment with a control cost of over \$10,000 per ozone season ton. The justification for the proposed NO_X emissions standard of 0.03 lb/MMBtu for blast furnaces assumes a 40-50 percent reduction from a burner replacement plus SCR is based on one NO_X RACT rule limit.

Commenter (0798) states the blast furnace converts iron oxide into molten iron for subsequent refining in the BOPF shop to produce steel. A typical burden (feed) may consist of iron ore, pellets, sinter, limestone, coke, mill scale, BOPF slag, and other iron bearing materials. The burden material is charged into the top of the furnace and slowly descends through the furnace. The coke provides the thermal energy required for the process and provides carbon to reduce the iron oxide and to remove oxygen in the form of CO. To U. S. Steel's knowledge, SCRs are not installed on any blast furnaces domestically or internationally, and in the TSD and docket materials, the EPA does not cite to any successful application of SCR at any blast furnace (BF). This is because SCRs are not technologically feasible as a NO_X control for blast furnaces; nor are they cost-effective. Commenter (0798) conducted a BART analysis of the blast furnace at Gary Works in 2020 and a RACT analysis at the Edgar Thompson facility in 2014 both of those evaluations indicated the proposed rule is not feasible.

Commenter (0798) continues, BFs use blast furnace gas (BFG), coke oven gas, or other heat sources to generate the heat necessary to metal the iron. The use of regenerative heat capitalized on the blast furnace gas. Blast furnace gas is a low NO_X gas and already uses a best practices approach and minimizes the impact on air emissions. Any excess BFG is flared to minimize air impacts. The EPA seems to fail to realize that the SCR technology is not compatible with a BFG gas flare. If BFG was not used to heat the BF then it would require increased use of natural gas, which would have a negative impact on air emissions.

Commenter (0798) continues, the application of the proposed rule to BFs and the limits established were incorrectly achieved. As stated by Trinity Consultants: "For blast furnaces, EPA started with an Ohio RACT limitation and then assumed a 50 percent reduction (from that RACT limitation) based on application of a control technology never before applied to this source type. The EPA uses similar approaches for the proposed emissions limits for all steel units in proposing emissions limits far below those determined as either BACT or RACT in unit-specific analyses. The EPA appears to base its approach on an incorrect interpretation of the data in MCM and CoST and does not include any fact-based finding that these technologies are applicable to the steel emissions units as part of this proposal."

Commenter (0758) states the proposed limit of blast furnaces is consistent with recent permit limits [307]. However, this proposed limit is higher than the average uncontrolled emissions from blast furnaces of 0.021 lb/mmBtu, reported in 1994 (with an uncontrolled minimum of 0.002 lb/mmBtu) [308]. And the EPA estimates that reductions from control technologies such as low-NO_X burners and flue gas recirculation (FGR) can achieve pollution reductions of 55 percent to 77 percent [309]. Thus, the EPA's proposed limit for blast furnaces is likely achievable, and should be strengthened.

Commenter (0798) states basic oxygen process is treated differently than all other non-EGU sources. In the other various non-EGU sources there is PTE of 100 tpy of NO_X as individual emissions units to be included in the proposed rule. However, BOP operations are required to combine all emissions units in determining whether the emissions limits in the Proposed rule apply to the emissions units at the BOP operations. This combining of emissions units results in the application of SCR requirements to potentially very small emissions units that do not have an associated stack. Requiring SCR emissions controls on units that emit very few tons of NO_X per year is overly burdensome, costly and will have no impact on downwind states. The result is illogical.

Commenter (0798) continues, the BOP is not conducive to the application of the proposed rule's SCR technology to decrease NO_X emissions. BOPs typically operate with a wet scrubber exhaust system which produces a gas too cool to go into a SCR/SNCR without significant conditioning and heating. Even assuming there is sufficient space, the BOP exhaust system would have to be a completely new design likely to include larger fans and increased duct work. The gas would also have to be heated to temperatures compatible with the SCR resulting in significant, independent NO_X emissions. Both of these equipment additions would lead to increased natural gas and electricity usage.

Commenter (0798) believes the EPA did not consider the costs for redesign of the BOP systems (nor should it as such redesign goes beyond RACT), modification of equipment and process to attempt to work with the SCR requirement, additional equipment needed, additional natural gas, or additional electricity costs. In the EPA's limited understanding of the iron and steel process they also failed to realize that imposing the SCR technology will also lead to emissions increases associated with the increased usage of natural gas and electricity. Nothing in the rulemaking docket indicates that the EPA considered these costs and impacts; and how the (incorrectly) assumed reductions benefit downwind states.

Commenter (0798) continues, it is significant to note that the EPA has not shown how SCR has been applied on any BOP Shop; and that the anticipated reductions are indeed achievable – technologically and economically. In the TSD, the EPA states that it based the emissions limit of 0.07 lb/ton of steel on performance testing data from BOFs without NO_X reduction controls at integrated iron and steel mills in the United States. The EPA then projected what it refers to as a minimal 50 percent NO_X reduction efficiency that the EPA, without any support whatsoever, is achievable by use of low- NO_X technology, including potential use of FGR and selective catalytic reduction." EPA's rather simplistic approach is that because most BOF vessels and associated BOF Shops in the United States are already equipped with capture technology and existing PM control devices, the NO_X reduction technology could simply be integrated to the existing controls. This over-simplification is not supported by fact or law. The EPA has not shown that SCR has been successfully applied to BOP Shops. The dynamic conditions in the exhaust gases, including dramatic swings in flow and temperature (*e.g.,* oxygen blow vs. charging or tapping) make SCR inappropriate – and this is supported by the fact that the EPA and states/air agencies have never applied SCR to the BOF process shops for any RACT, BACT or LAER determination. However, with the broad stroke in one simple paragraph, the EPA, without any support, upends decades of prior determinations, and now inexplicably claims SCR is somehow feasible and appropriate. The TSD is scant on any support – but instead the EPA relies on false assumptions.

Commenter (0758) states for BOFs, the EPA estimates that uncontrolled BOFs emitted 0.12 lb/ton on average in 1994 (with an uncontrolled minimum of 0.042 lb/ton), and that "minimally" 50 percent NO_X reduction is achievable through use of pollution controls. Thus, the EPA's proposed limit for BOFs is likely achievable.

Commenter (0298) argues the EPA fails to identify a single ferroalloy EAF that has achieved an emissions limit anywhere near the proposed rate for EAFs in the proposed rule. In the Proposed Non-EGU Sectors TSD, the EPA cites to several iron and steel mill source categories to identify possible NO_X controls but not a single ferroalloy or steel melting EAF source. For example, the EPA looks to an annealing furnace (Proposed Non-EGU Sectors TSD at 30-31), which the EPA subsequently asserts "has been shown to be capable of achieving up to a 90 percent reduction of NO_X emissions" with the "combination of LNBs and SCR." Id. at 32. Ferroalloy EAFs are wholly distinct from annealing furnaces (ferroalloy EAFs do not use combustion burners as part of their processes); thus, the EPA's reference to NO_X reductions achieved at annealing furnaces has no relevance as to the feasibility of such controls and reductions at a ferroalloy EAF. The other sources the EPA looks to in the Proposed Non-EGU Sectors TSD are related to the iron and steel mill categories (*i.e.,* reheat furnaces, BOF, coke plants and blast furnaces). Thus, any NO_X emissions limits achieved at such furnaces are irrelevant to what may be achievable at ferroalloy EAFs. In fact, the EPA's own Alternative Control Techniques Document for NO_X emissions from Iron and Steel Mills, which the EPA cites to in the Proposed Non-EGU Sectors TSD, affirms that NO_X control technologies like SCR and SNCR have not been demonstrated feasible at EAFs. See Alternative Control Techniques Document – NO_X Emissions from Iron and Steel Mills, EPA-453/R-94-065 (Sept. 1994), at 5.3.5 (acknowledging that "[t]here is no information that NO_X emissions controls have been installed on EAF's or that suitable controls are available"). It is worth noting, both the Proposed Non-EGU Sectors TSD and the Alternative Control Techniques Document instead cite to a Japan Iron and Steel Federation's report of the installation of SCR units on sintering plants, coke ovens, and reheating furnaces. However, SCR was found to be impractical for sintering plants (for a variety of technical reasons including low temperature, high dust loading, and space limitations), and SCR applications in Japan for coke ovens and reheating furnaces appear to be experimental. The lack of successful SCR operation in Japan was confirmed in a BACT Analysis submitted by Republic Steel to the Indiana Department of Environmental Protection.

Commenter (0298) states in Table VII.C-3 of the proposed rule, the EPA cites to "[e]xample permit limits at around 0.2 lb/ton" and "[a]ssumes 25 percent reduction by SCR to achieve 0.15 lb/ton steel" to justify a 0.15 lb/ton NO_X emissions limit on EAFs. 66 Fed. Reg. at 20145. This emissions limit is not achievable because there is no technically feasible NO_X control that can be implemented at ferroalloy EAFs to achieve such reductions.

Commenter (0298) believes NO_X add-on control technologies like SCR and SNCR are not "known controls" for the ferroalloy manufacturing industry. The EPA relied upon "known controls" for the non-EGU units covered by the proposed rule. By the EPA's own definition, neither SCR, SNCR, nor any other add-on NO_X controls, are "known controls" for ferroalloy EAFs. Absent add-on NO_X controls, the proposed NO_X emissions limit for EAFs are simply not achievable. Commenter (0298) conducted a review of the RBLC. Seventy-one (71) facilities involving at least 60 EAFs were identified that had been permitted between January 2000 and May 2022. Only 1 entry involved a ferroalloy facility; all others involved combustion units at steel mills. Results of this assessment confirmed that add-on NO_X controls have not been installed on a silicon metal, ferroalloy furnace, or submerged electric-arc technology furnace in the United States. And for steel manufacturing EAFs, only combustion controls (*e.g.,* LNBs, oxy-fuel burners, ladle heater burners, etc.) and direct evacuation control systems were identified for add-on NO_X controls; these are inapplicable to ferroalloy EAFs. For example, a recently issued permit to a steel melting facility, V&M, identified the use of direct evacuation control, monitoring, LNBs and proper oxy-fuel burner operations as BACT for NO_X to achieve a limit of 0.40 lb NO_X/ton steel; and the use of low NO_X/oxy-fuel burners at a steel melter mini mill, Bluewater, to achieve a 0.35 lb NO_X/ton steel. No steel EAFs were identified with SCR or SNCR for NO_X control. The EPA cannot impose NO_X emissions limits on ferroalloy EAFs that are theoretically only achievable by controls that are not "known" for the ferroalloy facility. The EPA's proposed regulation of ferroalloy EAFs is, therefore, arbitrary and capricious. While the EPA's proposed NO_X emissions limit for EAFs is unachievable for the ferroalloy industry, commenter (0298) also objects to the proposed averaging time for the emissions limit. The EPA appears to propose a "3-hr rolling average" for the emissions limit under proposed Section 52.43(c) (66 Fed. Reg. 20181). By contrast, in the preamble EPA appears to propose a “30-operating day rolling average period.”. To the extent the EPA is proposing a 3- hour rolling average for EAFs to achieve the 0.15 lb/ton NO_X emissions limit, commenter (0298) notes that a 3-hr rolling average would make complying with the 0.15 lb/ton limit (assuming achieving that level of control was feasible, which it is not) extremely challenging, if not impossible, for ferroalloy EAFs because of the inherent fluctuation and variability in the formation of NO_X through thermal NO_X generation. Commenter (0298) asserts that the EPA has no data to substantiate regulation of the ferroalloy industry under the proposed rule. The EPA cannot propose a NO_X emissions limit of 0.15 lb/ton or require installation of NO_X add-on controls because such controls have not been achieved in practice at an EAF. However, if the EPA seeks to regulate ferroalloy EAFs, at most the EPA could consider requiring compliance with work practice standards to minimize the generation of NO_X emissions at EAFs. The EPA proposed this approach for Taconite Production Kilns. The EPA proposed work practice standards in lieu of NO_X emissions limits because it “does not currently have the data to determine appropriate emissions limits that these units could achieve by installing low NO_X burners.” See 66 Fed. Reg. 20146. Commenter (0298) continues, the EPA lacks the data to determine appropriate NO_X emissions limits for ferroalloy EAFs. The EPA reached the same conclusion in the Sinova PSD permit, identifying “best practices and design and operation” of the EAFs.

Commenter (0798) believes the EPA is including taconite kilns in the proposed rule because they are part of “iron and steel mills and ferroalloy manufacturing,” this is incorrect. Taconite production is not part of iron and steel or ferroalloy manufacturing. The modeling underlying the proposed rule categorizes emissions units based on the NAICS Code of the subject facilities. The NAICS code for iron and steel manufacturing is 3311. Metal ore mining, including taconite production, has NAICS code 2122. This is documented in the EPA’s own modeling data from September 29, 2021. It is arbitrary to include taconite kilns in the proposed rule because the EPA has not modeled the significance of their contribution to any downwind receptor as would be required.

Commenter (0798) states for Taconite Kilns, the EPA proposes that low-NO_X burners will result in a reduction of 40 percent of NO_X emissions. There is nothing in the record to support this conclusion. It is the EPA’s obligation to “examine the relevant data and articulate a satisfactory explanation for its action including a ‘rational connection between the facts found and the choice made.’” State Farm, 463 U.S. at 43; see also 42 U.S.C. § 7607(d)(3) (the statement of basis and purpose must include “the factual data on which the proposed rule is based,” “the methodology used in obtaining the data and in analyzing the data,” and “the major legal interpretations and policy considerations underlying the proposed rule”). Nonetheless, U. S. Steel has, in the time allowed, identified several inaccuracies and improper assumptions in the feasibility and effectiveness of pollution control equipment for the iron and steel industries, and has documented those findings in the attached reports within commenter’s (0798) attachment.

Commenter (0798) continues, taconite production is not separately mentioned in the Non-EGU Screening Assessment which is the EPA's sole basis for determining which industries had a significant enough impact relative to subject to the proposed rule. The EPA states that that modeling was done on the basis of NAICS code, which would mean that taconite kilns were not included in the modeling of the contributions from the Iron Steel and Ferroalloy industry since taconite production belongs to a different NAICS code. This is confirmed by the fact that there appear to be no taconite kilns listed in the list of facilities and emissions units evaluated as part of the Non-EGU Screening Assessment. Because taconite production was never modeled to be a significant contributor to downwind nonattainment or maintenance issues, it cannot be regulated under the good neighbor provision of the CAA. Furthermore, there is no rational basis to treat Taconite as part of the Iron and Steel and Ferroalloy Manufacturing Industry Group. Taconite production is not co-located with iron and steel manufacturing. As a result, there are no taconite production kilns "at an iron and steel mill or ferroalloy manufacturing facility." Taconite production does not use similar processes, have similar emissions profiles, or use similar pollution controls. There is no factual basis to conclude that taconite production and iron and steel manufacturing have similar impacts on down- wind receptors, similar costs of pollution controls, or should otherwise be grouped together for purposes of screening or regulation under the proposed rule.

Commenter (0798) states NO_X emissions from taconite kilns are already regulated by detailed regional haze FIPs covering Minnesota and Michigan. Minnesota has noted in prior comments that the Taconite FIP is already responsible for just under 11,000 tpy in NO_X reductions in the state, including 5,700 tpy from U. S. Steel's Keetac and Minntac facilities. This is a demonstration of the considerable environmental improvements that have already been achieved in Minnesota air quality and interstate transport of NO_X from Minnesota. The proposed rule recognizes the effectiveness of the Taconite FIP, pointing to the FIP requirements as the very requirements needed by the Taconite industry "to achieve the required emissions reductions [to satisfy the] remaining interstate transport obligations for the 2015 ozone NAAQS." Even if the Taconite Industry were subject to regulation under the EPA's Screening Assessment, this finding would support excluding the Taconite Industry from further regulation, because there are no further restrictions needed to prevent significant contribution to nonattainment or interference in maintenance of the ozone NAAQS, and the EPA is not permitted to over-control sources.

Commenter (0798) states Minnesota has itself urged the EPA to "have these significant reductions included in the 2016v2 inventory for non-EGUs" rather than take credit for them in the new FIP. But the EPA does not draw the right conclusion from the results of the Taconite FIP. No other non-EGU is subject to this type of double-regulation in the proposed rule, and the EPA provides no justification for singling out taconite kilns in the proposed rule. As with other industries that are not Tier 1 sources and do not have large boilers subject to Tier 2, the Taconite Industry should be excluded from the proposed rule.

Commenters (0280, 0798) express applying SCR at an LMF is inappropriate and illogical. In addition, the application of SCR is not technically feasible, in part due to the batch process of the LMF. Even if one were able to determine how to implement the SCR on an LMF, it would not be cost-effective as it would require an entire redesign of the system and process with de minimis reductions in NO_X. Furthermore, because the EPA includes LMF as part of the BOP Shop, there is no de minimis threshold for the applicability of the FIP to LMFs (assuming that the BOP Shop's PTE (from all units within the shop) is 100 tons or more. This is illogical – so illogical that the cost effectiveness would be approach $2 million per ton of NO_X removed – several orders of magnitude of EPA's purported cost threshold of $7,500/ton. Furthermore, the EPA has not shown how LMFs (individually or aggregately with other emissions units) interfere with ozone attainment in downwind states; nor has the EPA shown how the emissions limits for LMFs would lead to any measurable benefits in ozone in downwind states. Commenter (0280) adds due to heavy particulate loading, catalyst plugging and poisoning, and low temperatures, SCR is not an effective technology for LMFs. Similarly, SNCR is not a technically feasible technology because the sustained temperature profile necessary for its operation does not occur. Instead, LMFs are deeply cyclical and often out of the operating temperature range for SNCR. This renders SNCR technically impracticable to control NO_X emissions from LMFs.

Commenter (0758) disagrees that for ladle metallurgy furnaces, the EPA's proposed limit of 0.1 lb/ton is likely achievable because other permit limits indicate a more stringent limit.

Commenter (0280) continues, the EPA states that SCR should achieve a minimum of 25 percent reduction when applied to EAFs. No basis is provided for this statement. In short, the record is absent of any actual technical information relating to the application of SCR technology to an EAF or an example of an SCR controlling emissions from an EAF. Technically, SCR technologies are poorly suited to control NO_X emissions from an EAF. SCR requires a catalyst, which is subject to fouling. By the EPA's own calculation, the particulate emissions rate of an EAF is between 38 and 50 pounds of particulates per ton of steel prior to particulate controls. This PM emissions rate is approximately five times higher than what is typically emitted from a coal-fired boiler. At that particulate loading, the EPA estimated annual catalyst replacement if the SCR is placed prior to the particulate controls. This configuration of placing the SCR prior to the baghouse is clearly technically infeasible. If forced to install a SCR prior to the baghouse, a catalyst life of 2-3 months, or even annually, would be cost-prohibitive.

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Commenter (0280) adds while the EPA does not propose selective non-catalytic reduction (SNCR), it is similarly infeasible. It requires higher temperatures than SCR but is also subject to nozzle fouling. SNCR also requires steady state conditions, but gas generation and temperature are highly variable and cyclical in the EAF environment, rendering SNCR technically impracticable].

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Commenter (0280) notes in Table VII.C-3-Summary of Proposed NO_X Emissions Limits for Iron and Steel and Ferroalloy Emissions Units, the EPA states that the proposed NO_X emissions standard for "Electric Arc Furnaces" of 0.15 lb/ton steel is based on "Example permit limits at around 0.2 lb/ton. The EPA then erroneously assumes an additional 25 percent reduction by SCR to achieve 0.15 lb/ton steel."

Commenter (0280) continues, although the RBLC lists two Timken mills in Ohio as subject to a NO_X limit of 0.2 lb/ton, the compliance status is listed as unverified. The current Timken Faircrest Title V operating permit converts this 0.2 lb/ton to 10.833 tons/month on a 12- month rolling average. However, Timken Faircrest is not required to conduct a performance test to verify this limit. According to the 2016 Title V permit, the last performance test occurred in 2006, and the results of that test are still used to validate compliance to the present time. Based on the discussion in the Timken Faircrest permit, it appears both permits were issued based on the same demonstration. Commenter (0280) does not find that a single limit, unverified for over 16 years and apparently based on a one-time stack test, provides an adequate basis for establishing the NO_X emissions limits that will universally apply to multiple, unique facilities. Commenter (0280) concludes based on the review of the RACT/BACT/LAER Clearinghouse, an appropriate NO_X emissions limit for EAFs should not be more stringent than 0.30 to 0.42 lb/ton, which is routinely achievable by combustion controls or measures other than SCR.

Commenter (0280) believes it is not practicable, nor appropriate, for the EPA to require substantial reengineering of co-controlled pollutant systems after they have been properly permitted and constructed unless it takes into consideration all of the extensive retrofitting issues involved, which the EPA has manifestly not done in this rulemaking or the technical record. The proposed rule contradicts multiple "best available control technology" decisions finding such co-controlled systems are the best and most effective way to control emissions from EAFs and LMFs. Further, the proposed rule does not consider the substantial space constraints in existing shop operations. As proposed, the EPA is requiring a wholly separate air pollution control scenario, which adds considerably costs and increases greenhouse gas emissions and other air pollutions. The proposed rule does not include a cost analysis of the additional controls specifically required for the Iron and Steel Mills and Ferroalloy Manufacturing industry. And the proposed rule does not account for the additional emissions related to SCR applicability, primarily ammonia, sulfuric acid mist, and PM.

Commenter (0359) states the screening assessment does not include any electric arc furnaces (EAF). The justification for the proposed NO_X emissions standard of 0.15 lb/ton of steel for electric arc furnaces is based on an example permit limits at around 0.2 lb/ton and assumes 25 percent reduction from the installation of SCR to achieve 0.15 lb/ton of steel. It is more than twice as stringent as the 2022 BACT emissions limit (0.35 lb/ton of steel) for a newly permitted facility in West Virginia. Commenters (359, 504) provide three factors contributing to SCR not being an appropriate choice for use on an EAF.

1. EAFs operate primarily using a batch process (rather than a continuous process). Emissions are generated during a cycle of charging, melting, and tapping. When being charged, the furnace roof is open and emissions are not directly evacuated to the exhaust stack. Therefore, the emissions (and the characteristics of the exhaust stream) captured and evacuated to the primary control device (EAF Baghouse) through the direct shell evacuation control system, the system used on most new EAFs pursuant to 40 CFR part 60, subpart AAa, are intermittent and change during this operational cycle. An SCR is not a preferred control technology in these types of applications where the pollutant load concentration, exhaust temperature, and flow rates change regularly with a batch type process.

2. The emissions during charging or other times the furnace roof is open are controlled through the use of a canopy hood that also evacuates to the EAF Baghouses. This hood collects air from not just from the open EAF but also from other emissions sources within the melt shop building. This canopy hood then also evacuates to the EAF Baghouses. This exhaust stream will also, based on the nature of the operations within the Melt Shop at the time, have a varying pollutant load concentration, exhaust temperature, and flow rates which is unsuitable for an SCR.

3. The primary pollutant of concern (see 40 CFR 60, subpart AAa and 40 CFR 63, subpart YYYYY) from an EAF is PM, and the use of the EAF Baghouses require the temperature of the exhaust stream to be around 300°F. An SCR would have to be located downstream of this baghouse to properly control NO_X and prevent damage from particulate fouling. Therefore, use of an SCR would require the exhaust stream to be reheated after passing through the baghouse. Heating a high-volume exhaust stream like one from an EAF to proper temperature for SCR control would result in collateral emissions of NO_X from the additional fuel that would have to be combusted to provide the heat.

Commenters (0359, 0504) add related to point (2) above, based on the intermittent usage characteristics of the smaller heaters within the melt shop (ladle/tundish preheaters) and the fact that the emissions of these units are vented within the melt shop itself, any use of an SCR would have to be based on collection of NO_X emissions from the canopy hood, which is not practical. This is similar to the annealing furnaces located outside the melt shop. These smaller units, often multiple sources less than 10 mmBtu, also vent individually within a building, precluding the practical use of SCR.

Commenters (0359, 0504, 0557) note there were no examples of SCR being used on EAFs in the RBLC in the previous five years of BACT determinations. There is no evidence that the EPA provided any objection while reviewing these BACT determinations based on SCR being appropriate as BACT. Based on the above, it is hard to conclude that the EPA conducted a detailed engineering analysis for the proposed controls in this industry sector. Proposing add-on controls to BACT emissions limit is purely political and is not remotely based on a scientific approach.

Commenter (0504) states based on limited testing available prior to 1994, that NO_X emissions ranged from 12 – 98 ppm. In fact, the data shown by the EPA from the 1994 ACT shows a range of 80 – 110 ppm for EAFs with oxy-fuel firing. Since almost all EAFs in the current industry use oxyfuel firing, it is useful to compare the 80- 110 ppm noted by the EPA with current data. Average hourly NO_X levels, in current EAFs are far smaller than 80 - 110 ppm. In fact they are generally less than 10 ppm, and often lower. And even the hourly maximums are less than 50 ppm. CEMS data confirm that such maximums last only a few minutes in a typical heat.

Commenter (0504) believes these differences are significant for pollution control purposes. First, the EPA's base assumption about the NO_X levels from the 1994 ACT are simply not reflected in NO_X measurements from current EAFs. And, importantly, actual hourly NO_X levels are so low – *i.e.*, 10 ppm or less – with occasional short-duration spikes that may be a few tens of ppm – that it has significant adverse ramifications for add-on NO_X controls such as SCR. In fact, even the 1994 ACT confirms that no add-on NO_X controls are feasible for EAFs: "There is no information that NO_X emissions controls have been installed on EAFs or that suitable controls are available." Even the hourly average data are mostly below 10 ppm with a few spikes occasionally. The minute-by-minute data are even more variable, with spikes lasting for very short durations. The key point is that, even with oxy-fuel firing, NO_X concentrations from current EAFs in the gases exhausting the EAF are very low.

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Commenter (0504) explains while there are a few applications of so-called "tail-end SCRs," in other industries, where the SCR catalyst is installed at the end of the exhaust gas control train, the temperatures at such a location at an EAF mill (*i.e.*, after the baghouse in the case of EAF meltshops with EAFs and LMSs) are so low (around 200F or lower) that the entire volume of exhaust gases, typically close to a million standard cubic feet per minute or more in most EAF mills, would need to be reheated to the minimum temperatures for the tail-end SCR to be effective (which can be around 300 to 350 F). The additional fuel use (and NO_X generation) alone would make this simply impractical and clearly cost-ineffective, at any reasonable cost-effectiveness cut-off, much less at $7,500 per ton of NO_X reduced. Of course, there would be substantial additional adverse environmental impacts from installing and operating SCR, including increases in $PM_{2.5}$, CO, and VOC emissions. GHG emissions would also increase due to the added fuel use necessary to reheat the exhaust gases to the proper SCR temperature.

Commenter (0758) adds for electric arc furnaces (EAFs), the EPA proposes a NO_X limit of 0.15 lb/ton of steel produced. Emission limits set to achieve BACT/LAER, including with use of only low NO_X burners or no pollution controls, indicate that the EPA's proposed limits for EAFs are likely achievable with pollution control technologies. The EPA should also consider oxy-fueled firing, which industry has found is feasible and is already in use at EAFs. In other industries, the EPA estimates that oxy-fueled firing can achieve NO_X emissions reductions of 85 percent.

Commenters (0280, 0359, 0504, 0798) note the EPA proposes to establish limits for annealing furnaces, which it defines as "a furnace used to heat materials at very high temperatures to change their hardness and strength properties." The EPA proposes a limit of 0.06 lb/mmBtu. The Proposed Non-EGU Sectors TSD states this: For annealing furnaces, the EPA based the emissions limit of 0.06 lb/mmBtu on projected reduction efficiency of 40-50 percent based on current permit emissions limits and operating rates compared to natural gas usage. The EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X technology, including potential use of newer generation low-NO_X burners or optimization of existing burners, or combination of low-NO_X burners, flue gas recirculation, and/or SCR.

Commenter (0280) states these bell annealing furnaces also have limited firing capacity. Almost all the Nucor bell annealing furnaces are rated at or under 6 mmBtu/hour. The oldest bell annealing furnaces emit approximately 0.4 lb of NO_X per mmBtu, resulting in the total PTE for NO_X emissions calculated to be 8.76 tons of NO_X per year. Most bell annealing furnaces in Nucor's fleet emit at a rate of 0.1 lb NO_X per mmBtu, or about 2.26 tons/year. Because of their portable nature, emissions cannot be aggregated. Add-on controls are cost ineffective at these emissions rates. For these reasons, the EPA should exclude all portable bell annealing furnaces from applicability under this rule.

Commenter (0359) states the screening assessment does not include any annealing furnaces. The justification for the proposed NO_X emissions standard of 0.06 lb/mmBtu, which is 33 percent less than the lowest emissions limit that the EPA identified, is based on an assumption of 40 percent reduction from the single lowest limit due to the installation of SCR.

Commenter (0504) continues, as with EAFs, LMSs, and reheat furnaces, the Proposed Non-EGU Sectors TSD cites to limits in the 1994 NO_X ACT in support of its NO_X reduction presumptions. In Section 5.3.8 of the 1994 NO_X ACT, the EPA correctly notes that "...annealing and galvanizing are accomplished at moderate temperatures usually below 540 C (1,000 F) . . . Because of these much lower temperatures, NO_X emissions from these processes should be lower..." meaning that they should be lower than NO_X emissions levels from reheat furnaces where process temperatures are higher than 1,000 F. Recall that the EPA had noted that uncontrolled NO_X levels in regenerative reheat furnaces (which are expected to have higher NO_X emissions due to the use of hot combustion air, for thermal efficiency reasons) were 560 ppm at 3 percent oxygen. Yet, in Section 5.3.8.1 of the 1994 NO_X ACT, the EPA comes up with an uncontrolled NO_X level for annealing furnaces of 1,000 ppm, which is greater than the uncontrolled NO_X level for a reheat furnace.

Commenter (0504) continues, in that section, the EPA cites to Table 4-4 in the 1994 NO_X ACT and admits that "[T]here are no uncontrolled emissions data available...Uncontrolled NO_X emissions from two annealing furnaces are reported to be 1,000 ppm at 3 percent O2..." Examination of this table shows that the 1,000 ppm was the upper-most range of NO_X reported for annealing furnaces, with no citation details as to how this was developed or from where the EPA obtained this uncontrolled value. This is important because the rest of the EPA's Section 5.3.8.1 discussion uses the 1,000 ppm uncontrolled NO_X level to deduce control efficiencies for various schemes, such as 97 percent reduction via LNB+SCR and even assuming that 85 percent control efficiency CE should be possible. It then proceeds to simply use these high levels of CE forgetting about the 1,000 ppm uncontrolled NO_X level assumed in deriving these efficiencies to begin with. The fact is that uncontrolled NO_X levels from annealing and galvanizing furnaces should not be greater than uncontrolled NO_X levels from reheat furnaces. And, like reheat furnaces, current annealing furnaces, in most cases, already use LNB. So, baseline NO_X emissions are nowhere near 1,000 ppm. In fact, they are lower than 0.2 lb/MMBtu. As a result, the EPA's presumed control efficiencies, resulting NO_X reduction levels, and cost-effectiveness determinations for these smaller furnaces, are not properly supported and are, in fact, fundamentally flawed.

Commenter (0504) notes that annealing (and tempering) furnaces can be of various sizes and are design as specialty furnaces to accomplish the annealing (or tempering) actions specific to particular products and batch sizes. As one example, for "bell annealing" furnaces, a crane is required to physically list the furnace and place it over the "bell" containing the coils to be treated. This crane-operated lifting process renders commonly used "bell annealing" furnaces incompatible with add-on emissions controls. Thus, one-size fits all solutions are not feasible. And, in many instances, such furnaces may be located within larger shops with no stacks making add-on controls even more problematic because any additional pressure drop in the exhaust will alter the pressure profile of the furnace. Commenter (0504) sees no indication in the record that the EPA considered any of these aspects either in its technical analysis and/or its cost analysis for these furnaces.

Commenter (0758) states for annealing furnaces, the EPA proposes a NO_X limit of 0.06 lb/mmBtu. This limit is consistent with permit limits, through use of ultra-low NO_X burners and flue gas recirculation or SCRs. Additionally, annealing furnaces are often subject to limits around 0.075-0.080 using low or ultra-low NO_X burners alone. Thus, the EPA's proposed limit of 0.06 lb/mmBtu for annealing furnaces is likely achievable through low or ultra-low NO_X burners and additional pollution controls.

Commenters (0280, 0359, 0416, 0504) argue that the EPA has not provided a justification for including this source category in the proposed rule, nor has it provided adequate justification for the proposed emissions standards. According to the commenters, the lack of proven technologies and data to establish proposed emissions limits for this source category is especially troubling, considering that the EPA proposed emissions standards for 15 separate emissions units and assumed control reduction efficiencies. The commenters state that the EPA must re-propose this rule for the iron and steel and ferroalloy section with an analysis demonstrating that its proposal is attainable.

Commenter (0416) states that the EPA's approach to setting the proposed NO_X limit for blast furnaces is technically suspect and largely lacking in explanation. According to the commenter, the EPA states in the TSD that the proposed NO_X emissions limit is based on "potential use of low-NO_X burners, flue gas recirculation, and SCR," but there is no support for, or an explanation of, its determination that NO_X controls are feasible for a blast furnace, let alone specifically low-NO_X burners, flue gas recirculation, and SCR. Commenter (0416) continues that the TSD references some uncontrolled NO_X emissions rates from blast furnaces, but the EPA instead appears to rely solely on the Ohio SIP rule establishing a case-by-case NO_X RACT limit for one blast furnace of 0.06 lb/MMBtu. The commenter goes on, saying that there is no discussion on the suitability of this single uncontrolled emissions limit to other blast furnaces and there is a lack of engineering assessment as to the feasibility that control efficiencies never implemented as proposed are attainable in practice. The commenter remarks that the EPA identified an extremely wide-ranging reduction efficiency of 20 percent on the low end and 90 percent on the high end and seemed to arbitrarily settle on a 50 percent CET develop the final emissions limit, without any explanation of its basis.

Commenter (0504) notes the control strategies that the EPA identified as mere "proxies" in Step 3 of the Agency's multi-step analysis became the control strategies it assumed would apply "across all units of the same type" in Step 4 of the Agency's analysis. According to the commenter, to estimate the precise emissions limits the Agency deemed achievable through the Step 3 control strategies, however, "EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees." Commenter (0504) reviewed this same information as well as substantial additional information available in the administrative record for the proposed FIP or readily available to the Agency. The commenter states that this record plainly reveals that the emissions limits the EPA proposed to impose on emissions units at EAF steel producers are entirely baseless.

Commenter (0300) remarks that the EPA modeled emissions of NO_X from five out of the 91 facilities in the Iron and Steel Mills and Ferroalloy Manufacturing sector. The commenter noted that three of those modeled are older steel mills that use blast furnaces and BOFs known to produce high levels of NO_X, one facility is a coke battery with boilers combusting coke oven gas, and one of facility uses an EAF. According to the commenter, the Proposed Non-EGU Sectors TSD focuses almost exclusively on blast furnace and BOF design and control considerations, yet the EPA's proposed rule appears to include all facilities in this sector with 100 tpy of facility wide NO_X emissions.

Commenter (0300) argues that the Proposed Non-EGU Sectors TSD does not provide any example of where SCR has been used in this industry sector in the U.S. and can only speak to such use on the large melting furnaces in overseas applications, which may or may not have been successfully deployed or still in use today. However, the commenter notes that the EPA has assumed SCR technology can be applied to the main melting furnaces, the ladle preheaters, the reheat furnaces, the annealing furnaces, the vacuum degassers, the ladle metallurgy furnace, and the coke ovens.

Commenter (0300) states that in a steel mini-mill, most sources do not operate in a steady-state manner. For example, the commenter notes that the EAF is a batch process; the ladle preheaters and vacuum degassers operate for a fraction of a given hour; and the annealing furnaces may operate at varying and reduced rates based on the metallurgical properties required. According to the commenter, some of the furnaces and heaters are not equipped with adequate stacks to support add-on controls, and stack gas would have to be reheated to route it through an SCR. The commenter states that the EPA has not performed an adequate technical evaluation of this industry sector to determine if SCR is technically feasible as assumed. The commenter adds, that as steel companies appear to be primed to replace older plants with steel "mini-mills," which emit approximately one-tenth the greenhouse gases of traditional steel mills and result in reductions to generally all other regulated pollutants on a per ton of steel produced basis, imposing emissions standards that are unachievable in practice could not only slow down this progress but result in continued reliance on steel imports from facilities with much larger environmental footprints in countries not inclined to minimize air emissions to the extent that the U.S. is committed.

Commenter (0416) argues that the proposed rule relies on assumptions and generic conclusions, and the detrimental aspect of this approach is compounded by the fact that the proposed rule does not include any flexibility to take into consideration site-specific variables. Commenter (0416) provides an example of the fundamental differences between the manufacture of carbon steels and stainless steels at EAF shops. According to the commenter, the differences in EAF (a batch process) operation result in a wide range of NOX emissions rates between these product classes. Specifically, the commenter states that in the manufacture of certain stainless steels, there are considerably longer heats and lower concentrations of NOX in the exhaust gas streams than for carbon steels. The commenter asserts that this difference alone can radically change the fundamental technical and economic feasibility of certain NOX control strategies. In another example, commenter (0416) provides that not all BOF shops are built the same, and the cost for adding NOX controls (if feasible) can vary greatly depending on items such a physical space for control equipment, surrounding infrastructure in the shop, and other engineering factors. Due to this substantial site-by-site variability, the commenter asserts that to the extent that iron and steel emissions units remain subject in the final rule, the final rule should adopt a case-by-case compliance option. The commenter claims that the use of case-by-case assessments in rulemaking is a standard approach to ensure the rule fairly identifies site-specific circumstances.

Commenter (0504) states that while the preamble to the proposed FIP and the Proposed Non-EGU TSD both agree on the NO_X limit achievable for EAFs (0.015 lb/t), they claim that the EPA derived that proposed limit in two completely and irreconcilable ways. According to the commenter, each document asserts that the EPA used a different baseline (0.2 lb/ton v. a range of 0.20 – 0.35 lb/ton), each assumes a different emissions reduction efficiency (25 percent v. 40 percent), and each identifies different NO_X controls as capable of achieving these emissions reductions (SCR v. LNB + SCR). The commenter adds that the Proposed Non-EGU Sectors TSD purports to base its NO_X emissions baseline on emissions data and permit limits from mini mills, integrated iron and steel facilities, and ferroalloy facilities, but the commenter points out that only mini mills use EAFs. The commenter argues that the EPA could not have arrived at the precise same proposed emissions limit using these two wholly distinct and irreconcilable assumptions and suggests that the EPA's analysis started with the emissions limit the Agency wished to impose first and then manipulated the assumptions and data sources necessary to reach its predetermined emissions limit. The commenter continues that to derive the proposed NO_X limit for LMSs, the TSD projected that minimally 40 percent NO_X reduction efficiency is achievable by use of low- NO_X technology, including potential use of low-NO_X burners and SCR, while the preamble to the proposed FIP assumed 40 percent reduction by SCR alone. The commenter adds that nowhere in the administrative record does the EPA explain how it determined that companies could reduce NO_X emissions from EAFs and LMSs using SCR or how these emissions reduction efficiencies could be achieved. The commenter opines that the EPA's technical feasibility analysis relies solely on information from its 1994 ACT document, which the commenter claims is largely irrelevant today and much of it is simply wrong. The commenter points out that the EPA subsequently supported the Indiana Department of Environmental Management's determination that SCR was technologically infeasible for EAFs. Commenter (0504) adds that nothing in the 1994 ACT aligns with the justifications the EPA used in the preamble to the proposed FIP and in the Proposed Non-EGU Sectors TSD, and in fact, multiple aspects of the 1994 ACT directly contradict the EPA's (albeit inconsistent) conclusions about technological feasibility of using SCR for controlling NO_X from EAFs or LMSs.

Commenter (0798) continues, the proposed rule contains many internal inconsistencies regarding the extent of reductions assumed by the EPA in performing modeling and setting proposed emissions limits. For example, just with respect to EAFs, the rule proposed rule states that it "[a]ssumes 25% reduction by SCR," whereas the Proposed Non-EGU Sectors TSD states that it projects "efficiency of 40-50% as compared to existing permit limits for EAFs" and "minimally 40% NO_X reduction efficiency is achievable by use of low-NO_X technology, including potential use of low-NO_X burners and selective catalytic reduction." And the Non-EGU Screening Assessment estimated no reductions from EAFs. To draft a non-arbitrary rule, the EPA must make a consistent assumption about the emissions reductions associated with the proposed rule, and actually use that same assumption when modeling costs, feasibility, and air quality impacts at downwind receptors.

Commenter (0280) states that the EPA's EAF limit is not achievable. The commenter notes that the limit is 0.2 lb of NO_X per ton with an additional 25 percent reduction by applying SCR. According to the commenter, ever if the limit were generally achievable, it would not be achievable on a 3-hr basis. The commenter states that SCR units must be brought up to temperature before the urea or ammonia can be introduced, and it is likely that this process could take up to an hour, given the large mass of catalyst required for an emissions system potentially moving 1 or more actual cubic feet per minute (CFM). The commenter calculates that the following result:

$E = (0.2 \text{ first hour} + 0.15 + 0.15)/3 = 0.17 \text{ lb/ton}.$

Commenter (0280) states that, in effect, the EPA seeks to increase the required CE for the SCR system to 0.125, or 37.5 percent in a highly cyclical, high particulate process, and there is no basis in the record supporting the EPA's conclusion that this emissions limit or level of control is feasible. The commenter adds that LMFs face identical issues.

Commenter (0504) continues, the EPA's recognition that steelmaking facilities utilizing EAFs and argon oxygen decarburization represented a distinct category of sources, separate from BOFs, under section 111 of the CAA is similarly longstanding. Steel manufacturers using

EAFs were first designated as a source category in 1975], and manufacturers using AODs were added in 1984. The EPA recognized that BOFs and EAFs were very different types of emissions sources and therefore regulated them separately. After Congress enacted the 1990 CAA Amendments, the EPA was required to develop technology-based standards for source categories that emit hazardous air pollutants (HAPs). As with the EPA's longstanding delineation of the steel manufacturing sector under the Agency's NSPS regulations, the EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) recognized that integrated steelmaking facilities and EAF steel producers have different material inputs, different emissions units, different emissions profiles, and different emissions control opportunities. For nearly two decades, the Integrated Iron and Steel NESHAP has imposed HAP emissions limitations on "new and existing sinter plants, blast furnaces, and basic oxygen process furnace (BOPF) shops." And since 2007, the EPA has delineated and separately regulated under subpart YYYYY those EAF steelmaking facilities that are area sources of HAPs. This longstanding delineation is based on the EPA's interpretation that a "category" of sources for purposes of section 112 "is a group of sources having some common features suggesting they should be regulated in the same way and on the same schedule."

Commenter (0308) states there are only two EAF steel facilities in Virginia and due to the de minimis impact to downwind receptors, this source category should not be regulated.

Commenter (0504) concludes, indeed, the administrative record for the proposed FIP clearly reflects that integrated steelmaking facilities operate wholly distinct emissions units that are far larger than EAFs and result in 33.5 times greater NO_X emissions intensity than EAFs. But by grouping multiple diverse segments of the steel manufacturing sector based upon their collective inclusion in a 4-digit NAICS category (which is only relevant as a business and economic accounting construct) rather than their type of emissions activity, NO_X emissions intensity, and potential emissions control opportunities, the proposed FIP's screening analysis simply ignored those important distinctions and erroneously identified EAF steel producers as significant contributors of NO_X to downwind receptors. Had the Agency's proposed FIP abided Congress' directive to impose SIP and FIP requirements based on "type of emissions activity," and followed the emissions-based categorization that the EPA utilized for decades in the relevant steel industry NSPS and NESHAP rules, it would have recognized that EAF production facilities cannot be linked to downwind receptors in the same manner as integrated iron and steel facilities because EAF's utilization of electricity to produce molten steel eliminates the largest NO_X-emitting operations from the steelmaking process at its source.

Commenter (0298) adds the EPA establishes an emissions rate in lb/ton of steel, which is not made in ferroalloy facilities. The EAFs employed at ferroalloy smelting facilities are not the type of EAFs covered by the EPA's proposed definition of EAFs (*i.e.*, "a furnace equipped with electrodes used to produce carbon steels and alloy steels primarily by recycling ferrous scrap."). 66 Fed. Reg. at 20181. Ferroalloy manufacturing operations do not involve "ferroalloy 'additions'" to finished products, as the EPA represents. See Proposed Non-EGU Sectors TSD, at 28 [2]. At best, the EPA's attempt to regulate EAFs at ferroalloy manufacturing facilities under the proposed rule is ambiguous, and, therefore, arbitrary and capricious. If the EPA does intend to regulate NO_X emissions from EAFs at ferroalloy facilities the difference in design and operation of ferroalloy EAFs render the EPA's proposal inappropriate.

Commenters (0336, 0359) state the assumptions that SCR or other NO_X control should work on EAFs and coke ovens, may be correct. However, such technology transfers generally increase costs of controls significantly. For example, on EAFs equipped with positive pressure baghouses and without stacks, SCR would need to be installed prior to the baghouse or stacks would need to be constructed. Either situation would increase the cost of the control device beyond what would typically be calculated. It is unclear if the marginal cost threshold of $7,500 per ton includes such technology transfer considerations for EAFs and coke ovens.

Commenter (0345) seeks clarification from the EPA that the proposed rule is limited to ferroalloy manufacturing operations that are part of an integrated iron and steel manufacturing facility. The language of the proposed rule could be interpreted to include independent ferroalloy manufacturers that are not part of an integrated iron and steel manufacturing facility, as the applicability provision refers to any "emissions unit at an iron and steel mill or ferroalloy manufacturing facility[.]" 40 C.F.R § 52.43(b), 87 Fed. Reg. at 20181.

Commenter (0405) states the EPA incorrectly identified "Taconite Production Kilns" as affected units under the Iron and Steel Mills and Ferroalloy Manufacturing category in the proposed FIP. First, taconite production facilities have a different NAICS code than what the EPA described in Table III.A-1-Regulated Groups in the proposed FIP. The proposed FIP listed NAICS code for Iron and Steel Mills and Ferroalloys Manufacturing as 3311. However, the NAICS code for Iron Ore Mining (taconite) is 212210. Taconite production facilities are not even in the same overall NAICS sector which is signified by the first two digits – 21 for mining, quarrying, and oil and gas extraction; 33 for manufacturing. Second, commenter (0405) understands that the EPA noted in the proposed FIP that the NAICS code listings are not meant to be exhaustive. However, it would be a significant departure from past practice for the EPA to consider taconite production facilities as a component of an iron and steel mill. The EPA has historically referred to iron and steel mills as integrated iron and steel manufacturing facilities comprised of blast furnaces, BOFs, electric arc furnaces, finishing operations, etc., not raw material providers such as taconite producers. In fact, the EPA describes this distinction in multiple publications for which examples can be found here: [a, b, c]. For these reasons, commenter (0405) requests that the EPA clarify in the final FIP rule that taconite production facilities are not applicable non-EGU sources and are not subject to non-EGU emissions reduction requirements.

Commenter (0405) provides a few illustrative examples of an extensive list of critical issues in the proposed FIP that reflect a lack of understanding of the iron and steel sector:

- The proposed FIP suggests that the steel industry is subject to a 3-hr average in one location, and a 30-day rolling average in another location [2]. The difference in the degree of stringency between a 3-hr and a 30-day average emissions limit is well understood by the EPA as evidenced by discussions in rulemakings for NSPS subpart Da and Db, which specify 30-day averaging periods.

- Table VII.C-3 of the preamble [87 FR 20145] and Table 1 to Paragraph (c) of the proposed amendments to § 52.43 [87 FR 20181] each specifies an emissions limit of

0.15 lb/ton of coal charged for Coke Oven charging. However, Table I.B-4 of the preamble [87 FR 20046] specifies a limit of 0.6 lb/ton coal charged for Coke Oven charging and coking.

- Table VII.C-3 of the preamble [87 FR 20145] specifies that the starting point for the coke pushing emissions limit is SunCoke Middletown's limit of 0.02 lb/ton coal. However, the applicable NO_X emissions limit cited in the proposed FIP for SunCoke Middletown is not for pushing; it is 0.019 lb per ton of coal charged [4].

- Table 1 to Paragraph (c) of proposed amendments to § 52.43 [87 FR 20182] includes an emissions limit for Boilers firing coal, blast furnace gas, and coke oven gas. However, Table I.B-4 of the preamble [87 FR 20046] and Table VII.C-3 of the preamble [87 FR 20145] only include limits for Boilers firing coal without mention of blast furnace gas or coke oven gas.

- Table 1 to paragraph (c) of proposed amendments to § 52.43 [87 FR 20182] cites the Minnesota FIP applicable to Taconite Production Kilns as 40 CFR 52.1183 which is the Michigan FIP making it unclear to which units EPA intends for the rule to apply.

Commenter (0376) states the proposed rule includes limitations for charging and coking operations and pushing operations at coke ovens. The EPA has not defined terms such as charging, coking, and pushing in the proposed rule; thus, the rule does not provide clarity on the processes/ systems or emissions release points (*i.e.*, fugitive vs. point source) covered by the rule. The NO_X emissions from coke oven-related processes are generated and vented to the atmosphere in a different manner based upon the type of coke oven battery. The EPA failed to consider these differences in establishing these proposed NO_X standards for coke ovens, and in doing so, would impose ineffective controls for certain previously established source types / activities (*e.g.*, charging, coking, underfire, and pushing). The difference in coke oven battery design and operation has long been recognized by the EPA, as can be seen in the National Emission Standards for Coke Oven Batteries at 40 CFR part 63 subparts Land CCCCC (standards for pushing, quenching, and battery stacks) which set drastically different standards based upon the type of coke oven battery.

Commenter (0416) notes the applicability section also includes "each BOF Shop containing two or more such units that collectively emit or have the PTE 100 tpy or more of NO_X." Commenter (0416) asserts that there is no reason to treat operations within a BOF Shop differently than other emissions units, and "accumulate" otherwise minor emissions units for the purposes of the 100 ton per year applicability trigger. Doing so could arguably result in the need to install controls on otherwise minor sources. Applicability for operations within the BOF Shop should therefore be based on a 100 tpy threshold for each individual affected unit, consistent with every other regulated emissions unit. As such, commenter (0416) requests that the EPA revise the applicability section to read: "The requirements of this section apply to each new or existing affected unit at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the PTE 100 tpy or more of NO_X, and that is located within any of the states listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such state(s)." Under this approach, the definition of "BOF Shop" is unnecessary and should be deleted.

Commenter (0798) states that it appears the proposed rule will only cover emissions units which are individually under 100 tpy in the case of facilities with a Basic Oxygen Process Furnace, for which the proposed rule would aggregate emissions from the "BOF Shop" for purposes of determining the proposed rule's applicability to units in the "BOF Shop." The commenter states that the EPA should further clarify what is unique about BOF operations that require them to be aggregated for applicability purposes rather than each emissions unit being subject to a 100 tpy applicability threshold like other furnaces. The commenter also states that because the proposed rule does not contain any NO_X emissions standard applicable to a BOF Shop as a whole, the activities listed as constituting a BOF appear to include activities that are not one of the furnace types regulated under the proposed rule, and the processes noted as constituting a BOF Shop do not appear to be the type of activities that each have separate stacks, the final rule should clarify how a BOF Shop will demonstrate compliance with the emissions limit in the rule.

Commenter (0798) states that the proposed rule should clarify what if any limit is applicable to galvanizing furnaces. The commenter remarks that the Proposed Non-EGU Sectors TSD mentions galvanizing furnaces several times, often in the same context as annealing and reheat furnaces, and the TSD also distinguishes between reheat, annealing, and galvanizing furnaces as separate types of units. However, the commenter notices that the final rule includes different limits for annealing furnaces and reheat furnaces but does not include a separate galvanizing furnace limit. Thus, the commenter asserts that the EPA should clarify whether galvanizing furnaces are intended to be included under the limits applicable to reheat furnaces, annealing furnaces, or neither, including appropriately detailed rationale.

Commenter (0798) believes the EPA has failed to provide support in the proposed rule or accompanying technical documents to show that these required emissions reductions are actually achievable or, even if they were, how they would result in any measurable improved ozone air quality in downwind states. In many instances equipment and fuels within the steelmaking industry are already low NO_X so reductions are not likely to be achieved; and if any further reductions were technologically feasible, they would be cost prohibited as explained in the Trinity Report and the Barr Report. For instance, the proposed rule the EPA proposes "[f]or a vacuum degasser, NO_X is not generated in the process and so NO_X control cannot be applied there despite the EPA's proposed control. And for an LMF, the EPA proposes low NO_X burners as a control technology, but there are no burners in an LMF." Again, in its rush to regulate, the EPA has proposed a fatally flawed rule that, if promulgated, would lead to illogical, infeasible results at great costs without a required showing of favorable impacts in the downwind states. That being said, U.S. Steel is committed to working with the EPA on sound, proven sensible solutions that are technologically and economically feasible and result in measurable ozone improvements in downwind states if, and only if, the EPA first demonstrates and shows that the iron and steel industry interferes with ozone attainment in downwind states, which it has not done so in the proposed rule or its purported supporting documents.

Commenter (0523) states the EPA is correct in not imposing emissions limits on non-recovery/heat recovery coke plants due to significant differences compared with traditional byproduct cokemaking that require different regulatory treatment. Commenter's (0523) non-recovery/heat recovery cokemaking process is unique and presents numerous environmental advantages, including minimizing emissions of hazardous air pollutants and, more importantly for purposes of the proposed rule, minimizing NO_X emissions. In fact, the waste gas stream of a non-recovery coke plant contains less than 5 percent of the NO_X present in the waste gas of an average byproduct plant based on EPA data. Other EPA rules differentiate between non-recovery/heat-recovery coke plants and byproduct coke plants, and the Agency would be correct for doing the same here by clearly exempting non-recovery/heat-recovery plants from regulation when finalizing the proposed rule. These factors provide further evidence that the proposed rule does not apply to Commenter's (0523) facilities, and also demonstrates that if the EPA were to finalize a rule that applies to such facilities, it would exceed the EPA's authority and be arbitrary and capricious under State Farm.

Commenter (0523) manufactures coke by heating metallurgical coal in a refractory oven, utilizing a staged-combustion process to provide the heat required to release the volatile components in the coal and transform the coal into coke. The commenter's first plant was built in 1962 in Vansant, Virginia based on the Jewell-Thompson oven design. For more than three decades, it was the only non-recovery coke plant in the United States. Unlike conventional "byproduct" coke plants that recover volatile material from coal, the commenter's facilities use efficient, modern technology designed to combust the coal's volatile components without the use of burners or a separate heating chamber. It is worth noting, all of the commenter's facilities are considered "non-recovery" coke plants because they do not recover these chemicals from the coal. Most of their facilities are also known as "heat recovery" coke plants, which use the resulting waste heat from the process to create steam or electricity.

Commenter (0523) continues, in the non-recovery coke making process, a Pusher-Charger Machine (PCM) charges a horizontal bed of coal into the side of a hot oven using a leveling conveyor. Immediately after charging, the coal absorbs heat from the surrounding refractory, driving volatile matter from the coal bed. Air is first introduced into the oven crown, combusting the volatile matter from the coal and transferring heat from combustion back into the refractory. Partial combustion of volatiles occurs in the oven crown above the bed. Gases are then drawn through downcomers into sole flues beneath the oven floor, where more air is introduced to further the combustion process. This permits carbonization from the top and bottom at equal rates. The gases are then drawn back up through uptakes into the common tunnel where any remaining uncombusted gases are oxidized. This is a staged combustion design consisting of three stages—the oven crown, sole flues, and common tunnel. In addition, non-recovery/heat-recovery cokemaking does not require an external heat source such as burners to heat the ovens.

At most of commenter's (0523) facilities, the flue gases are then drawn into the crossover duct, which directs them into HRSG where the residual heat is extracted, and steam is produced. At those facilities, the non-recovery process is called "heat-recovery" cokemaking. After passing through the HRSGs, the cooled flue gas is directed to a flue gas desulfurization system (FGD) that consists of a spray dry absorber (SDA) and a baghouse prior to being exhausted through a main stack. In the SDA, atomizers create a fine mist of droplets of lime slurry (aqueous calcium hydroxide or Ca(OH)2). The SO_2 in the gas diffuses into the droplets and reacts to form $CaSO_4$. The droplets dry out in the SDA, leaving solid particles of $CaSO_4$ and unreacted lime. These particles are collected by the baghouse and sent off-site for disposal.

Commenter (0523) states the coke ovens are maintained under negative pressure by induced draft fans located downstream of the FGD. The induced draft fans provide negative pressure at the ovens to keep the volatile matter and combustion gases inside the system. In addition, each HRSG is matched with a bypass vent stack, which remains closed during normal facility operations. During certain maintenance conditions that prevent flue gas transport to the main stack, the vent stack lid will open to allow the combusted flue gas from the associated ovens to exhaust through the vent stack while maintaining negative pressure in the ovens, which cannot be shut down.

Commenter (0523) notes it takes approximately 48 hours for the non-recovery coking process to be completed. At the end of the coking cycle, the hot coke is pushed out of the oven onto a “flat push hot car” equipped with a multiclone dust collector at some facilities or a hot car partially enclosed by a shed at other facilities. The coke is transported by the hot car, which operates on rails, to a quench tower where the incandescent coke is cooled, or quenched, with water. The cooled coke is then transferred via conveyor belt to a screening station.

Commenter (0523) continues, non-recovery coke ovens operate under negative pressure and combust the coal volatiles, adding air from the outside to oxidize volatile matter and release the heat of combustion within the oven system. This has the benefit of virtually eliminating leaks from coke ovens to the atmosphere and minimizing emissions of volatile organic compounds and hazardous air pollutants (HAPs). Any leaks in the system will draw ambient air into the system. Accordingly, coke oven leaks are generally prohibited at non-recovery coke ovens under applicable MACT standards. (see 40 CFR § 63.303.)

Commenter (0523) states, in contrast, the conventional cokemaking process at byproduct plants recovers the coal volatiles and combustion products downstream of the oven chamber and refines them in a separate part of the plant to produce chemicals such as light oil, tar, and ammonia. Byproduct plants also recover coke oven gas released in the coking process for use in oven underfiring and in other areas of the plant. To recover these components, byproduct ovens are maintained under positive pressure, and there is potential for small openings or cracks in byproduct ovens to allow raw coke oven gas and HAPs to leak into the atmosphere. Under the MACT standard, byproduct ovens are typically permitted to leak at a rate of 3-4 percent per battery, and leaks are also permitted from topside port lids and offtakes. (see id. at § 63.302(a)(3).)

Commenter (0523) continues, because of the environmental advantages of non-recovery cokemaking, new “greenfield” coke oven batteries have effectively been required to use non-recovery technology under the MACT standard since 1993. (see id. at § 63.300(b) and § 63.302(b); see also 57 Fed. Reg. 57534, 57536 (Dec. 4, 1992) (“Visible emissions limitations for a new by-product coke oven battery constructed at a new coke plant (‘greenfield’ construction) and the construction of a new battery at an existing coke plant if it results in an increase in the plant’s coke capacity would be based on the emissions control performance achieved by nonrecovery coke oven batteries, which are 0.0 percent leaking doors, topside port lids and offtake system(s)[.]”)). Another environmental advantage for non-recovery coke plants is that they are subject to a zero-discharge limit for process wastewater pollutants under applicable effluent limit guidelines (40 CFR § 420.12(c)). Water from the quenching process is recycled until evaporation, and discharges are limited to stormwater runoff and non-process wastewater streams, such as HRSG blowdown water. In contrast, byproduct plants require a wastewater treatment facility to facilitate the various chemical production processes. In addition, because of the vast differences between non-recovery coke plants and byproduct coke plants, there are significant differences in how the plants are regulated under applicable MACT standards. Besides the different requirements for coke oven door leaks described, there are different standards for charging the ovens. Compare 40 CFR § 63.302(a)(3)(v) with § 63.303(d). At byproduct plants, there are standards for bypass/bleeder stack flare systems as well as collecting mains, whereas there are no such units at non-recovery plants. See id. at §§ 63.307 and 63.308. There are different standards for pushing emissions from byproduct plants and non-recovery plants. See id. at §§ 63.7291-63.7293. Finally, unlike non-recovery plants, there are unique MACT requirements for soaking emissions and from battery stacks at byproduct plants. See id. at §§ 63.7294 and 63.7296. Non-recovery coke plants and byproduct coke plants are effectively different industries for regulatory purposes.

Commenter (0523) continues, the non-recovery cokemaking process also provides significant advantages in minimizing formation of NO_X emissions. Fundamental differences in the design and operation of non-recovery and byproduct coke plants result in our plants containing less than 5 percent of the concentration of NO_X in the flue gas compared with a byproduct plant. The average SunCoke flue gas NO_X concentration is only 37.82 ppm based on the most recent stack test at each of commenter (0523) plants. In contrast, according to the EPA's TSD for the proposed rule, uncontrolled NO_X emissions from byproduct coke plants range from 254 to 1452 ppm, with an average value of 802 ppm. See Proposed Non-EGU Sectors TSD, at 29-30. Even if byproduct coke plants successfully reduced NO_X emissions by 90 percent, this represents final emissions of 25 to 145 ppm, with an average of 80 ppm—well over SunCoke's current 37.82 ppm average performance. The EU has established Best Available Techniques ("BAT") levels for NO_X at 350-500 mg/Nm3 for new or substantially revamped plants (less than ten years old) and 500-650 mg/Nm3 for older plants with well-maintained batteries incorporating low-NO_X techniques. (See id. at 34). These BAT levels are substantially higher than the current performance of SunCoke's nonrecovery/heat recovery coke plants.

One reason commenter's (0523) process generates such a minimal quantity of NO_X is because staged combustion is inherent to the non-recovery cokemaking process. Staged combustion controls NO_X by limiting the oxygen present to control and suppress peak temperatures where NO_X formation primarily occurs. Non-recovery coke ovens use three discrete regions for staged combustion of the coal volatiles—the crown, the sole flues, and the waste heat common tunnel. After coal is charged into the oven, the crown is the first stage of air addition. This operates in a reducing atmosphere where minimal oxygen is present for NO_X formation. The sole flues receive secondary air and operate in a reducing or oxidizing atmosphere as dictated by the oven gas rates. NO_X formation is minimized in the sole flues by controlling the temperatures. The final stage is the common tunnel afterburner, which is always operated in an oxidizing mode. NO_X formation is limited in this region through the introduction of tertiary air to cool the gases below temperatures where NO_X is formed.

Commenter (0523) states their non-recovery oven combustion process controls peak flame temperatures, minimizing the formation of NO_X. The process is equivalent to air staging in low NO_X burners for a boiler, whereby combustion air is separated into primary and secondary flow sections, which controls air and fuel mixing at each burner to reduce the peak flame temperature, forming significantly less NO_X from nitrogen gas (N2). See J.L. Sundholm, et al., Manufacture of Metallurgical Coke and Recovery of Coal Chemicals, at 543 (The AISE Steel Foundation, Ch. 7, 1999) ("With this unique heating system with nine downcomers per oven and staged combustion air supply, a uniform temperature profile is achieved . . . In addition, the multi-staged heating system with air introduced at different levels leads to the formation of lower NO_X levels in the waste gas.").

Commenter (0523) continues, another reason for the low levels of NO_X at non-recovery/heat-recovery coke plants is that nonrecovery ovens do not require an externally-fueled heat source such as burners. The Agency acknowledges this important difference with byproduct plants in the proposed rule's supporting documents. See Technical Support Document at 24 ("In facilities using the non-recovery coking process, the ovens are heated differently from recovery coking operations such that no external heat source is required[.]"). In a non-recovery coke oven, the volatile fraction of the coal migrates from the coal bed, and the coal bed is converted to a coke bed over the coking cycle. There is no external fuel. The coal undergoing the coking process supplies all of the heat necessary for cokemaking. Note that a gas lance can be applied externally to a non-recovery coke oven during maintenance and similar conditions to keep the oven walls sufficiently hot. This is important to prevent thermal spalling, which would compromise the integrity of the oven structure and its negative pressure design. Unlike non-recovery ovens, byproduct coke ovens have a distinct combustion chamber in between—and separate from—each coke oven. Burners are located in these combustion chambers and use coke oven gas and/or natural gas to heat the walls of the coke oven. This results in a considerably higher concentration of NO_X compared with the nonrecovery process.

Commenter (0523) continues, at a non-recovery coke plant, charging is a negligible source of NO_X, as indicated by the absence of an AP-42 emissions factor for NO_X emissions from nonrecovery plant charging operations. See EPA, Compilation of Air Pollutant Emission Factors, AP-42, at 12.2-32 (Table 12.2-21) (Vol. I, Ch. 12, Sec. 12.2, 5th ed. 2008). During charging, the PCM charges a horizontal bed of coal into the side of the oven, which is being operated at negative pressure, using a leveling conveyor. Each PCM is equipped with a traveling hood/baghouse system that controls fugitive particulate from the coal as it is charged into the ovens. No combustion takes place in the PCM. To the best of commenter's (0523) knowledge, the PCM baghouse stack has never been tested for NO_X, nor has any environmental agency even considered regulating NO_X emissions from non-recovery plant charging operations. Emissions control is only necessary for the fugitive dust generated by charging significant volumes of coal.

Commenter (0523) states by contrast, a byproduct coke plant charges coal into the top of the oven battery— not the side—using a different piece of equipment, called a larry car. Because the ovens operate under positive pressure, standpipes can open due to overpressure, which emit NO_X into the air from combustion during charging. Jumpers and an advanced seal system are available to mitigate these charging emissions, but they are not required at all plants. In addition, byproduct coke plants have battery stacks which release combustion emissions from the oven's fuel system. If there are internal oven wall cracks, the battery stacks will emit more NO_X due to poorly-combusted additional nitrogen-bearing fuel leaking into the combustion chamber from the coal undergoing the coking process.

Commenter (0798) states in the proposed rule, the EPA upends and departs from years of prior precedent and knowledge with a couple of ambiguous, and even illogical, paragraphs. Yet, this proposed technology has not been shown to be available or feasible for these emissions sources. While commenter (0798) has many concerns over the proposed rule as it would apply to coke batteries, the first overarching comment, as a general matter, is that the Clairton Plant is NOT integrated physically with any iron and steel facilities (*e.g.*, blast furnaces, BOFs, etc.) The facility is a physically separated form and is not part of any "stationary source" consisting of U.S. Steel's integrated iron and steel facilities and operates under the NAICS code 3241, "Petroleum and Coal Products Manufacturing." Thus, grouping coke in the iron and steel sector is inappropriate – especially when Congress and the EPA have historically considered the processes unique and separate in other rulemaking efforts. If the coke industry were properly classified in the NAICS code 3241, the charging and pushing would not be included - which is much more logical than what the EPA attempts to do in the proposed rule.

Commenter (0523) notes the EPA did not analyze the emissions from non-recovery/heat recovery coke oven batteries, the impact of those emissions on downwind receptors in nonattainment areas, or the costs of potentially controlling those emissions. This indicates that the EPA did not intend to regulate SunCoke's coke plants because it never determined that such facilities significantly contribute to downwind nonattainment. If the EPA does not make the necessary clarifications or nevertheless decides to apply the rule to SunCoke, the Agency will have exceeded its statutory authority and the rule would be arbitrary and capricious.

Commenter (0523) states the background documents of the proposed rule are lacking any analysis of emissions from, or the rule's impact on, SunCoke's non-recovery/heat-recovery coke plants. When the EPA conducted its assessment of emissions from non-electric generating units ("non-EGUs"), it aggregated emissions inventory data into industries defined by 4- digit NAICS codes. See 87 Fed. Reg. at 20083-84; EPA, Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (EPA-452/D-22-001) (Feb. 2022) ("Regulatory Impact Analysis"), at 4-23. In a two-step process, the EPA determined that a number of sources within NAICS code 3311 for the Iron and Steel Mills and Ferroalloy Manufacturing category, including certain coke oven batteries, should be regulated because they significantly contribute to downwind nonattainment and can reduce emissions within the Agency's marginal cost threshold. See Regulatory Impact Analysis at 4-23.

Commenter's (0523) facilities are classified under NAICS code 324199 not 3311. NAICS code 3241xx for Petroleum and Coal Products Manufacturing is regulated under the proposed rule as a Tier 2 category in which certain large boilers are regulated. However, commenter's facilities do not include any boilers at all, which is evident in the EPA's spreadsheet entitled "Transport Proposal – Tier 2 Boiler Analysis 0 03-16-2022; All NAICS Units – 2023 Industry Identification Analysis" (Regulations.gov, Document ID EPA-HQ-OAR2021-0668-0225), which does not identify any SunCoke plants with boilers. Moreover, none of SunCoke facilities (appear in the EPA's "Transport Proposal - Screening Assessment Non-EGU Facility and Emissions Unit Lists - 03-18-2022" (Regulations.gov, Document ID EPA-HQOAR-2021-0668-0191). In the EPA's spreadsheet used for modeling inputs, all SunCoke plants are correctly identified as NAICS code 324199, not 3311. See EPA, Summaries of Point Source Emissions Used in Air Quality Modeling (Regulations.gov, Document ID EPA-HQOAR-2021-0668-0105). As a result of this classification, the EPA never modeled potential emissions reductions or studied costs for SunCoke's plants when developing its analyses for the proposed rule. The EPA never determined that non-recovery/heat-recovery coke oven batteries significantly contribute to ozone nonattainment in downwind states.

Commenter (0798) states the EPA failed to perform any coke making stakeholder engagement whatsoever in advance of the proposed rule. This lack of stakeholder engagement has contributed to the EPA's failure to understand the by-product coke making process. The docket associated with the proposed rule is extremely light on any technical support for the proposed NO_X limits to charging and pushing, and it is apparent that what little information is provided in the docket is not representative of the by-products coke making process. In its rush to regulate, the EPA is relying on scant information from heat recovery coke making which is fundamentally different and not representative or applicable to by-products coke making. Furthermore, and most significantly, there are several inconsistencies throughout the proposed rule.

Commenter (0523) notes the Regulatory Impact Analysis also says virtually nothing about any type of coke oven batteries. It merely indicates that the rule is proposing emissions limits within the Iron and Steel Mills and Ferroalloy Manufacturing industries based on lb/ton coal charged and lb/ton coal pushed due to the categorization of certain operations, presumably coke ovens, as "boilers and furnaces" emissions units. See Regulatory Impact Analysis at ES-11 (Table ES-3) and 4-4 (Table 4-1). However, SunCoke's coke ovens are not classified as "boilers" or "furnaces" in any existing state or federal rule, particularly in the non-recovery/heat-recovery coke industry where there is no external heat source applied to the ovens. This "boiler and furnace" categorization would be even more misguided in the context of SunCoke's pushing and charging operations— seemingly the primary target of the proposed rule for coke plants—because limited to no combustion takes place in SunCoke's hot cars and pushing charging machines ("PCMs"), as explained in greater detail in Section III.B.3.

Commenter (0798) continues, the proposed rule, as it applies to charging at coke plants, is inconsistent and illogical. The NAICS code of 3311 is not applicable to stand-alone coke plants. In addition to this inconsistency (where the EPA categorizes coke into NAICS code of 3311), in Table I.B-4 of the proposed rule, the EPA proposes a NO_X charging limit of 0.6 lbs/ton of coal charged for coke ovens (charging and coking). However, the reference to including "coking" and the 0.6 lbs/ton of coal charged limit is not explained or supported in the Proposed Non-EGU Sectors TSD. Furthermore, it is unclear as to what aspect of the "coking" process the EPA intends to regulate, where it intends to regulate, and how it intends to regulate "coking" as noted in this Table – as the docket is void of any supporting information. To add further inconsistencies, in the TSD, the EPA attempts to explain the process, but by doing so, it creates additional ambiguities: "Often situated in front of a bank of coke ovens, a separate machine is responsible for opening the coke oven doors, charging and pushing the raw material, and closing the oven again. This machine is often termed a larry car, or charging and pushing machine, among other terms.” This statement does not accurately describe charging and pushing in a by-products coke oven. While a larry car is used in by-products ovens, it is separate and distinct from pushing and is done at the top of the oven. Thus, in a by-products battery, a weighed amount or specific volume of coal is discharged from the bunker into a larry car - a charging vehicle that moves along the top of the battery. The larry car is positioned over the empty, hot oven (called "spotting"), the lids on the charging ports are removed, and the coal is discharged from the hoppers of the larry car into the oven. To minimize the escape of gases from the oven during charging, steam aspiration is used at most plants to draw gases from the space above the charged coal into a collecting main. In addition, charging is not known to emit any appreciable amounts of NO_X. It is also not clear on how one would install and operate an SCR on a moveable larry car as the EPA seems to propose.

Commenters (0523, 0798) note the EPA attempts to explain: “For coke ovens (charging) and coke ovens (pushing), the EPA based the emissions limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50 percent based on current permit emissions limits and production-based push/charge cycles. The EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X practices, staged pushing and hood configurations, and potential use of add-on NO_X control technology at larry cars and pushing/charging machines, including potential use of low- NO_X burners, flue gas recirculation, and/or the addition of SCR to mobile hoods and PM control devices.” Yet, the on-line version of AP-42 refers to a NO_X emissions factor for charging of 0.03 lb/ton of coal charged, not the 0.3 lb/ton referenced in the preamble of the proposed rule, where the EPA explains that the proposed NO_X limit of 0.15 lb/tons of coal charged is based upon an assumption of “50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP-42 0.3 lb/ton emissions factor.” It is unclear if the EPA’s reference to 0.3 is in error; or if the AP-42 emissions factor is in error. In any case, clarification is needed.

Commenter (0422) submits that boilers that burn fuel as a “beneficial reuse” or as a benefit to the environment should be excluded. One of our site’s is part of the “Sustainable Growth” Landfill Methane Outreach Program (LMOP). This is a voluntary program to reduce emissions associated with landfill gas by using it in a beneficial way, such as fuel for a boiler. These boilers are providing a beneficial environmental value that is not considered in the proposed rule and should not be subject to additional controls.

Commenter (0523) request a clear exemption for “non-recovery” and “heat-recovery” coke oven batteries in the applicability section of the final rule. Commenter (0523) also requests the removal of the reference to “pushing charging machines” in the text of the final rule because it is equipment that is unique to our operations. Commenter (0523) found a number of ambiguities and contradictions in the proposed rule regarding these limits in the context of our plants. It is worth noting, it is very challenging for SunCoke to understand what emissions limits are being proposed, but the commenter can say generally that the proposed emissions limits would be unprecedented if they were applied to non-recovery coke plants. Moreover, none of the control measures cited in the proposed rule’s TSD from various state NO_X RACT requirements appear to apply to any coke plants, but the commenter is certain that they are not referring to any non-recovery coke plants.

Commenter (0287, 0336, 0405, 0504) states the EPA specifies applicability of the proposed FIP to the Iron and Steel sector in one location as any individual unit that emits or has a PTE of greater than or equal to 100 tpy and two or more Iron and Steelmaking units at a facility, which, when combined, emit or have a PTE of greater than or equal to100 tpy. Elsewhere in the proposed FIP, the EPA specifies applicability to the Iron and Steel sector as on individual units over 100 tpy except in the BOF Shop, where the PTE of emissions units are combined for applicability. The impact of the proposed regulation would be substantially different depending on which applicability requirement applies. Because all other sectors are subject to the 100 tpy PTE threshold for individual units, it is arbitrary and capricious that the Iron and Steel sector be treated differently than other sectors.

Commenters (0287,0336, 0405, 0504) are concerned the proposed Section 42.43(b) could be misread as applying to each iron and steel mill or ferroalloy manufacturing facility that directly emits or has the PTE 100 tpy or more of NO_X and that is located within any of the states listed in § 52.40(a)(1)(ii). Indeed, the EAF Steel Associations are aware of numerous instances in which permit writers and enforcement personnel in states and the EPA regional offices have interpreted regulatory text in a manner inconsistent with the meaning ascribed by the EPA personal that drafted the regulatory text. As such, commenter (0504) recommends that the EPA redraft proposed Section 42.43(b) as follows:

The requirements of this section apply to:

(1) each new or existing emissions unit that:

(A) directly emits or has the PTE 100 tpy or more of NO_X; and

(B) 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) (2) is located at an iron and steel mill or ferroalloy manufacturing facility.

(2) each BOF Shop containing two or more new or existing emissions unit that collectively emit or have the PTE 100 tpy or more of NO_X, and that is located within any of the states listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such state(s).

Commenter (0405) states using incorrect and/or undocumented limits as a starting point, the EPA applies an arbitrary removal efficiency based on a technology that in most instances has never been demonstrated in the Iron and Steel sector, namely, SCR and SNCR. SCR and SNCR have never been demonstrated on blast furnaces, BOFs, EAFs, ladle/tundish preheaters, reheat furnaces (successfully), vacuum degassers, LMFs, coal charging, coke pushing, or multi-fuel boilers and in each case are not technically feasible. Instead, the assumed removal efficiencies used by the EPA in Table VII.C-3 to establish enforceable limits for many of the batch steel making processes are arbitrarily extrapolated from SCR applications in other industries, *e.g.*, steady state continuous electric utility boilers. Commenter (0405) takes exception with the EPA's application of arbitrary removal efficiencies based on ranges demonstrated in other dissimilar industries to the Iron and Steel sector without providing any actual data or evidence of technical feasibility.

Commenter (0798) states some of the emissions units and US Steel's integrated steel facilities to which the EPA would have the SCR emissions control applied would require significant preconditioning and heating of the exhaust gas to make it amenable to SCR. The conditioning and heating of exhaust gas prior to being able to utilize a SCR would not only be difficult to design and operate but would also require increased use of natural gas and have other impacts and costs not considered by the EPA. The increased combustion of natural gas that would be required to condition the exhaust gas for a SCR would increase various emissions such as CO2, PM, SO_2 and even NO_X. The increase in NO_X clearly goes against the purpose of the proposed rule. Nor did the EPA consider the design and infrastructure that would be needed for the conditioning and preheating or the environmental impacts associated with the increases in emissions associated with conditioning and preheating. These issues were overlooked or not recognized by the EPA during the development of the proposed rule.

Commenters (0280, 0798) explain, LMFs are used in the steel industry to increase the liquid metal temperature for casting and to produce steel grades by adding alloys. The LMF process is a batch process and since there is no combustion source (except for de minimis amounts associated with the consumption of electrodes by oxidation with oxygen in capture air) there is minimal NO_X emissions. Commenter (0280) notes in the Proposed Non-EGU Sectors TSD, the EPA says that emissions controls on LMFs could include "low NO_X burners" and SCR [19]. This statement reflects a fundamental misunderstanding of what an LMF is. An LMF is a ladle (the "L" in LMF) that is placed under a roof through which an electrode or electrode(s) are inserted and an arc introduced to adjust temperature. LMFs may also have slots to add alloys or other materials, to insert an oxygen lance, and possibly a porous plug to allow argon stirring. LMFs do not, however, have burners because the ladle is mobile (*e.g.*, picked up and moved from place to place), wholly precluding use of fixed natural gas burners.

Commenter (0280) argues, otherwise, LMFs resemble EAFs in terms of their control challenges. Like EAFs, LMFs are significant particulate generators pre-control, likely in the 10-20 lb/ton of steel range. This quantity of particulate likely renders the application of pre-particulate controls for NO_X removal infeasible. The exhaust stream beyond the particulate control device creates the same temperature adjustment requirement (penalty) as discussed for the EAFs, except perhaps somewhat greater because LMFs typically have somewhat cooler exhaust. To properly operate an SCR after the particulate control device, natural gas combustion would be necessary to increase the flue gas to optimal temperature for performance and would increase emissions of GHGs, CO, NO_X, and other air pollutants.

Commenter (0280) continues, the EPA's preamble and Proposed Non-EGU Sectors TSD appear to misapprehend the nature of the majority of annealing furnaces. Commenter (0280) uses predominantly "bell annealing" furnaces. These furnaces consist of a base, upon which steel coils are stacked. A "bell" is placed around the coils. A furnace shell is then lifted and placed over the bell. The atmosphere inside the bell may or may not be evacuated. The furnace shell is fired until the desired temperature is reached and then the furnace shell is removed and the steel either left in the bell or a cooling bell added. The critical point is that the furnace is physically picked up and moved by crane from place to place. This crane lifting process is incompatible with add-on emissions controls, rendering them technically infeasible.

Commenter (0798) notes annealing furnaces go through a series of heating and cooling process allowing hard metals to have various ductility and strength. Annealing furnaces are designed to operate in a batch or continuous function. Continuous Annealing furnaces are the only steelmaking equipment that has been shown to be feasible with the SCR technology. However, SCR is not feasible on batch annealing furnaces. While the SCR technology may be technologically feasible for continuous annealing furnaces it is not cost effective. Trinity Consultants performed a "control cost effectiveness analysis on the Irvin open coil annealing furnace, which showed that the SCR cost effectiveness would be at best $25,630 (2021$). This is well beyond the EPA stated $7,500.

Commenter (0798) adds, the EPA also did not use the proper methodology to set emissions limits for the annealing furnaces. There is additional technical information in the document prepared by Trinity Consultants which states "for annealing furnaces, the EPA started with recent BACT determinations, and then applied an additional 40% reduction without any demonstration of achievability of the proposed limit." These numbers are not based upon proper determinations and the EPA did not provide support for the additional 40 percent reduction found in the proposed rule.

Commenter (0798) states the EPA has a fundamental misunderstanding of vacuum degassing and NO_X emissions (de minimis) associated with the process. Vacuum degassers (VDGs) are used in the steel industry to remove certain gases from the molten steel prior to casting. This helps to produce the desired properties of the finished steel. Degassers can remove hydrogen (H_2), oxygen (O_2), and nitrogen (N_2) that are dissolved in the liquid metal. They are also used to reduce the carbon content of the steel prior to casting to produce an ultra-low carbon product.

Commenter (0798) continues, while not clear from the proposed rule, it would appear that the EPA would intend to include vacuum degassing in the BOF Shop, and therefore, not subject to the triggering 100 ton PTE threshold, and, instead, would inexplicably be included and subject to the proposed limits even if no appreciable reduction would result. The process of the degasser itself does not generate NO_X – and therefore its inclusion in the proposed rule is perplexing. The only NO_X associated with vacuum degassing is NO_X generated by the flare when CO abatement and is a function of adiabatic flame temperature which is related to excess air, fuel usage and flare design. The EPA's has scant support for its inclusion of vacuum degassing and the proposed limit of 0.03 lb/MMBtu on existing permit limits of 0.05 lb/MMBtu. (EPA's entire technical support discussion in the Proposed Non-EGU Sectors TSD for the limit is provided: "For vacuum degassers utilized in secondary steelmaking, the EPA based the limit of 0.03 lb/mmBtu on existing permit limits of 0.05 lb/mmBtu. The EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X technology, including use of selective catalytic reduction." The EPA does not provide any further explanation – and a review of the RBLC does not support the EPA's ambiguous and vague conclusions.

Commenter (0798) states installing emissions control technology on VDGs is not feasible. VDGs are a batch process and has variables in the exhaust gas. Again, due to the de minimis amounts of NO_X peripherally associated with vacuum degasser flares and the low potential reduction of NO_X from installation of SCR technology (even if it were feasible, which it is not) results in a technologically infeasible limit that is not cost-effective. VDGs also are very low in NO_X emissions and do not meet the 100 ton per year threshold in the proposed rule. However, the VGDs are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions

Commenter (0798) explains, Ladle or Tundish preheaters are small natural gas burners that direct fire ladles to keep them warm, dry or preheat them – as an ancillary process and to better preserve refractory. The preheaters are used to dry out ladles and there is no vent or combustion exhaust gas capture. In this case SCR technology is not feasible as there is nothing to add the SCR to at the end of the exhaust. The EPA failed to understand the use of these preheaters and did not make any determination as the feasibility of putting SCR on the ladle or tundish preheaters. If the proposed rule is finalized there would be significant costs in trying to absolutely redesign these preheaters to accommodate the possibility of SCR. Commenter (0798) argues ladle preheaters are such a small potential source of NO_X that there will be no impact from this change on downwind states. Most states already consider this to be an insignificant activity for air emissions and consider it fugitive emissions.

Commenter (0798) argue ladle preheaters are very low in emissions and do not meet the 100 ton per year threshold in the proposed rule. However, the preheaters are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions. Any potential reduction from ladle or tundish preheaters would be minimal and would not be cost-effective. Furthermore, the EPA has not shown how the insignificant NO_X emissions from ladle/tundish preheaters interfere with ozone attainment in downwind states; or how downwind states would have any measurable benefit from the proposed limits. Again, there appears to be a fundamental misunderstanding of the industry and the limitations of the proposed SCR technology to these sources.

Commenter (0345) seeks clarification from the EPA that the proposed rule is limited to ferroalloy manufacturing operations that are part of an integrated iron and steel manufacturing facility. The language of the proposed rule could be interpreted to include independent ferroalloy manufacturers that are not part of an integrated iron and steel manufacturing facility, as the applicability provision refers to any "emissions unit at an iron and steel mill or ferroalloy manufacturing facility[.]" 40 C.F.R § 52.43(b), 87 Fed. Reg. at 20181.

Commenter (0287) references its own engineering cost study for applying SCR to two EAFs and states that the EPA's proposed emissions limit for EAFs is based on a technically and economically infeasible control device.

Commenter (0345) believes the discussion in the preamble and in the supporting documents addresses ferroalloy manufacturing only in the context of an integrated iron and steel manufacturing operation – in effect, as a final stage that is used to "incorporate[] reactive elements . . . to create distinctive qualities in a metal product." Commenter (0345) points to the Proposed Non-EGU Sectors TSD at 27. Indeed, the explanation in the TSD refers only to ferroalloy "additions" at the end of the steelmaking process. Id. at 28. More particularly, the discussion of existing rules that apply to the industry does not even mention the ferroalloy manufacturing NESHAPs (40 CFR part 62, subparts XXX and YYYYYY). Id. at 28-29. Even the proposed emissions limits are phrased as pounds of NO_X per ton of steel. 40 C.F.R § 52.4I), Table 1, 87 Fed. Reg. at 20181.

Commenter (0345) argues if the EPA does intend the proposed rule to apply to independent ferroalloy manufacturing facilities, the record does not provide any legal or factual basis for doing so. The EPA identified affected industries by 4-digit NAIC codes. Both iron and steel manufacturing and ferroalloy manufacturing share the same 4-digit code (3311). However, CCMA and Felman have identified nowhere in the available documents where the EPA evaluated emissions from or available controls for ferroalloy operations that are not associated with an iron and steel manufacturing facility.

- EPA did not consider any federal rules that apply to the ferroalloy manufacturing industry. TSD at 28-29.
- None of the state RACT rules identified in the TSD involve ferroalloy manufacturing facilities. TSD at 42.
- The analysis of emissions and control technology in the TSD does not address independent ferroalloy manufacturing operations. See supra.
- The primary support for that analysis is the Alternative Control Techniques Document for the iron and steel industry (EPA-453/R-94-065 (Sept. 1994) ("ACT"). See TSD at 29-42. That document also does not address the ferroalloy manufacturing industry.
- Additional supporting documents referred to in the TSD – *e.g.*, the Menu of Control Measures (MCM), the EU BAT document, the 1994 STAPPA/ALAPCO menu of options – also do not consider ferroalloy manufacturing industry.
- Even EPA's March 18, 2022, screening analysis does not include any independent ferroalloy manufacturing facilities – even though CCMA's furnaces exceed the 100 tpy NO_X emissions threshold EPA identified as the threshold for regulation.

Commenter (0345) argues the EPA cannot reasonably regulate emissions from submerged EAFs used in ferroalloy manufacturing without first review the emissions from these kinds of operations and the types of control technology that are available for these units.

Commenter (0345) believes if the EPA had included ferroalloy manufacturing facilities in its analysis, that analysis would have demonstrated that the proposed emissions limits are infeasible for these types of operations, and that attempting to retrofit these facilities to even approach the proposed limits would exceed the $7,500 cost-effectiveness threshold by several orders of magnitude. First, the proposed emissions limits on EAFs assume the use of SCR or NSCR. But EAFs used in ferroalloy manufacturing operate very differently than those used in iron and steel manufacturing – in ways that either dramatically increase the cost of SCR/NSCR or preclude those technologies entirely. In particular:

- Both NSCR and SCR require high-temperature reaction zones. At the CCMA and Felman facilities, the necessary temperatures exist only at the uppermost portion of the open furnaces. As the facilities currently exist, however, the physical configuration of this portion of the furnace does not allow for the installation of an SCR/NSCR system at that location. To maintain the temperatures necessary to operate an SCR/NSCR system appropriately, Felman and CCMA would need to heavily insulate the existing process equipment and ductwork that conveys the exhaust gases to the baghouses. Felman and CCMA have performed a preliminary conceptual design for the introduction of an SCR or NSCR system within the ductwork between the furnace and the baghouse, including the insulation necessary to maintain the required temperatures. Given the volume of gases exiting the furnace (which include significant dilution air) and the retention time requirements to ensure the control system operates appropriately, the facilities would need to install new ductwork that would encompass all available free space in the upper part of the furnace buildings – and, indeed, may even require structural changes to the building itself. Such a significant redesign would also affect the facilities' ability to comply with the applicable NESHAPs, which require careful vent gas flow management and appropriately-designed roof vents to ensure the sites comply with the required opacity limits.

- The EAFs used in ferroalloy manufacturing are open furnaces. The furnaces discussed in the background documents are closed furnaces. Closed furnaces have a very different emissions profile, as they do not include significant quantities of dilution air associated with use of an open furnace. Indeed, the volume of vent gases at a ferroalloy manufacturing facility is three to five times larger than the volume of vent gases at an iron and steel foundry (on a per MW basis), which significantly changes the economics of any control system. The existing understanding of SCR and NSCR equipment and application is strictly based on combustion within enclosed reaction zones.

- The dilution air that enters into an open furnace system complicates the treatment of exhaust gases, due to the reduced concentration of NO_X. As a result, these types of operations cannot be expected to achieve the same emissions reduction from an SCR or NSCR system.

- These different emissions profiles are reflected in the different permit limits for ferroalloy manufacturing facilities. The EPA's analysis for EAFs assumes an average current emissions limit between 0.2 to 0.35 lb/ton steel; assuming a 40 percent reduction in NO_X emissions leads to the proposed emissions limit of 0.15 lb/ton steel. TSD at 43. For CCMA's operations, however stack tests and data submitted to the regulatory agencies have established a NO_X emissions factor for ferrosilicon production of 11.73 lb/ton produced – 30-50 times higher than the baseline emissions limits for EAFs used in iron and steel production. For CCMA's operation to meet the 0.15 lb/ton emissions limit in the proposed rule would require more than a 90 percent reduction – well above the 40 percent reduction that the EPA assumes SCR can achieve. Indeed, commenter (0345) knows of no existing technology that could achieve the degree of reduction necessary to achieve the 0.15 lb/ton emissions limit for ferroalloy operations.

- The TSD indicates that the EPA bases its proposed 0.15 lb/ton limit on "potential use of low-NO_X burners and selective catalytic reduction." TSD at 43. EAFs used in ferroalloy manufacturing do not use any on-site combustion, however; instead, the

> required electricity is supplied from the local power company. Accordingly, low-NO_X burners are not a viable option for the ferroalloy industry. In addition, commenter (0345) knows of no SCR system in use anywhere worldwide in the ferroalloy industry.

Commenter (0345) argues if the EPA wishes to regulate open EAFs in the ferroalloy manufacturing industry, it must evaluate that industry, not simply assume that the same controls and emissions levels will be available to all equipment that happens to fall within the same four-digit NAICS code.

Commenter (0287) recommends that the EPA not include ferroalloy EAFs in its definition of EAFs (§ 52.43(a)), based on discussions with Ohio EPA.

Commenter (0345) continues, the analysis of potential controls in the TSD discusses SCR and/or NSCR at annealing furnaces, reheat furnaces, coke oven plants, combustion processes, and cupola melt furnaces; EAFs are not addressed in this discussion. TSD at 32-41. The Menu of Control Measures does not identify EAFs at all, much less identify potential control technologies or assess their cost-effectiveness. (see MCM at 15-16.) Indeed, the Alternative Control Techniques document for the iron and steel industry – the very document that the TSD relies on -- expressly states "There is no information that NO_X emissions controls have been installed on EAF's or that suitable controls are available." ACT at 5-23 (emphasis added). Commenter (0345) identified nowhere in the record where the EPA has identified any available and cost-effective control technology to reduce NO_X emissions from EAFs. And yet the final TSD calls for an emissions limit of 0.15 lb/ton steel on EAFs, based on the use of low-NO_X burners and SCR. TSD at 43.

Commenter (0280) states in the preamble of the proposed rule, the EPA sets forth a rationale for establishing emissions limitations for the Iron and Steel Industry. However, as the proposed rule relates to EAF operations, the EPA's explanation is inaccurate and misleading. The EPA explains that its basis for setting the unachievable emissions limitations is consistent with already promulgated regulatory strategies. Further, the EPA fails to relate the proposed emissions limitations to the control of NO_X emissions from EAF operations. After laboriously reviewing the OTC model rules, no states located in the OTR have promulgated RACT NO_X rules pertaining to EAF operations. In fact, no OTC model rule or recommendation has even been presented for EAF operations. Clearly, the EPA fails to provide established regulatory strategies to reduce NO_X emissions from EAF operations and lacks the technical justification to further control EAF emissions as proposed. Therefore, the EPA must not finalize the proposed rule as it relates to EAF operations.

Commenters (0298, 0514, 0557) state almost all the iron and steel sector facilities linked to downwind monitors are integrated steel facilities that produce steel from iron ore using blast and BOFs. This facility type is significantly different from EAF steelmaking facilities, which produce steel from scrap metal using electrical energy. EAF steel producers and integrated iron and steel facilities have completely different processes, characteristics, equipment, emissions profiles, CAA regulations, and feasible control strategies for much of their production of molten steel. Only two EAF steel facilities contribute very small levels of additional ozone at a small quantity of downwind monitors. The EPA should recognize that these facility types are different and must be assessed individually. Given that NO_X emissions and downwind contributions from EAF steel producers are de minimis, this facility type should be excluded from the Rule.

Commenter (0298) adds the EPA acknowledges that the "number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the universe of non- EGU sources, makes it challenging to define a single method to identify appropriate control technologies, measures, or strategies and resulting impactful emissions reductions." Id. at 20082. Yet the proposed rule fails to recognize the heterogeneity that exists among EAFs within the Iron and Steel Mills and Ferroalloy Manufacturing industry group the EPA proposes to regulate. Not all EAFs are identical, and the open, smelting EAFs used by the ferroalloy industry are distinct from the melting and scrap recycling furnaces utilized in the steel and related industries to melt scrap and manufacture steel alloys.

Commenters (0298, 0514) explain, ferroalloy facilities smelt raw materials in open, submerged, EAFs to produce silicon metal, ferrosilicon or ferromanganese. The furnaces operate on a continuous basis. The submerged electric arc process is a reduction smelting operation in which metal oxides from raw materials are reduced to base metal. An alternating current applied to carbon electrodes causes current to flow through the charge between the electrode tips. This provides a reaction zone at temperatures up to 2,000℃ (3,632℉). At high temperatures in the reaction zone, the carbon sources react with metal oxides to form CO and to reduce the ores to base metal. Electrical resistance is provided by the slag and furnace charge. The submerged electrodes often produce furnace cavities, or blows, during which time excessive heat and gases are produced. Gases formed during the silica reduction process in the reaction zone are emitted at the top of the furnace and are oxidized in an area between the furnace top and capture hood. The heat release from combustion generates "thermal" NO_X at the top of the furnace (before capture by the furnace hoods), as nitrogen in the air reacts with available oxygen in the combustion zone above the furnace to form NO_X. EAFs used for silicon production exhibit NO_X concentrations between 10 ppm and 200 ppm, with emissions factors up to or exceeding 65 lb NO_X/ton of metal, depending on the specific ferroalloy. It is worth noting, metal production rates in primary ferroalloy furnaces are generally less than 30 tons per hour. The furnace is tapped by opening a tap hole that routinely produces a blowing tap, wherein tremendous heat and gas is produced. Such transient conditions lead to extreme fluctuations in process gas flow rates and pollutant (specifically NO_X) concentrations in the process gas.

Commenter (0298) continues, by contrast, an EAF used for steel production (an EAF is not typically used to produce iron) essentially operates as a melting furnace. These EAFs are not referred to as producers of primary metals (as compared to primary ferroalloy production facilities) and instead are referred to as producers of secondary metals because the main metal charge consists of scrap steel and iron. Such EAFs operate to produce secondary steel products and are predominantly found in steel mini mills, although some are also operated in integrated steel mills. Scrap metal and other ingredients used in the melting process are charged to the EAF in batches. During charging, the retractable roof of the EAF is moved away from the furnace shell to allow a charging bucket access to the EAF through the open top of the furnace. After charging, the roof is repositioned over the furnace shell, and the entire furnace chamber is enclosed, allowing the process gases to be easily collected and delivered to an air pollutant control system. In a secondary metal EAF, the electrodes are lowered to a point above the charge material and energized. The arc generated when the electrodes are energized provides the heat needed to melt the charge, and the atmosphere above the arc provides the electrical resistance. Slag formed during the melting process floats on the molten metal in the furnace, providing a thermal blanket to preserve heat in the furnace and also provide arc stability. Tapping occurs by tipping the furnace and pouring the molten metal into a ladle. Alloys also can be added to the ladle when producing ferroalloys. The EPA RBLC reports NO_X emissions factors from steel-producing EAFs (primarily mini mills) between 0.13 and 1.43 lb/ton. The RBLC reports EAF metal production rates ranging between 45 tons of steel per hour and 505 tons steel per hour.

Commenter (0298) concludes, ferroalloy EAFs by design produce thermal NO_X under conditions that are significantly more difficult to control and at greater concentrations than EAFs used in secondary metal production in the steel industry. Not all EAFs are the same, and the EPA's proposal to regulate EAFs as such arbitrarily ignores the unique conditions presented to the control of NO_X at ferroalloy EAFs.

Commenter (0514) states the EPA has consistently distinguished between SAFs and EAFs. When promulgating the very first NSPS, the EPA issued different standards for EAFs (subpart AA) and SAFs (subpart Z). These standards also acknowledged (and continue to acknowledge) different emissions limits applicable to EAFs and SAFs, and different opacity limits applicable to a meltshop that supports an EAF versus a meltshop that supports an SAF. Likewise, when EPA first published its list of source categories under section 112 of the CAA, the EPA found "Ferroalloys Production," "Integrated Iron and Steel Manufacturing," "Non-Stainless Steel Manufacturing—Electric Arc Furnace (EAF) Operation" and "Stainless Steel Manufacturing—Electric Arc Furnace (EAF) Operation" to constitute different source categories. The EPA subsequently published independent NESHAP standards for Ferroalloys Production, Integrated Iron and Steel, and Electric Arc Furnace Steelmaking Facilities. And as with the NSPS, these NESHAP set different performance standards for SAFs and EAFs.

Commenter (0266) states in some cases the emissions limits are in pounds per tons of steel and other times in pounds per mmBtu. The proposed definitions for the emissions unit types also often refer to "steel" as the product. Is it the EPA's intent for these emissions limitations to not apply to ferroalloy manufacturing?

Commenter (0504) strongly urges the EPA to reconsider its inclusion of the iron and steel sector in the proposed FIP. Iron and steel sector NO_X emissions, much less those from the EAF steel producers that are a distinct subset of the sector, do not contribute significantly to downwind nonattainment or interfere with maintenance. The EPA therefore has no obligation – or authority - under the CAA to impose unrealistic, unproven, and costly controls on the iron and steel sector, and particularly EAF steel producers, to facilitate attainment with the 2015 Ozone NAAQS. To the contrary, the arbitrary and capricious imposition of unsupported and unattainable emissions limits on EAF steel producers will only serve to undermine the validity and legal defensibility of the proposed FIP.

Commenters (0287, 0336, 0405, 0504) recognize that the phrase "that directly emits or has the PTE 100 tpy or more of NO_X," describes the emissions units that would be subject to the proposed FIP, and not the “iron and steel mill or ferroalloy manufacturing facility.” Thus, an individual emissions unit at an EAF steel mill could become subject to the proposed FIP’s limits if it had a PTE of 100 tpy or more of NO_X, but the overall EAF steel mill (and all relevant emissions units therein) would not become subject to the proposed FIP if the aggregated PTE of all of its emissions units exceeded 100 tpy. This interpretation of proposed Section 42.43(b) is supported by the contrasting approach to applicability proposed for “each BOF shop” as well as explanations in the preamble to the proposed FIP and within the administrative record.

Commenter (0523) states that there are a number of ambiguities with the emissions limits proposed for coke ovens charging and coking and for pushing if they were applied to a non-recovery plant. It is not clear whether the 0.6 lbs/ton charging limit would apply to the flue gas stream from the coke ovens as indicated by the reference to “coke ovens” and “coking,” or whether it would apply to the PCM, given the reference to “charging,” or both. The commenter adds that the pushing emissions limit is problematic as it references “lb/ton of coal pushed” and only coke is pushed from the ovens, not coal, and the quantity of coal charged into ovens is different from the quantity of coke pushed out. The commenter remarks that it is also unclear whether any hypothetical charging emissions limit or pushing emissions limit would be from the stack of the PCM or hot car, respectively, or whether these limits would somehow apply to fugitive emissions from the coke ovens during such operations, given the reference in both cases to “coke ovens.” The commenter adds that it appears that the EPA intends to regulate charging operations with the 0.15 lb/ton limit, however, the commenter has not found any evidence that this referenced AP-42 emissions factor exists that the EPA cites associated with limit. The commenter adds that there is no AP-42 emissions factor for NO_X from non-recovery charging operations because the NO_X emissions are negligible. Also regarding this limit, the commenter notes that it is for “coal pushed” from “Coke Oven push cars and pushing-charging machines (pushing),” and the commenter states that the reference to “push cars” and “pushing charging machines” in the context of pushing emissions is confusing for non-recovery facilities. The commenter’s plants push coke into regular “hot cars” or “flat push hot cars” and do not have “push cars.” Additionally, the commenter states that there are no emissions from the PCM stack during pushing operations, and the reference to “pushing charging machines” for the proposed pushing emissions limit stands in contrast to the absence of any reference to the PCM for the proposed charging emissions limit of 0.15 lb/ton of coal. The commenter opines that the Agency may have had something unrelated to the PCM in mind in proposing the 0.15 lbs/ton charging limit.

Commenter (0523) believes the EPA did not intend to regulate non-recovery/heat-recovery coke plants, based on the absence of any analysis of such plants in the development of the proposed rule. However, the commenter states that clarification is necessary given the absence of a clear exemption, the reference to “pushing charging machines,” which are unique to the commenter’s operations, and a reference in the preamble to a SunCoke facility as the basis for a pushing emissions limit at coke plants. Accordingly, the commenter requests that the Agency provide a clear exemption for non-recovery and heat-recovery coke plants in the final rule.

Commenter (0798) states that it is unclear how the EPA’s modeling incorporates NO_X reductions that would be achieved through the NO_X emissions limits. For example:

- In the pre-FIP model, what inputs did EPA consider from coke plants?
- How were these sources of NO_X emissions shown to contribute or interfere with ozone nonattainment in downwind receptors?
- How did EPA show that the proposed controls for these units would result in any measurable improvement in ozone concentrations monitored at downwind nonattainment receptors?

Commenter (0523) states that because the EPA failed to consider emissions reductions and costs resulting from the regulation of non-recovery/heat-recovery coke plants, the Agency cannot regulate those emissions after the fact. The commenter states that there is no evidence in the record that the EPA modeled the emissions contributions of non-recovery/heat-recovery coke plants to determine whether they were significant, or whether installation of additional control technology would be feasible or cost effective. The commenter asserts that this lack of analysis fails to comply with EME Homer City's requirements for controlling upwind sources. The commenter further asserts that SCR and SNCR would be unprecedented, infeasible, and cost prohibitive at non-recovery/heat-recovery coke plants. According to the commenter, due to these factors, if its facilities were included in any final rule, it would exceed the EPA's statutory authority.

Commenter (0523) remarks that the EPA recognizes that not all non-EGU sources in the targeted segments will be able to achieve compliance with the standards and notes that in past CSAPR rules, the EPA has handled the issue of feasibility through an allowance trading program. However, the commenter points out that there is no trading program for non-EGUs in the proposed rule where compliance is not cost-effective. The commenter asserts that if the EPA desires to promulgate standards that apply to each source in an industrial segment, the standard articulated in EME Homer City requires it to, at minimum, provide a safety value for sources for which installation of controls is not cost-effective.

Commenter (0798) notes that according to the Proposed Non-EGU Sectors TSD, the EPA's proposal assumes a projected reduction efficiency of 40-50 percent based on current permit emissions limits and production-based push/charge cycles; and that the EPA projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X practices, staged pushing and hood configurations, and potential use of add-on NO_X control technology at larry cars and pushing/charging machines. According to the commenter the EPA also acknowledges that, "coke ovens with NO_X controls in the United States have not been found," yet, the EPA is proposing sweeping NO_X controls across coke plants in the U.S. The commenter continues by stating that the overall NO_X emissions from charging and pushing are minimal, any emissions control equipment installed would result in minimal NO_X reductions, the application of SCR technology is not technically or economically feasible and would substantially increase other pollutants. The commenter notes that work produced by Trinity Consultants shows that the minimum cost effectiveness for the potential application of SCR at the Clairton C Battery coke pushing after the baghouse would be $271,472/ton (2021$), with 72 tons of NO_X formed from combustion of natural gas to reheat the exhaust gas steam compared to approximately 92 tons from the unit itself, as well as approximately 87,000 tpy of CO2. The commenter states that these numbers clearly show how the application of SCR to coke ovens is not a cost-effective approach and should not be required.

Commenter (0523) states that a FIP addressing interstate transport of pollutants must also involve an appropriate degree of control, including sufficient controls to address the state's contribution to downwind nonattainment, but no more control than is necessary to meet that requirement.

Commenter (0523) argues the EPA's one-size-fits-all approach to the non-EGU provisions of the proposed rule presents significant questions whether it exceeds the Agency's authority under the good neighbor provision of the CAA. Furthermore, in addition to cost-effectiveness and over-control issues, even in the context of a FIP, the EPA likely does not have authority to impose such specific control measures on a state. (see Virginia v. EPA, 108 F.3d 1397, 1408 (D.C. Cir. 1997)). Regulation of several industries across a region is fundamentally more complex than establishing a region-wide emissions trading program for a single industry. With a trading program, such as the CSAPR, it is comparatively easy to confirm that the reductions required by an individual state are proportionate to its contribution to downwind nonattainment. It is far more challenging to impose region-wide emissions control requirements across a number of different industries while ensuring that each state bears its fair share – and only its fair share – of the burden. The proposed rule effectively establishes a suite of region-wide obligations, regardless of (a) any individual state's contribution to nonattainment, (b) the presence of identified non-EGU source categories within that state, or (c) the degree to which the selected targets of the rule will result in a degree of control within each state that is proportional to that state's contribution to downwind nonattainment. The EPA calculates the emissions reductions projected to result from the proposed rule in each state in its Regulatory Impact Analysis, as well as the change in ozone levels at various downwind receptors projected to result from the rule. However, it is not clear that the EPA specifically establishes that the emissions reductions in each upwind state resulting from the proposed rule's combined EGU and non-EGU measures are the minimum amount necessary to achieve attainment at each downwind receptor to which the upwind state is linked. (see generally Regulatory Impact Analysis, appx. 3B; see also EPA, Ozone Transport Policy Analysis Proposed Rule TSD (Feb. 2022)).

Commenter (0523) believes if the proposed rule were to regulate SunCoke as a mere afterthought, it would necessarily result in over-control. The EPA is required to strike a careful balance to ensure that it eliminates significant contribution to nonattainment while avoiding over-control. The rule asserts that "EPA's over-control analysis . . . shows that the proposed control stringencies for EGU and non-EGU sources do not overcontrol 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[.]" 87 Fed. Reg. at 20043-44. If the Agency neglects to study the proposed emissions reductions from a particular industry, but then anyway regulates that industry—or even one facility within that industry—it would upset this careful balance and result in more emissions reductions than calculated. As a result, the FIP would exceed EPA's authority in every state where such facilities are located for overcontrolling emissions from those states. See North Carolina v. E.P.A., 531 F.3d 896, 929–30 (D.C. Cir. 2008) ("EPA's approach—regionwide caps with no state-specific quantitative contribution determinations or emissions requirements—is fundamentally flawed... The trading program is unlawful, because it does not connect states' emissions reductions to any measure of their own significant contributions.").

Commenter (0523) goes further, this is precisely what would happen if the proposed rule were finalized to regulate non-recovery/heat-recovery coke plants, or if the EPA failed to clarify that nonrecovery/heat-recovery coke ovens are excluded. There is no evidence in the proposed rule's underlying spreadsheets, the Regulatory Impact Analysis, or the screening assessment that the EPA accounted for current emissions estimates, proposed emissions reductions, or cost estimates for additional NO_X controls at non-recovery/heat-recovery coke oven batteries. If the EPA were to regulate additional sources such as non-recovery/heat recovery coke ovens after the fact, it would upset the careful balance the EPA must strike between addressing significant contribution from upwind states without over-controlling those emissions. It would also be arbitrary and capricious because the rule would "rel[y] on factors which Congress has not intended it to consider," namely unnecessary over-attainment in downwind states. See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983). Commenter (0523) again respectfully urge the EPA to clarify in the final rule's regulatory text that non-recovery/heat recovery coke plants are not subject to this program. This would eliminate any ambiguity and avoid finalizing a rule that is arbitrary and capricious and exceeds EPA's statutory authority.

Commenter (0523) argues it is unnecessary to regulate nonrecovery/heat-recovery coke plants beyond their existing permit limits for NO_X. The concentrations of NO_X in the flue gas stream from commenter's (0523) coke plants are less than 5 percent of the NO_X levels at a traditional byproduct coke oven battery. Even with new controls that have a 90 percent removal efficiency, a very aggressive assumption, most byproduct coke oven batteries would fail to achieve SunCoke's current NO_X concentrations. It is particularly unnecessary to regulate NO_X from pushing and charging operations at our plants, which appear to be the primary intent of the ambiguous emissions limits described in Section II.A of the proposed rule, given the fact that little to no combustion occurs in these processes. Charging is a negligible source of NO_X with no AP-42 emissions factor for non-recovery coke plants, while pushing emits less than 10 ppm NO_X at our plants. Commenter (0523) is not aware of any feasible technology to reduce NO_X levels below current permitted limits at our non-recovery/heat-recovery coke plants.

Commenter (0523) continues, were the EPA to go further and finalize a rule that applies to SunCoke's facilities, it likely would run afoul of the requirements for notice-and-comment rulemaking. In order for an agency to provide adequate notice and opportunity to comment, the final rule must be a "logical outgrowth" of the proposal. Small Refiner Lead Phase-Down Task Force v. EPA, 705 F.2d 506, 547 (D.C. Cir. 1983). The "notice must describe the range of alternatives being considered with reasonable specificity" such that interested parties will "know what to comment on" and the Agency's decision making can be "better-informed." "[V]ague and conflicting signals" are insufficient to provide reasonable notice. Michigan v. EPA, 213 F.3d 663, 692 (D.C. Cir. 2000). Here, the EPA has made, at most, some vague references that could indicate it intends to regulate non-recovery/heat-recovery coke plants, but those references are insufficient to alert interested parties that they should comment on the full range of questions involved in regulating such facilities.

Commenter (0758) disagrees, showing their support for more stringent standards for coke ovens with the application of pollution controls.

Commenter (0523) states the proposed rule's background documents cite control measures other than SCR to minimize NO_X emissions from coke plants. All of these measures are inherent to commenter's (0523) non-recovery/heat-recovery process to the extent they are relevant. The TSD cites an EU report identifying flame temperature reduction, waste gas recirculation, and staged air combustion as being among the most effective ways of reducing NO_X formation. See TSD at 35. The aforementioned Japan Iron and Steel Federation report similarly identifies low-air-ratio combustion and flue gas recirculation as NO_X control techniques for coke ovens.

Commenter (0523) adds three-stage air combustion and controlling peak flame temperatures are inherent to the non-recovery cokemaking process. Similarly, flue gas recirculation is inherent to non-recovery/heat-recovery coke plants through (1) the oven's internal gas distribution systems utilizing the downcomers to direct gas from the crown to the sole flues; (2) the uptakes then directing the gas to the common tunnel which stages the burn of the flue gas with differing oxygen levels; and (3) the final mingling of flue gas in the common tunnel with different levels of oxygen from different ovens at different stages of the coking cycle.

Commenter (0523) states the only coke plant controls cited in the TSD that are not and cannot be implemented at a non-recovery/heat-recovery coke plant are (a) SCR and (b) using thinner bricks in the oven heating chamber. A non-recovery coke plant also cannot make "structural changes . . . to the heating chamber to improve thermal conductivity, such as using thinner bricks." There is no distinct heating chamber in a non-recovery coke oven. The entire purpose of using thinner bricks at byproduct coke ovens with heating chambers is to "decreas[e] the temperature gradient over the refractory brick wall from the heating chamber side to the coke oven chamber side," and "can only be applied in new plants." (see Rainer Remus, et al., Joint Research Centre of the European Commission, Best Available Techniques (BAT) Reference Document for Iron and Steel Production, Industrial Emissions Directive 2010/75/EU (2013), at 257-58.) In addition, thinner bricks would increase the likelihood of oven wall and floor cracks (or even collapse) that would compromise the ovens' negative pressure design—negating the qualities that make non-recovery cokemaking preferred by the Agency under the MACT standard.

Commenter (0523) states when installed at coal-fired boilers, SCRs have mainly been applied to electric utilities and large industrial boilers ranging in size from 1,300 to 8,000 MMBtu/hour. In these applications, SCRs are usually installed between the economizer and air heater because boiler outlet temperatures are usually much cooler than 700°F. This ensures that the gases entering the SCR reactor are in the appropriate temperature range. An economizer bypass can be used to divert part of the hot flue gas around the economizer to bring the temperature into the optimum range. The temperature of the gas stream is cooled in the air heater, downstream of the SCR reactor, to the desired outlet temperature.

Commenter (0523) explains, in contrast to a typical coal-fired boiler at an electric utility, no combustion takes place in the heat recovery steam generators at SunCoke's heat recovery coke plants. The HRSGs are also fairly simple and compact, consisting of only three sections: a superheater, evaporator, and economizer. The economizer in these HRSGs is designed to cool the flue gases to 350-400°F, compared to the typical large boiler or heater with economizer outlet temperatures closer to the 650–750°F range. At 350-400°F, the gas temperature is outside the range where SCR is effective. SunCoke's HRSGs are also relatively small units in size and duty (100 MMBtu/hour), designed to produce steam from waste heat. Unlike utility boilers, they do not contain sections within the unit where the temperature is in the effective range of SCR. Another problem with the use of SCR at a heat recovery coke oven battery is the unique flue gas containing inherently fouling ash, in contrast to the light fly ash of a coalfired boiler. The particulate loading in heat-recovery coke oven flue gas is low due to the inherently excellent combustion, but with little alkaline fly ash to adsorb HCl, sulfates and chloride salts form in air pollution control devices, including but not limited to sodium, ammonium, and potassium salts. Coal fly ash at a utility boiler is light and remains suspended, whereas these sulfate and chloride salts are sticky and easily form deposits.

Commenter's (0523) heat recovery coke ovens must be operated to minimize deposition of sulfate and chloride salts. Despite installation of special soot blowers to address this issue, regular maintenance of the HRSGs is necessary to remove the deposits of material and prevent corrosion and plugging of these systems. During these maintenance periods, the flue gas generally must be routed to vent stacks that bypass the HRSGs and FGD because coke ovens cannot be shut down without causing catastrophic damage to the ovens. As a result, proper operation and maintenance of the system to limit the deposition of sulfate and chloride salts and periodically remove such deposits is critical to minimize HRSG and FGD downtime and resulting emissions. This is not the case with utility boilers, which are routinely shut down if problems develop in the air pollution control system. Given these unique flue gas characteristics, if SCR were applied to a heat recovery coke oven battery, the ash would plug or poison (*i.e.,* deactivate) the SCR catalyst. Moreover, using SCR would result in the formation of ammonium sulfates and bisulfates that would cause plugging of downstream equipment and would result in additional fouling. See J. Menasha et al., Ammonium Bisulfate Formation Temperature in a Bench-Scale Single-Channel Air Preheater, 90 Fuel 2445 (July 2011). This would result in the need for even more cleaning and HRSG maintenance, which would increase emissions because of additional time that the FGD system would be bypassed.

Commenter (0523) states in addition to more HRSG maintenance and downtime, the increased deposits and plugging of downstream equipment would increase pressure drop across the system, which would adversely impact the negative pressure design of the ovens. If the ovens were not operating under negative pressure, HAPs may be emitted to the atmosphere instead of being combusted, as is the case at byproduct coke plants operating under positive pressure. This would also adversely impact the staged combustion process, temperature control, and flue gas recirculation within the oven system, which could result in more NO_X formation within the ovens and, theoretically, fugitive NO_X being emitted from leaking ovens. In other words, the pressure drop added by the SCR as well as increased fouling problems resulting from SCR likely would defeat the purpose of installing SCR in the first place. There would also be a safety issue if ovens began to operate under positive pressure, as flames would emerge from dampers and other openings that are intended to introduce air into the system. As a result, retrofitting SCR at a heat recovery coke plant would further require increased power for the induced draft fans, as well as a revamp of the existing FGD system to handle the higher draft requirements.

Commenter (0523) continues, the low NO_X concentrations in the flue gas at a non-recovery coke plant present another significant hurdle for SCR to achieve cost-effective NO_X removal. For SCR, "higher uncontrolled NO_X inlet concentrations result in higher NO_X removal efficiencies due to reaction kinetics[,]" whereas "[l]ow NO_X inlet levels result in decreased NO_X removal efficiencies because the reaction rates are slower, particularly in the last layer of catalyst." (see EPA, EPA Air Pollution Cost Control Manual (EPA/452/B-02-001), at Sec. 4.2, Ch. 2, 2-13 (6th ed. 2002)). As a result, even if installing SCR were technically feasible, commenter (0523) would expect very low removal efficiency at a non-recovery coke plant.

Commenter (0523) concludes SCR is not feasible at a non-recovery/heat-recovery coke plant. It is impossible to quantify the hypothetical cost of a system that is not technically feasible, particularly in the limited period of time for submitting these comments. However, if the costs of such a system were quantified without regard for infeasibility, commenter (0523) is confident it would substantially exceed $7,500 per ton NO_X removed, even for a new coke plant. Under the proposed rule, the EPA's analytical framework of nonEGU sources that would be subject to control requirements was subject to a marginal cost threshold of up to $7,500 per ton. See 87 Fed. Reg. at 20083; Regulatory Impact Analysis at 4-9. The costs would be even higher for a retrofit design due to the pressure drop issues identified and redesign of the FGD. In sum, SCR has never been applied to the heat recovery cokemaking process because of the absence of a zone with appropriate temperatures to install SCR in these relatively small and simple HRSGs, as well as the increased likelihood of HRSG fouling that would result in more overall emissions. It is not technically or economically feasible.

Commenter (0523) states SNCR is similarly infeasible at a non-recovery coke plant and has never been used with this process. SNCR is a post-combustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or connective pass of a boiler. The ammonia or urea reacts with NO_X in the gas to produce nitrogen and water. Multiple injection locations are required within several different zones of the boiler to respond to variations in the boiler operating conditions. The effectiveness of SNCR depends on the temperature where reagents are injected, mixing of the reagent in the gas, residence time of the reagent within the required temperature window, ratio of reagent to NO_X, and the presence of sulfur compounds in the flue gases (ammonia reacts with SO_2 and SO3 to form ammonium sulfates and bisulfates). As with SCR, there is an increased likelihood for HRSG fouling with SNCR, which would increase overall emissions, and there is no appropriate injection location at a non-recovery coke plant.

Commenter (0523) continues, heat recovery coke oven flue gas does not contain the light coal fly ash of a coal-fired boiler. The particulate material in the heat recovery flue gas is acidic and contains sulfates and chloride salts, including but not limited to sodium, ammonium, and potassium salts, with a demonstrated tendency to cause fouling. One problem with SNCR at a heat recovery coke plant is the formation of ammonium sulfates and bisulfates that cause additional fouling and would result in plugging of downstream equipment. For SCR, this would lead to a need for even more HRSG cleaning and maintenance, which would increase emissions because of additional time that the FGD is bypassed. In addition, it would increase pressure drop throughout the system, which could result in an overall increase in both NO_X and HAPs by compromising the negative pressure design of the ovens. In a retrofit application, this likely would require a redesign of the FGD and increased power consumption by the induced draft fans.

Commenter (0523) continues, the second major obstacle to the use of SNCR at a non-recovery plant is the need for a specific temperature range and residence time. The required temperature window is 1,600–2,200°F, with the most effective range being 1,800–2,100°F. Above these temperatures, more NO_X will be formed from nitrogen in the reagent, while no reaction will occur below these temperatures. At a non-recovery coke plant, the oven crown and sole flue would not be appropriate locations to add ammonia or urea because the temperatures are generally higher than this range. The temperature in the common tunnel and hot duct to the HRSG varies from 1,800°F to 2,400°F each day and is permitted to drop down as low as 1200°F to 1400°F, depending on the plant. The continuous batch nature of the nonrecovery/heat-recovery coking process results in fluctuations in the flue gas flow rate, composition, and temperature from 15-20 percent below average to 15-20 percent above average, which results in a very broad operating range. Therefore, any hypothetical SNCR system for heat recovery coke ovens would have to be instrumented with a system that could monitor the changing temperatures throughout the 2,000 ft of common tunnel and hot ductwork for the HRSGs, with many injection locations so that reagent could be injected where needed, which has never been proven to be feasible. This contrasts with an SNCR application at a boiler where the injection locations would be close together and temperatures in those locations are more uniform.

Commenter (0523) states a third significant obstacle for SNCR is that even with multiple injection points in the correct locations, a hypothetical SNCR system would achieve a very low removal efficiency due to inherently low NO_X concentrations well below 100 ppm. (see EPA, EPA Air Pollution Cost Control Manual (EPA/452/B-02-001), at Sec. 4.2, Ch. 1, 1-10 (Figure 1.5) (6th ed. 2002) (demonstrating that for a 70 ppm initial NO_X level, less than 25 percent reduction is expected at 2000°F); G. Quartucy et al., The Effect of Initial NO_X Levels on Selective Non-Catalytic NO_X Reduction Performance, Am. Chem. Soc'y, Div. Flue Chem. 38 (2), 699-707 (1993).

Commenter (0523) concludes, besides the fact that SNCR has never been demonstrated at a nonrecovery/heat-recovery coke plant, it is well-established that it is not feasible to achieve a reasonable removal efficiency at such low concentrations of NO_X. As is the case with SCR, it is not possible to quantify the hypothetical cost of a SNCR system that is not technically feasible, particularly in the limited period of time for submitting these comments. However, if the costs of such a system were quantified without regard for infeasibility, SunCoke is confident it would substantially exceed $7,500 per ton NO_X removed even for a new coke plant, above the EPA's marginal cost threshold for non-EGU sources. See 87 Fed. Reg. at 20083; Regulatory Impact Analysis at 4-9. The costs would be even higher for a retrofit design. SNCR is not technically or economically feasible for non-recovery/heat-recovery coke plants.

Commenter (0523) has also evaluated the hypothetical installation of a "tail-end" SCR system ("TESCR") located after the FGD for heat-recovery plants. Even if designed for a new plant, there are several issues that make such a system infeasible. TESCR would still cause equipment corrosion and fouling problems from chloride salts and ammonium sulfate and bisulfate formation. This would result in the same pressure drop and negative pressure problems described above for a standard SCR or SNCR system. Additionally, because of the low NO_X concentrations in the flue gas, the removal efficiency of a TESCR system would be extremely low.

Commenter (0523) states temperature presents an even greater challenge in this case compared with a typical SCR installation. The low temperatures at the end of a typical heat-recovery coke plant main stack range from 150-235°F, which would require reheating the gas stream. Reheating the gas stream would result in additional power consumption and associated costs and emissions. For a new heat-recovery coke plant, commenter (0523) estimates that a hypothetical TESCR system would result in increased emissions of greenhouse gases (21,068 tpy CO2), sulfuric acid mist (13 tpy), and ammonia (50 tpy), and would consume significantly more energy (239,525 MMBtu/yr) due to reheat requirements and pressure drop across the unit. These issues would be exponentially greater for a tail-end SNCR system given the substantially higher temperature at which it must operate.

Commenter (0523) concludes a TESCR system even at a new heat-recovery plant is not technically feasible for many of the same reasons a more typical SCR or SNCR design is not feasible. Again, it is not possible to quantify the hypothetical cost of a system that is not technically feasible, particularly during the short comment period for the proposed rule. However, if the costs of such a system were quantified without regard for infeasibility, it would substantially exceed $7,500 per ton NO_X removed for a new coke plant. Under the proposed rule, the EPA's analytical framework of non-EGU sources that would be subject to control requirements was subject to a marginal cost threshold of up to $7,500 per ton. See 87 Fed. Reg. at 20083; Regulatory Impact Analysis at 4-9. The costs and technical problems would be exacerbated for a retrofit application. In sum, there are no feasible post-combustion controls for non-recovery/heat-recovery cokemaking technology, nor are any such controls necessary given the extremely low levels of NO_X.

Commenter (0523) states charging is a negligible source of NO_X at a non-recovery plant as evidenced by the complete absence of an AP-42 emissions factor for non-recovery plant charging operations. No combustion takes place in a PCM. NO_X concentrations in pushing emissions are also extremely dilute at less than 10 ppm and intermittent. The transformation to coke is complete by this stage, ovens must be inspected before pushing to ensure there is no smoke in the oven space above the coke bed, and the coke loaf is pushed essentially intact, limiting the opportunity for additional flames or combustion. Because of these non-existent to minimal NO_X emissions, SCR and SNCR would not be effective. SNCR is of limited effectiveness at NO_X concentrations below 100 ppm, and the effectiveness is even more limited at concentrations below 30 ppm. (demonstrating that for a 30 ppm initial NO_X level, the control efficiency CE ranges from approximately 20 percent to zero percent between 1600°F and 1950°F). Accordingly, neither SCR nor SNCR would meaningfully reduce NO_X emissions from commenter's (0523) pushing or charging operations.

Commenter (0523) adds, the operating temperature issues commenter (0523) describes above for SCR and SNCR would be substantially more problematic at the PCM and hot car. SCR must operate between 500–800°F, with an optimum temperature range between 700–750°F. For SNCR, the required temperature window is 1,600–2,200°F, with the most effective range between 1,800–2,100°F. However, the PCM baghouse stack normal operating temperature is approximately 150°F or less, well below these temperatures. In fact, the PCMs contain an automatic cooling system that cools the gas directed to the baghouse with air as temperatures approach 180-200 degrees, and in emergency conditions cool the gas with water if temperatures approach 250 degrees. This is necessary to prevent the PCM baghouse from burning bags or catching fire.

Commenter (0523) continues, the hot car temperature range is from 300-400°F, which is still 300 degrees below the optimum temperature range for SCR. Reheating the stack gas for the sole purpose of bringing it into the effective operating range would not be effective either for many of the same reasons described in Section IV.C.3 for tail-end SCR, along with additional issues unique to these units. Reheating the air would risk burning the PCM baghouse, and the stack for the hot car cannot be lengthened for a reheating system to remain sufficiently low to pass under stationary equipment. One of the biggest hurdles to any additional control device applied to a mobile piece of machinery at a SunCoke plant is limitations to power supply. Our PCMs and hot cars also already tax the existing rail systems, and adding further weight for controls would push the cost envelope even higher and raise additional feasibility problems.

Commenter (0523) continues, the Regulatory Impact Analysis also did not account for non-recovery/heat-recovery coke oven batteries in tables showing the industries, number and type of emissions units expected to install controls, and the total estimated emissions reductions based on the screening assessment. (see ES-13 (Table ES-5) and 4-45 (Table 4-18)). Nonrecovery/heat-recovery coke oven batteries could not have been included in the Iron and Steel Mills and Ferroalloy category within the 25 “boilers” figure or the 15 “industrial” units figure. Based on commenter’s (0523) knowledge of its own operations, the rest of the cokemaking industry, and the steel industry, neither of these figures could possibly account for non-recovery/heat-recovery coke oven batteries in the relevant states.

Commenter (0523) continues, the screening assessment itself provides additional evidence that nonrecovery/heat-recovery coke oven batteries are not intended to be covered by the proposed rule. The only reference to coke ovens in the screening assessment appears to be under the Emissions Source Group “Industrial Processes - General; Industrial Processes – Coke Oven or Blast Furnace,” identifying only one such unit with its ozone season emissions reductions and annual total cost. See EPA, Technical Memorandum, Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 (Feb. 2022) (“Screening Assessment”), at 17. Commenter (523) has more than one non-recovery/heat-recovery coke oven battery in the states covered by the proposed rule. Moreover, the controls assessed for this one unit are flue gas recirculation and low NO_X burners, which are irrelevant because SunCoke’s coke ovens do not require burners. Finally, none of SunCoke’s facilities appear in the EPA’s screening assessment spreadsheet entitled “Transport Proposal - Screening Assessment Non-EGU Facility and Emissions Unit Lists - 03-18-2022” (Regulations.gov, Document ID EPA-HQ-OAR-2021-0668-0191), the Agency’s “list of facilities in 23 states that the EPA evaluated in the Technical Memorandum: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,” which “generally includes 250 facilities that have 489 emissions units with greater than 100 tpy NO_X emissions.” See also Screening Assessment at 8 (“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.”).

Commenter (0523) adds the emissions limits are ambiguous, the fact that the proposed rule would provide insufficient time to comply if applied to non-recovery/heat-recovery coke plants, the fact that the proposed rule assumes use of technology that is not cost-effective or feasible for such coke plants, and the fact that NO_X emissions are already extremely well-controlled at these facilities. Indeed, the EPA intentionally excluded a number of well-controlled sources like SunCoke’s facilities, and instead focused on uncontrolled sources or sources that could be better controlled at a reasonable cost to ensure emissions reductions are achievable and would lead to air quality improvements. See 87 Fed. Reg. at 20083; Regulatory Impact Analysis at 4-24; Screening Assessment at 3. Commenter (0523) requests that the EPA clarify this fact by providing a clear exemption for non-recovery/heat recovery coke plants in the final rule.

Response:

As explained in more detail in Section VI.C of the preamble, the EPA is finalizing requirements for only reheat furnaces and certain industrial boilers in the Iron and Steel industry and is not finalizing the proposed requirements for blast furnaces, basic oxygen furnaces, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or electric arc furnaces. The EPA has considered the concerns raised by commenters regarding the emissions limits proposed for blast furnaces, basic oxygen furnaces, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces and the technical analysis of information received regarding these units is included in the Final Non-EGU Sectors TSD. To the extent that an integrated iron and steel mill, specialty steel, or ferroalloy facility contains boilers or reheat furnaces subject to this final rule, those sources will need to satisfy the requirements contained in the final rule at 40 CFR §§ 52.43 and 52.45.

5.3.3.2 Applicability Threshold

Comment:

Commenter (0401) presumes the EPA did not intend for iron and steel foundries to be covered by this rule. The EPA specifically identifies NAICS code 3311, Iron and Steel Mills and Ferroalloy Manufacturing, as being covered by this rule. The EPA does not list NAICS code 3315 that includes foundries. While the TSD for the proposed rule does reference units subject to the NESHAP for Iron and Steel Mills and Ferroalloy Manufacturing (40 CFR part 63, subpart FFFFF), and the NESHAP for Iron and Steel Foundries (40 CFR part 63, subpart EEEEE), the EPA does not state that the iron and steel foundry source category is covered by this rule. In addition, the EPA does not provide any data from iron and steel foundry units for NO_X emissions or control cost effectiveness as a basis for establishing the proposed NO_X emissions limits. The data are limited to NO_X emissions from uncontrolled iron and steel mill sources.

Response:

The EPA agrees with commenter's contention that no distinction was made between foundries and other iron and steel manufacturing facilities. In the proposed rule, the EPA identified each emissions unit according to its NAICS code, technical purpose and capability, and PTE NO_X. Foundries that do not operate either reheat furnaces or industrial boilers that meet the applicability criteria in the final rule are not subject to the final rule.

Comment:

Commenter (0416) asks that the EPA remove the definitions for "BOF Baghouse System" and "Steel Production Cycle," noting that neither term is used in the proposed rule.

Response:

These definitions have been removed from the final rule.

Comment:

Commenter (0405) states in the proposed FIP, the EPA proposes to establish enforceable NO_X emissions limitations for more than a dozen listed sources in the Iron and Steel sector. Table VII.C-3 of the preamble to the proposed FIP summarizes the proposed emissions limits along with the EPA's stated basis for the limits. Boilers and Coke Oven limits are inconsistent with limits for the same sources in other parts of the preamble and proposed FIP making it that much more difficult to discern the technical basis for the proposed emissions limits. For example, boiler emissions limits in preamble Table VII.C-3 are inconsistent with the EPA's Table 1 in the proposed FIP [87 FR 20181].

Response:

Although section 52.45(c) of our proposed regulatory text reflected an emissions limit of 0.15 lbs/MMBtu for residual oil-fired boilers, our intent was to propose an emissions limit of 0.20 lbs/MMBtu for this equipment as discussed within the Proposed Non-EGU Sectors TSD and the preamble to our proposed rule. The final rule contains an emissions limit of 0.20 lb/MMBtu for these boilers.

Comment:

Commenter (0416) believes that the applicability section as drafted creates confusion. It references "emissions units" which are undefined. Commenter (0416) suggests that the EPA replace "emissions units" with "affected unit," which is a defined term. And in that regard, commenter (0416) requests that the EPA revise the definition of "affected unit." To provide clarity and ensure consistency across the rule, the definition of "affected unit" should simply state: "any emissions unit identified in Table 1 meeting the applicability criteria of this section."

Response:

The EPA appreciates commenter's suggestion regarding the replacement of the term "emissions units" with "affected unit" and has made that change in the final regulatory text where appropriate.

Comment:

Commenter (0798) asserts that the definition of a reheat furnace as currently drafted is overly vague and should be amended to match the reheat furnaces and related definitions on which the EPA's review was based. The commenter recounts that the current definition of a reheat furnace in the proposed rule is "a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing," but the definition does not define what counts as "steel product." The commenter notes that in setting a limit for reheat furnaces in the proposed rule, the EPA expressly relied on the Ohio RACT limit for reheat furnaces, and Ohio's applicable definition provides that "'Reheat furnace' means a furnace in which metal ingots, billets, slabs, beams, blooms and other similar products are heated to bring them to the temperature required needed for hot-working." The commenter adds that this definition is also consistent with the various permits the EPA looked at when setting a limit for a reheat furnace. The commenter suggests the EPA should likewise clarify its definition of reheat furnace to match the definition used by Ohio or otherwise revise the definition to differentiate more clearly a reheat furnace, which handles pre-made intermediate products, from something like a tunnel furnace that merely maintains and equalizes the temperature of raw already-hot-slabs while in transit from a caster to some other operation like a rolling mill.

Response:

The EPA agrees with commenter's request to clarify the definition of reheat furnace. The final rule defines reheat furnace, consistent with Ohio's regulation, as "a furnace 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."

Comment:

Commenter (0798) states that the EPA should resolve the current discrepancy concerning the basis for the 40 percent reduction the EPA is requiring at reheat furnaces. According to the commenter, the proposed rule states that a 40 percent reduction is assumed based on installation of SCR, whereas the underlying Proposed Non-EGU Sectors TSD states that the 40 percent reduction is instead based on low-NO_X burners, not including SCR. The commenter states that the EPA must provide additional rationale for the reductions, because assuming reductions based solely on the basis of low NO_X burners may be inconsistent with the fact that the permit limits the EPA reviewed in setting this limit already had low-NO_X burners installed, and it may not be reasonable to assume any additional emissions reductions. The commenter adds that if the reductions are based on SCR, then the EPA must detail why it believes SCR is feasible and cost effective for such units.

Response:

Low-NO_X burners are both well-worked technologies that have proven to be effective at reducing NO_X in many different exhaust streams. The Proposed Non-EGU Sectors TSD discussed these and other technologies as likely means to achieving NO_X reductions at emissions units identified in the proposed rule. In some cases, these technologies have been tested on certain iron and steel manufacturing units internationally. Given the available data regarding varying degrees of reduction efficiency achieved at different types of emissions units both international and domestic, compared to stack test and permit data, the EPA determined most units would be able to meet target reduction design specifications between 20 percent and 98 percent reduction efficiency, depending on the unit.

The EPA is basing the requirement to reduce NO_X emissions by 40 percent on the widely available and cost-effective low-NO_X burner technology. However, the owner/operator of a reheat furnace may choose to install and operate other control technologies that achieve equivalent emissions reductions. An updated discussion of the technical basis for this requirement is included in the Final Non-EGU Sectors TSD.

Comment:

Commenter (0308) states a one-size-fits-all type of regulation does not consider individual differences in types, sizes and contributions of industrial sources across the regulated region and eliminates any flexibility or creativity a state may have to develop targeted state and local specific measures to allow a state to better meet its good neighbor obligations.

Response:

In the case of reheat furnaces, the final rule does allow sources to install control technology to meet a 40 percent emissions reductions requirement. The EPA assumes most reheat furnaces will install low-nox burners, but owners and operators have flexibility to install other control technologies that achieve equivalent emissions reductions.

To the extent the commenter is concerned about an individual state's ability to replace the FIP with the SIP, those comments are addressed in Section. VI.D of the preamble.

Comment:

Commenter (0416) asserts that the EPA should raise the applicability threshold to some level higher than 100 tons of NO_X per year PTE to harmonize iron and steel applicability to EGU applicability. Specifically, applicability for EGUs is based on a 25-megawatt generator. Such EGU sources have a PTE closer to 150 tons of NO_X per year. For illustration purposes, a 25MW gas-fired turbine could emit more than 150 tpy of NO_X (assuming the unit operates at an emissions rate of 1.4 lb NO_X per megawatts hour (MWh)). Mathematically, this calculation is as follows:

$$25\ [MWh] \times 1.4\ [lbs\ NO_X/MWh] \times 8760\ [hours/year\ (yr)] / 2000\ [lbs/ton] = 153 \text{ tons of } NO_X \text{ per year.}$$

Thus, the EPA is imposing mandates on emissions units in the iron and steel mill industry that are smaller from an emissions standpoint than EGUs. To ensure that the rule does not unnecessarily impose obligations on smaller sources, and to ensure uniformity across industries, commenter (0416) requests that the EPA set the applicability threshold for iron and steel mill units to at least 150 tons of NO_X per year PTE.

Response:

The basis for EPA's applicability thresholds based on design capacity and PTE for non-EGU industries is addressed in Section VI.C. of the preamble.

Comment:

Commenter (0287) interprets the Docket to mean that aggregation of units is applicable only to BOF shops. This interpretation stems from the clear language previously cited as well as the unreasonableness of requiring controls and Continuous Emissions Monitoring ("CEMS") on multiple, small emissions units that happen to, collectively, emit 100 TPY of NO_X. The high cost of controls and monitoring relative to the relatively low emissions from each unit would be impractical.

Response:

The final rule only applies to boilers with a design capacity of 100 MMBtu/hr or greater and reheat furnaces that individually have a PTE of more than 100 tpy of NOx in the Iron and Steel industry. For a further discussion of the basis for these limits see Section VI.C.3 and VI.C.5 of the preamble.

Comment:

Commenter (0504) notes numerous factors impact the propensity of pollutants, including NO_X, to transport between states and contribute to downwind attainment issues. The most widely-recognized factors in the transportability of NO_X and other pollutants, however, are the height and the velocity that the pollutants are released in the air column. The height that pollutants are released in the air column is also influenced by numerous variables, but is most influenced by the height of the stack from which the pollutants are released, the velocity at which the pollutants are released, and the amount of pollutants emitted from the stack. Each of these factors distinguishes iron and steel industry emissions, and particularly emissions from EAF steel producers, from the more widely transported EGU emissions.

Commenter (0504) points out the vast majority of tall stacks (defined as those exceeding 500 feet) are in use at EGUs. The input files the EPA used to model potential NO_X transport from the iron and steel sector reflects that only a single steel manufacturing facility operates stacks in excess of 250 feet (a U.S. Steel coke plant). To the extent EAF steel producers utilize stacks, those stacks rarely exceed 200 feet and only for certain sources such as reheat furnaces. Further, most EAF steel producers do not emit pollutants through stacks at all from many of their sources. For example, emissions captured from EAFs and/or other emissions units in the meltshop are most often ducted to baghouses which, after capturing PM, emit the exhausts at low velocities with little momentum through monitor vents that generally extend the length of the baghouse. As such, the “stack height” for such sources reflects the height of the baghouse itself, which is typically less than 100 feet.

Commenter (0504) continues, given the large areas at the exhausts of the baghouses, effective “diameters” of the rectangular exhaust are tens of feet. Further, to avoid replacing bags prematurely, companies maintain exhaust temperatures at very low levels, which results in low-buoyancy emissions. In short, the low velocity, low temperature, low-height emissions from baghouses at EAF meltshops bear little resemblance to tall-stack exhausts such as those used at EGUs. In addition, smaller furnaces, such as those used for annealing, often lack stacks; and when they do, they are very low-level.

Commenter (0504) explains, in many cases, emissions units at EAF steel producers are considered ground-level emissions because they are not ducted to or captured by baghouses. For instance, NO_X from reheat and annealing furnaces are often emitted at ground level because those emissions units are housed in structures that are not controlled by the main baghouses. Even for NO_X emissions from those smaller sources (like ladle/tundish preheaters) that may be controlled by the baghouse by virtue of their presence in the meltshop, these emissions are more accurately construed as ground-level emissions. As the EPA has routinely recognized, these low-velocity ground-level sources are not the types of NO_X emissions sources that tend to transport and contribute significantly to receptors in distant, downwind states. These emissions units also emit NO_X at much lower levels relative to EGUs and other non-EGU sectors. According to the Government Accounting Office and the EPA sources consulted by the Government Accounting O, "total emissions is a key contributor to interstate transport of air pollution. . ." Because of the comparatively small NO_X emissions from these sources, there is less NO_X available in the atmosphere to form ozone that can ultimately be transported downwind.

Response:

As explained in Section VI.C.3 of the preamble, the final rule is not applicable to EAFs. With regard to the commenters concerns regarding modeling and stack height unrelated to EAFs, Section IV.F.1 explains that the CAMx photochemical modeling used to support this rulemaking includes source apportionment of upwind emissions sources that is technically appropriate for stationary point sources, including non-EGU NO_X emissions. This air quality modeling serves as the technical basis for the EPA's conclusion that upwind sources of NO_X from industrial stationary sources are impacting ozone concentrations in downwind areas.

Comment:

Commenter (0359) states the cost per ozone season ton of NO_X reductions averages $9,500 per ton and as high as $16,910 per for each emissions unit (not for the facility) according to the screening assessment. Considering that facilities in this industry have over 25 emissions units per facility, the cost of these non-technically demonstrated proposed emissions limits are exorbitant for one emissions unit, let alone for the entire facility to attempt to comply. The EPA did not address the costs on a per facility basis when it proposed 15 possible types of emissions units within each facility.

Commenter (0798) adds the EPA failed to fully and accurately develop the costs that would be incurred by the iron and steel industry. The EPA claims that the SCR technology and the limits set in the proposed rule would be cost effective but to arrive at that calculation the costs were estimated if technology ran year-round and not just during ozone season (for. Trinity Consultants provides the following information related to their review of the costs associated: "For instance, the EPA estimates that selection of SCR in the Iron and Steel Mills and Ferroalloy Manufacturing Industry may be associated with 948 ozone season NO_X reductions, at an annual cost of $9,886,092. If the EPA had calculated the cost per ozone season ton of NO_X reduced, this would result in an estimate of $10,428 per ton of NO_X reduced, which is well above the cost threshold of $7,500 stated by the EPA). But the EPA instead, without justification, lists the average cost per ton as $4,345, which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions."

Response:

As discussed in Section VI.C.3 of the preamble and elsewhere in this RTC, the final rule only requires a 40 percent reduction from reheat furnaces that do not currently have low-NO_X burners installed. The EPA is not requiring SCR on reheat furnaces. As discussed in the preamble at Section V.D., the EPA has updated its cost estimates in Step 3 based on information received during public comment. Annual cost-per-ton estimates are consistent with the EPA's longstanding approach to presenting cost-per-ton figures in the Step 3 analysis.

The requirements for boilers are addressed in Section VI.C.5 of the preamble.

Comment:

Commenter (0798) concludes in the proposed rule, the EPA started from a limit that was the lowest emissions rates identified in any prior RACT or BACT analysis and inexplicable applied additional controls that would lead to arbitrary and unsustainable additional reductions. These reductions were based on control technologies never before applied to these emissions units and only based on incorrect generic assumptions. The EPA uses similar approaches for the proposed emissions limits for all steel units in proposing emissions limits far below those determined as either BACT or RACT in unit-specific analyses. This all further supports that the EPA used a flawed methodology in the development of the proposed rule. Commenter (798) further notes that it is illogical and inappropriate for EPA to now require an unjustified, unproven (and infeasible) limit that is significantly lower than BACT or LAER.

Response:

As discussed in Section VI.C.3 of the preamble and elsewhere in this RTC, the final rule only requires a 40 percent reduction from reheat furnaces that do not currently have low-NO_X burners installed. The EPA has determined in the final rule that low-NO_X burners are widely available across the Iron and Steel industry for reheat furnaces and are cost effective. A further explanation of the units that have installed low-NO_X burners on reheat furnaces is included in the Final Non-EGU Sectors TSD.

Comment:

Commenter (0798) states Hot Strip Mills are specifically designed operations, and any addition of equipment or technology requires significant planning, engineering, time, and money. The EPA's failure to understand the complicated operations at a hot strip mill has led to the proposed rule significantly underestimating the difficulty that would be involved in retrofitting the prescribed emissions control equipment in the proposed rule. The cost and ability to retrofit equipment within a hot strip mill is going to be extremely difficult and require significant modification to operations. A retrofit of this nature will also cause significant downtime and associated loss of revenue. The proposed SCR technology if it is even capable of being installed will require extensive modification to accommodate the changes.

Commenter (0798) continues, the U. S. Steel Gary Works facility as well as other facilities have completed a RACT analysis for hot strip mill operations related to Regional Haze. Operations at these facilities have already been modified to meet the RACT requirements. The proposed rule attempts to regulate beyond the requirements already in place, through what can only be characterized as a "beyond- LAER" emissions limit. LEAR. All of the changes (for all integrated iron and steel operations) in the proposed rule will have a minimal impact on attainment in downwind states. Continuing to push for unproven and very costly technology to be applied with little to no appreciable improvement is not the purpose of this section of the CAA. Reheat furnaces are used to reheat slabs of steel to work and shape the steel into another product. The reheat furnaces use uniform heat and hold the desired temperature for a set time. The design and operation of reheat furnaces makes SCR technology infeasible.

Commenter (0280) continues, the EPA's definition would also apply to "tunnel" furnaces that are used in the EAF sheet mill industry. A tunnel furnace is a long furnace capable of holding an entire slab and bringing it to a consistent temperature. Commenter (0280) operates multiple tunnel furnaces that are "mobile" – *e.g.,* they roll back and forth between the caster and the start of the rolling operation to provide timing support and allow continuous casting and eliminate duplicate rolling operations. These mobile "tunnel" furnaces, often called "shuttle" furnaces, are usually vented through monovents and are not routed to stacks because of their mobile nature. Application of add-on controls such as SCR or SNCR to an existing mobile furnace would be technically difficult, if not wholly infeasible, due to space constraints, limitations on motors and relays, and a myriad of other technical details. Additionally, the additional controls suggested by this propose rule would be cost prohibitive.

Commenter (0504) states to derive the proposed 0.05 lb/mmBtu NO_X limit for reheat furnaces, the proposed FIP used as a baseline the 0.073 lb/mmBtu limit determined to be achievable using Low-NO_X burners in Sterling Steel's 2019 permit, and "assume[d] 40 percent reduction." Here again, the preamble to the proposed FIP and the Proposed Non-EGU Sectors TSD disagree about the types of controls the EPA presumes can achieve the surmised 40 percent NO_X reduction from reheat furnaces. The preamble "assume[s] 40 percent reduction by SCR," while the Proposed Non-EGU Sectors TSD "projects minimally 40 percent NO_X reduction efficiency is achievable by use of low-NO_X burner technology, including potential use of new generation of low-NO_X burners or optimization of existing burners." As such, both of these records presume the exact same remarkable emissions reduction potential, but for entirely different reasons. Moreover, the Proposed Non-EGU Sectors TSD based its presumption that companies could reduce NO_X emissions from reheat furnaces to 40 percent of the 0.073 lb/mmBtu from the 2019 Sterling Steel permit by the "use of low-NO_X burner technology," that the EPA's preamble recognized to be already in use in Sterling Steel's reheat furnace.

Commenter (0504) notes given the divergent technologies on which the EPA based the same 40 percent NO_X emissions reduction potential, it is thoroughly unclear how the EPA selected the 40 percent value. Elsewhere in the Proposed Non-EGU Sectors TSD, the EPA identifies NO_X reduction potential of up to 77 percent]. This reduction percentage is taken directly from Section 5.3.6 of the 1994 ACT. It is clear from the baseline NO_X levels in the few reheat furnaces tested in the 1990s were very high – *i.e.,* 0.689 lb/MMBtu for regenerative furnaces. While low NO_X burners and FGR reduced this to 0.18 lb/MMBtu, resulting in around 74 percent NO_X reduction, this is because of the high baseline. Thus, this unexplained alternate NO_X emissions reduction presumption fails to recognize that most of the reheat furnaces in operation today in the steel industry have considerably lower NO_X emissions levels than 0.689 lb/MMBtu. In fact, most of the current furnaces have baseline emissions levels that are closer to or even lower than the 0.18 lb/MMBtu controlled NO_X level noted in the 1994 ACT because such furnaces already use LNB or ultra-LNB. Of course, obtaining 77 percent (or 74 percent) NO_X reduction using LNB+FGR is not feasible when the starting point already includes LNB or ultra- LNB. Thus, the EPA's fundamental premise for further NO_X reductions from reheat furnaces is not grounded in fact with regards to the current baseline NO_X levels from such furnaces.

Commenter (0504) believes the EPA's proposed FIP fails to recognize that many EAF steel facilities' reheat furnaces move within the facilities and do so in a way that significantly limits the options for add-on controls. "Tunnel" or "shuttle" furnaces are designed and operated to roll back and forth between the caster and the start of the rolling operation to allow for more continuous casting and eliminate duplicate rolling operations. These types of reheat furnaces are usually vented through monovents and are not routed to stacks because of their mobile nature. Application of add-on controls such as SCR or SNCR to an existing mobile furnace would be technically difficult, if not wholly infeasible, due to space constraints and other technical details.

Response:

The EPA is not finalizing the proposed emissions limits for reheat furnaces that would have likely resulted in the installation of SCR or other post-combustion control technology. As discussed in Section VI.C.3 of the preamble and elsewhere in this RTC, the final rule only requires a 40 percent reduction from reheat furnaces that do not currently have low-NO_X burners installed. The EPA has determined in the final rule that low-NO_X burners are widely available across the Iron and Steel industry for reheat furnaces and are cost effective. A further explanation of the units that have installed low-NO_X burners on reheat furnaces is included in the Final Non-EGU Sectors TSD.

5.3.3.3 Emission Limits

Comments:

Commenter (0360) expresses concerns that with the short term of the proposed effective date of the limitations, supporting infrastructure and science is not yet advanced to a point where an immediate shift in say technology for reheat furnaces is feasible for full scale, industry wide implementation. Therefore, fossil fuel combustion emissions reductions technologies and stoichiometric (tuning) adjustments are likely the most feasible means towards attempting to comply with the proposed lower emissions standards for sources such as reheat furnaces. The commenter explains that for optimum stoichiometry, operators usually target a 10:1 air-to-fuel ratio, and excessively low NO_X emissions limitations will force industries to operate combustion sources in a fuel-rich environment, which will inevitably result in higher local and ambient CO emissions.

Commenter (0416) claims that the EPA based the proposed rule on multiple assumptions without any industry input. According to the commenter, to arrive at an emissions limit, the EPA chose an uncontrolled emissions limit or rate from among dozens of such limits or rates, assumed a control technology, and then randomly chose a percent reduction from a range of possible percent reductions for that control technology. The commenter asserts that this compounding of assumptions on top of assumptions calls into question the EPA's approach for setting emissions limits and the basis for and viability of such limits. The commenter remarks that a rule is arbitrary and capricious if there is a lack of a reasonable explanation, and this position by the courts seems imminently reasonable given the subject here is a regulation that would impose enormously burdensome requirements on the iron and steel industry that would achieve at best negligible and highly questionable actual benefits to society. The commenter adds that the standard practice for NO_X limit setting on process industries (non-EGUs) often requires site or unit-specific control and limit setting ability to overcome unique issues at a particular mill.

Commenter (0280) states the EPA proposes to regulate reheat furnaces, defined as "a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing." Proposed 40 CFR 52.43(a) Reheat furnace. The EPA proposes a limit of 0.05 lb/mmBtu based on SCR plus low NO_X burners. Proposed 40 CFR 52.43(c), Table 1. In the preamble, the rationale for this is the Sterling Steel permit with low-NO_X burners at 0.073 and the Ohio RACT limit at 0.09 lb/mmBtu and an "assumed" 40 percent reduction by SCR [28]. Assuming the feasibility of adding an SCR without providing a technical evaluation is inappropriate.

Commenter (0359) states the screening assessment does not include any reheat furnaces. The justification for the proposed NO_X emissions standard of 0.05 lb/mmBtu for reheat furnaces, which is almost twice as stringent as the Ohio RACT limit, assumes a 40 percent reduction with the installation of SCR. Commenter (0405) states in Table V11.C-3 of the preamble, part of the EPA's basis for the proposed limit is Ohio EPA's NO_X RACT limit of 0.09 lb/MMBtu. [87 FR 20145] The EPA then applies an arbitrary SCR removal efficiency of 40 percent on top of RACT to arrive at a proposed limit of 0.05 lb/MMBtu. However, the EPA did not recognize that numerous reheat furnaces at steel facilities in Ohio have unit specific RACT limits (found at Ohio Administration Code (OAC) 3745-110-03(J)) that were established based on extensive studies which determined that Ohio EPA's generic NO_X RACT limit of 0.09 lb/MMBtu was not technically feasible and/or economically reasonable. For example, Cliffs' Cleveland Works facility has unit-specific RACT limits above the arbitrary 0.09 lb/MMBtu limit proposed by the EPA. The Cleveland Works facility RACT limits are based on a 'slab' reheat furnace specific engineering report from an expert reheat furnace burner consultant. U.S. Steel's Lorain Tubular Operations also have unit specific RACT limits for its 'rotary' and 'seamless mill' reheat furnaces above the generic 0.09 lb/MMBtu limit referenced by the EPA.

Commenter (0405) continues, the EPA also cited a Sterling Steel permit for a new "billet" reheat furnace, issued in 2019. A recent permit for a new source is not applicable to a RACT analysis, which must consider the unit specific characteristics of an individual furnace and furnace type, as well as all of the retrofit limitations/restrictions and total installed costs applicable to retrofit a specific existing reheat furnace. To comply with the EPA's proposed limit for reheat furnaces, these units would need to achieve removal efficiencies ranging from 60-85 percent, far higher than the EPA's arbitrarily selected removal of 40 percent.

Commenter (0405) argues there is no guarantee that these units could comply with the EPA's proposed emissions limit even with SCR installation. Cliffs is aware of one SCR installation on a reheat furnace in the steel industry that was issued a PSD permit in 2003 requiring operation of SCR on a slab reheat furnace. However, as noted in a response to comment document provided with the permit, the source submitted an application to increase the NO_X emissions limit for the reheat furnace because "the non-steady state nature of the reheat furnace made it impossible to achieve a consistent level of SCR performance". Reheat furnaces have door(s) that continually open and close to allow a reheated slab or other form of steel to exit the furnace. The batch reheat furnace process of opening and closing the door(s) results in swings of the furnace exhaust temperatures that is detrimental to a successful SCR application.

Commenter (0405) continues, even the most stringent BACT limit for new reheat furnaces in the steel industry based on the only known SCR application is more than 50 percent higher than the EPA's proposed limit in this rulemaking. Given the documented performance issues with operating an SCR on a reheat furnaces and given that most reheat furnaces have considerably higher uncontrolled emissions compared to the EPA's starting point in the proposed FIP, there can be no reasonable assurance that compliance with the EPA's proposed limit is even possible. These RACT determinations and an unsuccessful application of SCR on a new reheat furnace are further support for Cliffs requesting that the EPA remove its proposed limit for reheat furnaces from the rulemaking. Any future RACT emissions limits for reheat furnaces must be developed using the time proven RACT methodology of evaluating each unit on a case-by-case basis.

Commenter (0798) evaluated RACT from Trinity Provides for a reheat furnace in 2014. However as expected "That analysis found that the cost of adding low NO_X burners would be \$14,100/ton, which is not cost effective." The U. S. Steel Gary Works facility then conducted a BART analysis for reheat furnaces in 2020. The BART analysis found that the cost of adding low NO_X burners would be \$14,100/ton, which is not cost effective under the purported cost threshold of \$7,500 that the EPA arbitrarily set forth iron and steel units in the proposed rule. Due to the heat needed these burners would likely increase the energy use as well. Creating another expense and likely increasing air emissions. Again, the EPA fails to understand the iron and steel industry and does not show that the proposed rule meets its purpose to improve air emissions related to NO_X.

Commenter (0758) states for reheat furnaces, the EPA proposes a NO_X limit of 0.05 lb/mmBtu. However, reheat furnaces are regularly subject to limits around 0.07, or lower, with low or ultra-low NO_X burners alone. Thus, the EPA's proposed limit of 0.05 lb/mmBtu is likely achievable with additional pollution reductions, such as flue gas recirculation and SCR, which has been used to control NO_X emissions from reheat furnaces since 1999.

Response:

As suggested by some commenters, the EPA is finalizing a requirement for combustion control technology for reheat furnaces and is not requiring the installation of SCR or setting emissions limits that would require SCR to meet those limits. Specifically, as discussed in Section VI.C.3

of the preamble and elsewhere in this RTC, the final rule requires a 40 percent reduction from reheat furnaces that do not currently have low-NO_X burners installed. The EPA has determined in the final rule that low-NO_X burners are widely available across the Iron and Steel industry for reheat furnaces and are cost effective. A further explanation of the units that have installed low-NO_X burners on reheat furnaces is included in the Final Non-EGU Sectors TSD.

Any comments regarding the identification of Iron and Steel facilities and reheat furnaces in Step 3, the Screening Assessment, or concerns with the representative costs identified in the final rule are addressed in Section V of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).

Comments:

Commenter (0300) questions why the EPA is referencing 40 CFR 63.6(e) under 40 CFR 52.43(d), since due to significant federal litigation regarding the startup, shutdown, and malfunction provisions in 40 CFR 63.6(e), the EPA has been revising all the NESHAP standards to remove reference to the provisions of 40 CFR 63.6(e). The commenter further adds that they do not believe it is appropriate to reference standards designated for HAP in part 63 rather than criteria pollutants, particularly NO_X, addressed in part 60.

Response:

The final rule regulatory text does not reference 40 CFR 63.6(e). Additionally, the new work plan requirement for reheat furnaces does not have any exemptions for startup, shutdown, and malfunction for Iron and Steel facilities.

Comments:

Commenters (0280, 0294, 0336, 0504) argue that the proposed rule should not impose presumptive limits on steel melting and finishing furnaces and boilers because these sources are already subject to a comprehensive set of regulations reducing NO_X emissions more stringent than RACT or BACT requirements across the country. According to the commenters, the EPA's proposed limits for the six types of emissions units at EAF steel producers are universally lower than the most stringent classes of emissions limits identified under the CAA.

Commenter's (0294) sources are currently subject to emissions limits, control requirements, and work practices that represent BAT and/or BACT. According to the commenter, sources subject to the standards are already subject to the maximum degree of reduction as permitted, and the proposed rule would unilaterally revise these prior determinations despite the lack of any new or modified equipment. Based on a review of control technology determinations in USEPA's RACT/BACT/LAER Clearinghouse, combustion strategies (*e.g.*, modified burners, staged combustion, oxygen enrichment) represent the maximum degree of NO_X reduction for the types of emissions units in the proposed rule.

Response:

The EPA acknowledges that some affected units may already be meeting the emissions limits or plan requirements for reheat furnaces in this rule as a result of controls installed to comply with other regulatory programs, such as the CAA's RACT or BACT requirements. However, emissions from the universe of iron and steel units 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.

Comment:

Commenters (0294, 0300, 0405, 0416, 0504, 0798) state that each affected unit with emissions limitations in the proposed FIP varies significantly in design and operation, and these differences in result in significantly different NO_X formation mechanisms and emissions profiles. The commenters remark that many of the general RACT limits for existing sources used as starting points by the EPA in the proposed FIP are limits that were ultimately adjusted upward after completion of comprehensive site-specific technical feasibility and economic reasonableness analyses, which is the correct mechanism by which to establish a source-specific emissions limitation. Similarly, the commenter adds that the EPA's approach of selecting a single BACT emissions limit established for a new source and assuming it can be applied to existing units in an entire industry results in arbitrary limits that are not possible to achieve.

Response:

With regard to reheat furnaces, the EPA is not prescribing one specific control technology, but instead requires a specific reduction efficiency for reheat furnaces (40%) and certain other monitoring, testing, and recordkeeping requirements to ensure reductions are achieved. The EPA acknowledges some affected units may already operate reheat furnaces and those will not need to take any further action to install controls.

Comment:

Commenters (0280, 0294, 0301 0405, 0416, 0505, 0504) notice that the proposed FIP references both a 3-hr average and a 30-day rolling average as the compliance method for the Iron and Steel sector. According to the commenters, imposing a 3-hr rolling average compliance period only on the Iron and Steel sector is without technical justification and provides no tangible benefit compared to a 30-day rolling average in terms of reducing ozone season transport. The commenters assert that since this rule is intended to address long-range ozone transport, imposing a 3-hr rolling average, which addresses short-term variability in emissions, has no appreciable impacts on ozone concentrations hundreds or thousands of miles downwind. The commenters add that the lengthy transport time, climatology, atmospheric mixing, and reaction chemistry render hour-to-hr variations in NO_X emissions from upwind sources meaningless to downwind monitors.

Commenter (0405) adds, that by the EPA's own admission in the preamble to the proposed FIP, a 30-operating day rolling average provides a far more reasonable balance between a short term and an annual averaging period while accounting for the highly variable nature of steel operations [see 87 FR 20145]. The commenter (0405) concludes that requiring short-term averaging periods for the Iron and Steel sector is arbitrary and capricious. The commenter adds that EGUs, the largest NO_X sources, are only required to meet trading allocations over the May- September control period. Likewise, the commenter adds that states such as Ohio and Indiana require the use of NO_X controls on non-EGUs during the May-September ozone season. According to the commenter, the EPA has not provided a justification for proposing a compliance period 240 times more stringent for the Iron and Steel sector alone, compared to the 30-day rolling average period, or 1,224 times more stringent compared to the EGU and non-EGU May- September control period. The commenter asserts that the compliance averaging period for the Iron and Steel sector should be no more stringent than the compliance period for EGUs and other non-EGU sectors and requests that the EPA specify that compliance with any emissions limits for the Iron and Steel sector be evaluated over an ozone season (*i.e.,* May-September).

Commenters (0405, 0504) presume this singular reference to a “3-hr rolling average” is a typographical error because it is fully inconsistent and irreconcilable with the EPA’s analysis in the preamble to the proposed FIP. The commenters also note that it is inconsistent with the entirely of the EPA’s technological feasibility analysis, the averaging times the EPA is proposing to apply to other non-EGU sector sources, and even other portions of the regulations the EPA proposed for the “Iron and Steel Mills and Ferroalloy Manufacturing Industry” in proposed Section 52.43.

Commenters (0405, 0416) believe the EPA intended to propose a 3-hr average rolling compliance period with use of a NO_X CEMS. Commenter (0405) maintains that the EPA should allow alternative monitoring requirements to demonstrate compliance similar to what it approved in Ohio EPA’s 2019 SIP revisions. The commenter states that barring those changes, for any emissions unit where the EPA requires CEMS, a 30-day rolling average should be the required averaging period.

Commenter (0416) continues, the EPA is significantly increasing the stringency of the NO_X emissions limit by decreasing the averaging time. An emissions standard consists of three interconnected elements: (1) the numerical limit; (2) the averaging time; and (3) the compliance demonstration method or measurement. An adjustment to any of these elements will affect the stringency of the limit. By substantially reducing the averaging time from a 30-day rolling average to a 3-hr rolling average (a 99.5 percent reduction), the EPA has dramatically increased the stringency of the emissions limit. Therefore, if the EPA intends to change from a 30-day rolling average to a 3-hr rolling average, it needs to increase the NO_X emissions limit by a commensurate amount to avoid creating a substantially more stringent limit or limit that cannot be achieved even with the proscribed control technology applied.

Commenter (0416) argues all other non-EGU manufacturing industry categories in the proposed rule are subject to 30-day rolling averages, not 3-hr rolling averages. There is no technical basis for applying a substantially more stringent averaging time to the iron and steel industry than every other industry in the proposed rule.

Commenter (0416) concludes, a 3-hr rolling average is unnecessary to address regional transport of ozone and compliance with the ozone NAAQS. Given this rule is intended to address long-range transport of ozone, it is technically obvious that short-term variability in emissions has no appreciable impacts on ozone concentrations hundreds or thousands of miles downwind. The lengthy transport time, climatology, atmospheric mixing, and reaction chemistry render hour to hour variations in NO_X emissions from upwind sources meaningless. Therefore, there is no basis for this rulemaking to require short-term averaging periods to achieve its intended outcome. Commenter (0416) asserts that there is no technical reason to treat non-EGUs differently than EGUs as it relates to compliance averaging times. EGUs, as the largest NO_X emitters in the proposed rule, are subject to limitations across the entire ozone season (May to September). As such, an equivalent compliance averaging time should likewise apply to non-EGUs. At a minimum, however, to the extent iron and steel emissions units remain in the rule, the averaging time should be no less than a 30-operating day rolling average. Anything more stringent is inconsistent with other portions of the proposed rule and thus arbitrary and capricious.

Commenter (0758) support the EPA's proposed 3-hr rolling average compliance period and proposal to require continuous emissions monitoring to assure compliance with proposed NO_X emissions limits. 87 Fed. Reg. at 20,181.

Response:

The final rule makes clear that the applicable averaging time for reheat furnaces is a 30-day rolling average.

Comment:

Commenter (0798) notes boilers used at integrated iron and steel facilities vary greatly as will the NO_X emissions rates. These boilers will also have a variety of fuel sources and operating parameters. Each boiler would have to be evaluated as to the potential to reduce NO_X emissions, the technical feasibility of SCR and the cost effectiveness. Commenter (0798) conducted a BART analysis on the Clairton facility boilers in 2022. That analysis showed the SCR annual cost effectiveness was at minimum $20,873/ton on Boiler 2, and more expensive on others.

Commenter (0798) continues, some of the boilers already combust BFG which is low NO_X and considered a best practice. This is significantly better from an environmental perspective than an alternative like natural gas that would displace the BFG and increase air emissions. Any modification of boilers would require significant modification to attempt to accommodate SCR. This would not only be costly but would likely produce negative air impacts, especially if boilers were switched to natural gas. Boilers are yet another area where the EPA need to evaluate in more detail, likely through a separate rulemaking or individual RACT determinations, to justify the emissions limits, it purports to apply "wholesale" to boilers in the proposed rule.

Response:

The rationale for the emissions limits and the applicability for boilers is addressed in Section VI.C.5 of the preamble. This section also addresses the use of other fuels in boilers besides coal, natural gas, residual oil, and distillate oil and explains that the final rule is only applicable to boilers that burn more than 90 percent or more of the applicable fuels.

Any comments regarding the identification of Iron and Steel facilities, boilers and reheat furnaces in Step 3, the Screening Assessment, or concerns with the representative costs identified in the final rule are addressed in Section V of the preamble and in Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).

5.3.3.4 Monitoring, Recordkeeping, and Reporting

Comment:

Commenters (0280, 0405, 0416) recommend that the EPA not require CEMS across the board for all categories or even for just some categories. Rather, the EPA should consider only requiring CEMS for sources that are actually emitting at significant NO_X levels, for example, those greater than 1,000 tpy of actual emissions. CEMS requirements should be reserved for only the most significant sources.

Commenter (0300) recalls that 40 CFR 52.43(d)(2) requires installation of NO_X CEMS on affected emissions units, though it does not provide a compliance date for doing such. The commenter warns that this regulation could require CEMS on multiple units, many that are likely natural gas-fired furnaces or heaters with potential NO_X emissions less than 10 tpy.

Commenter (0405) highlights CEMS installation costs would be at minimum $175,000, along with at least $50,000 in annual compliance costs related to CEMS maintenance and QA checks for each emissions unit, resulting in astronomical costs for iron and steel companies. In contrast, a NO_X stack test can be completed for approximately $10,000-$15,000, a small fraction of CEMS costs, while providing the same level of compliance assurance relative to the stated intent of the rule (*e.g.*, impacts over an ozone season). Ohio, which has direct experience working with regulated entities on CEMS considerations, recommends in its comments on the proposed FIP that “EPA consider the costs associated with deployment and ongoing operation of CEMS when performing the cost-benefit analysis and taking into consideration the marginal cost threshold under the EPA’s screening analysis. . . [and] not require CEMS across the board for all categories or even for just some categories.”

Commenter (0416) continues, the EPA’s proposed broad-brush implementation of CEMS ignores the reality that for certain sources the implementation of certified CEMS is simply infeasible. And this broad- brush propose approach also results in the potential for sources to install very costly monitoring devices to monitor de minimis source of NO_X. Either of these outcomes is flawed and in error. Commenter (0416) believes, given this precedent, it is unreasonable now for the EPA to require CEMS for the iron and steel emissions units. The added expense and complications of a CEMS is not offset by any need for discrete, continuous emissions data from these emissions units. Commenter (0416) therefore requests that the EPA rely upon the broadly-applicable, industry-standard approach for ensuring compliance with an emissions limit through the requirement for periodic stack tests to develop emissions factors. These emissions factors can then be assessed against monitoring of tons of steel production or MMBtu of fuel consumed to assure continuous compliance.

Commenter (0798) states that the EPA has failed to justify both why CEMS are “appropriate” and “necessary” in this wholly different context of unit specific performance rates, especially in light of the fact that other programs (NSPS, NESHAP, PSD, etc.) merely require initial performance testing and periodic confirmatory testing to verify unit specific performance limits. The commenter asserts that the EPA wholly fails to provide any persuasive differentiation here in the absence of emissions trading.

Commenters (0280, 0416, 0798) argue that CEMs is not needed for non-EGU units not subject to an allowance trading program. According to the commenters, a CEMs may make sense for large EGU units that operate on an allowance system. In that case, a CEMs allows the source and agencies to evaluate the number of tons of NO_X emitted and to surrender allowances as needed or to sell excess allowances to another source. In such a system, the total mass emitted is critical to ensure that the allowances are achieving the design objective and to ensure that a source does not profit by selling allowances that were not earned by overcontrol. In the case of the command-and-control regulations contemplated for Iron and Steel sector sources, what is critical is the rate of emissions. There are no allowances that must be tracked.

Commenters (0416, 0798) note in the proposed rule preamble, the EPA identified the fact that non-EGUs, including iron and steel emissions units, were not being included in the trading program. The EPA went on to state that if such units were included in the trading program, it would necessitate reporting and monitoring under part 75, including CEMS. The EPA’s basis to require CEMS for emissions units that are part of a trading program is to require “consistent and accurate measurement of emissions ... to ensure each allowance accurately represents one ton of emissions and that one ton of reported emissions form one source would be equivalent to one ton of reported emissions from another source.” Logically, therefore, since iron and steel emissions units are not part of the trading program and there is no need to impose rigorous monitoring to ensure “one to one” equivalency across source, CEMS are unnecessary. The EPA nonetheless has proposed to require CEMS on all subject iron and steel emissions units.

Commenter (0416) continues, the EPA’s approach with this proposed rule is inconsistent with the Agency’s prior actions with other transport rules that include a trading program from only some sources. In particular, in 1988, the EPA issued the NO_X SIP Call under the good neighbor provisions of the CAA. One aspect of the rule included the NO_X Budget Trading Program, that applied to both EGUs and non- EGUs that were subject to the rule [34]. The EPA required part 75 monitoring and CEMS to ensure reliable, quality-assured mass emissions data, consistent with the EPA’s other allowance trading programs. Successor trading programs, however, removed non-EGUs from their scope. There was therefore no longer a need for rigorous part 75 CEMS monitoring for non-EGUs. In response to these scope changes, the EPA revised its regulations to allow states greater flexibility in monitoring non-EGUs by making part 75 CEMS requirements merely optional [36]. The EPA acknowledged that CEMS were unnecessary when the emissions unit was no longer part of a trading program.

Commenters (0280, 0345, 0405, 0798) state the proposed rule assumes that each different unit is stacked such that its emissions could be disaggregated from other units, but that is not the case. The commenters note that some units share a joint stack, some have multiple stacks, and some are so minor as to not be stacked. Accordingly, the commenters state that the proposed rule, if finalized, must allow for flexibility in demonstrating compliance with associated emissions limits.

Commenter (0280) argues that for units without existing ductwork, there is no practical way to install a CEMs, which is the case for most ladle and tundish preheaters, bell annealing furnaces, and mobile reheat furnaces. The commenter states that requiring a CEMs is tantamount to requiring that these units be replaced.

Commenter (0345) requests that the EPA withdraw the requirement to use CEMS to monitor emissions from ferroalloy operations. The commenter states that the 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. The commenter adds that while the EPA initially required a continuous baghouse monitoring system in the Ferroalloy NESHAP RTR, it reconsidered this requirement only a few years ago and allowed the use of periodic opacity observations. See 82 Fed. Reg. 5401 (Jan. 18, 2017).

Commenter (0345) specifies that the open nature of EAFs prevent all emissions from being captured by the hood and vented through the ductwork to the control device. The commenter adds that acknowledging this complexity, the RTR for subpart XXX imposed emissions limits for gases captured by the hood and a separate opacity emissions limit for the shop building fugitive emissions, noting that visual emissions observations can reasonably detect opacity from any number of openings at the facility. According to the commenter, CEMS cannot feasibly be installed on all such openings, and the highly variable airflow within the building would make reliable, consistent readings even more difficult.

Commenter (0405) believes there is a need for case-by-case assessments overall, and the case for reheat furnaces is further exemplified by the operations at Cleveland-Cliffs' Middletown Works. The commenter relays that the Middletown Works operates four slab reheat furnaces that are combined with waste heat boilers, and each slab reheat furnace exhausts its products of combustion through a waste heat boiler that is located immediately above the slab reheat furnace with the combined emissions conveyed through a single stack. According to the commenter, due to this configuration, it is impossible to differentiate NO_X emissions between the slab reheat furnaces and the waste heat boilers, and it is technically impracticable to establish compliance with individual emissions limits based on a CEMS or other "end of stack" measurement.

Commenter (0798) notes that the proposed rule establishes separate limits for EAFs, LMFs, and ladle/tundish preheaters. The commenter notes that these and other small units are typically hooded and exhausted through the same canopy system to the baghouse, where the joint emissions then vent to the baghouse and the primary exhaust stack. Accordingly, it is not possible to separately these unit emissions with CEMS, or to verify separate emissions limits, since any compliance demonstration, whether by CEMS or stack testing, will necessarily be based on a joint measurement of emissions from the stack. The commenter notes that to the extent the final rule still imposes command- and-control limits for individual emissions units, the final rule should take this reality into account by either creating a joint limit for units ducted to the same stack or by allowing emissions to be aggregated for purposes of any compliance demonstration of their combined limits. Furthermore, the commenter notes that some units may be over the 100 tpy threshold while others are under it. Thus, the commenter states that the EPA should clarify how compliance with the proposed emissions limits will be demonstrated, given the fact that any CEMS installed on a stack will reflect emissions from all the units ducted to that stack, and some units may not be subject to limits under the proposed rule.

In contrast, commenter (0798) notes that some units could have multiple stacks per unit. The commenter states that it cannot be assumed that these could be redesigned to a single stack. Accordingly, the commenter asserts that when performing cost estimates to determine the appropriateness of any efficiency limits the EPA proposes for such units, the EPA must take into account the cost of multiple SCR and CEMS rather than assuming that a single CEMS and SCR could be installed on such units.

Commenter (0798) states annealing units can vary greatly in size and amenability to controls. For example, the commenter notes that the batch annealing furnaces at the U. S. Steel BRS facility (and the EV facility under construction) entail such small amounts of emissions that they are not stacked and thus cannot be subjected to unit specific SCR, much less CEMS.

Commenter (0523) states that there are feasibility issues associated with a NO_X CEMS for certain equipment. The commenter remarks that it would be unreasonable to require a CEMS to measure NO_X from a PCM or hot car because there is little to no NO_X present at these operations, and the minimal levels of NO_X are attributable to the inherent nature of the operations, rather than the performance of an add-on pollution control device. The commenter adds that the PCM and hot car are mobile equipment operating in extreme, heavy-duty conditions, and there is significant movement and vibration at these units as they traverse along rail lines at a non-recovery coke facility. The commenter also notes that significant daily maintenance is required to keep these units operational. The commenter further adds that the continuous batch nature of their processes along with the short height of their stacks prevents the fully developed gas flow required for accurate measurements. The commenter remarks that their hot car stack must be short to pass below stationary equipment and the presence of 2,000°F coke and hot steam would further interfere with CEMS operation for their hot cars. The commenter notes that previous stack tests for other pollutants at the PCM and hot car have been performed using bag samples instead of a CEMS due to the harsh and unique operating conditions.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble. The final rule does not require CEMS in all instances and allows for owner or operators to use CEMS or parametric monitoring and stack testing to be used to demonstrate compliance.

To the extent commenters are raising concerns regarding monitoring, recordkeeping, or reporting for emissions units besides reheat furnaces or boilers, the EPA is not finalizing requirements for blast furnaces, basic oxygen furnaces, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or electric arc furnaces as proposed. See Section VI.C.3 of the preamble and the Final Non-EGU Sectors TSD for a further discussion.

Comment:

Commenter (0405) states in § 52.43 of the proposed FIP, paragraphs (d) Compliance and Monitoring Requirements; (e) Recordkeeping Requirements; and (f) Reporting Requirements are not consistent with the Minnesota and Michigan Regional Haze FIP requirements. Further, the proposed FIP imparts duplicate or additional obligations beyond the Regional Haze FIPs, some of which are contradictory. For example, the Regional Haze FIPs are based on NO_X reduction technologies that are technically achievable on a site-by-site specific basis, not to a specific percent reduction as described in the proposed FIP. As another example, §52.43(f)(1) requires certain facilities to submit a work plan with historical performance tests to serve as the baseline for NO_X emissions from which a 40 percent NO_X reduction must be achieved. This requirement would replace NO_X emissions limits contemplated in the Regional Haze FIP. Significant efforts have been expended by Cliffs to ident the EPA clearly states in its technical support for the proposed rule that CEMS are the best method for demonstrating compliance because of the variability in furnace operations and variable fuel usage across the furnaces. The variable fuel feeds and feed material content can impact overall emissions from the process and thereby create the need for continuous monitoring of emissions that impact visibility. Parametric emissions monitor systems are an option for processes that operate at stable, nonvariable conditions, but are not appropriate for taconite units. CEMS provide a continuous record of data that can also be used by the facility owner or operator to monitor emissions on a real-time basis. The installation and operation of CEMS and the real-time evaluation of the CEMS data provide several benefits to a facility that can directly lead to practices that reduce emissions during all periods of operation and implement technically feasible and cost-effective NO_X emissions reductions as part of the Minnesota and Michigan Regional Haze/BART FIP. The requirements in § 52.43 (d), (e), and (f) are unnecessary, redundant, and in some instances contradictory. For these reasons, commenter (0405) requests the EPA specifically identify the existing taconite Regional Haze FIP obligations as sufficient to satisfy all NO_X reduction, compliance, monitoring, recordkeeping, and reporting requirements associated with this proposed FIP.

Response:

The EPA acknowledges that some affected units may already be meeting the emissions limits or compliance requirements established in this rule as a result of controls installed to comply with other regulatory programs, such as a Regional Haze FIP. In the case that another rule such as Regional Haze FIP has less stringent requirements, this rule does not replace those requirements. Rather, a unit is required to comply with all applicable regulations and standards. Any monitoring, recordkeeping, or reporting required under this final rule is not duplicative of other standards as the compliance requirements of this rule are designed to assure compliance with the standards and emissions limits established in this rule. To the extent that an owner or operator believes that another applicable standard or compliance requirement could be satisfied by meeting the requirements of this final rule, the owner or operator should work with the relevant permitting authority to streamline those requirements in the applicable permit.

A discussion of the modifications made to the proposed compliance requirements in the final rule is included in Section VI.C.3 of the preamble.

Comment:

Commenters (0280, 0405, 0416, 0798) respond to the EPA's request for comment on alternatives to CEMS for ensuring compliance. Commenters (0280, 0416) believe periodic stack testing is sufficient to demonstrate whether the rate is being attained. They state that the CEMS requirement is not needed to assure compliance and merely adds considerable expense and burden to operators and agencies alike. Commenter (0280) asserts that CEMS are not necessary and periodic stack testing along with monitoring of tons of steel production or MMBtu of fuel consumed is more appropriate. Or in the alternative, the commenter says the EPA should defer to state agencies in the permitting process for the new control equipment to determine, on a case-by-case basis, the most appropriate monitoring device. Commenter (0405) maintains that the proposed FIP should allow for the use of stack testing in lieu of NO_X CEMS similar to what has been proposed for the Cement and Concrete category.

Commenters (0405, 0416) note that the EPA revised its NO_X SIP regulations on March 8, 2019, to allow alternative monitoring options in lieu of NO_X CEMS. According to the commenters, the Ohio EPA subsequently revised its NO_X budget program requirements for non-EGUs in 2020 to allow the EPA's approved alternative monitoring options. Commenters (0405, 0416) want the EPA to consider that Ohio EPA allowed non-EGUs that were no longer part of the trading program to propose Alternative Monitoring methods in lieu of part 75 CEMS requirements. The commenters relate that one option afforded to non- EGUs is to monitor heat input and fuel use combined with use of an approved emissions factor. The commenters add that units using the approved emissions factor must conduct stack at least once every five years to confirm representativeness of the emissions factor.

Commenter (0798) states there are many alternatives to CEMS. The commenter points out that for boilers and burner tips, especially, vendor guarantees and known engineering emissions factors for natural gas combustion can be used to track emissions based on natural gas usage/throughput. The commenter opines that this method may also work for furnaces where NO_X emissions derive primarily from coal or natural gas combustion. For any other sources whose NO_X emissions cannot be simply derived by tracking natural gas or coal throughput, the commenter offers that stack testing should be available as an alternative means of compliance.

Response:

The EPA has responded to these comments in Section VI.C. of the preamble. As suggested by some commenters, the EPA has included alternative monitoring and recordkeeping provisions in the final rule for reheat furnaces, including but not limited to monitoring and recording stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature.

To the extent commenters are raising concerns regarding monitoring, recordkeeping, or reporting for emissions units besides reheat furnaces or boilers, the EPA is not finalizing requirements for blast furnaces, basic oxygen furnaces, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or electric arc furnaces as proposed. See Section VI.C.3 of the preamble and the Final Non-EGU Sectors TSD for a further discussion.

5.3.4 Glass and Glass Product Manufacturing

Comment:

Commenter (0416) suggests the removal of the definitions for "*all-electric melter,*" "*experimental furnace,*" and "*rebricking*," noting that neither term is used in the proposed rule. The commenter further implies that other un-used terms need to be removed and suggests that these inconsistencies indicate that the EPA rushed to issue this proposed regulation to meet a court-ordered deadline and did not undergo a complete and thorough review process prior to publication of the proposed rule.

Response:

The final rule does not include these definitions.

Comment:

Commenter (0321) states that the emissions limits that would be applied to periods of startup, shutdown, and idling "appear to be mathematically impossible to meet."

Response:

In response to information provided by commenters, the EPA is finalizing alternative standards for Glass and Glass Product Manufacturing that may apply during startup, shutdown, and idling conditions. These alternative standards are described in Section VI.C.4 of the preamble.

Comment:

Commenter (0321) writes that the time frame for installation of emissions controls "fails to recognize the typical life cycle of glass furnaces and thereby threatens to impose tens of millions of dollars in extra costs, per furnace, by forcing furnaces to shutdown years earlier than they would otherwise be scheduled to do so."

Response:

As explained in Section V.D of the preamble, the EPA has identified an appropriate level of uniform NO_X control stringency for each non-EGU industry covered by the final rule that is cost-effective, widely available, and in use at many other similar non-EGU facilities throughout the country, and based on the air quality results presented in Section V of the preamble the EPA has concluded that the emissions control strategies identified and evaluated in Sections V.B and V.C of the preamble will deliver meaningful air quality benefits that collectively eliminate significant contribution to downwind nonattainment and maintenance receptors in the 2026 analytic year. For the Glass and Glass Product Manufacturing industry, the emissions limits in the final rule can generally be met with combustion modifications (e.g., low-NO_X burners, oxy-firing) but may also be met through process modifications (e.g., modified furnace, cullet preheat) and/or post-combustion controls (SNCR or SCR). The emissions limits for this industry thus provide sources some flexibility to choose the control technology that works best for their unique circumstances. The EPA's rationale supporting the emissions limits in the final rule for the glass industry is provided in Section VI.C of the preamble and section 5 of the Final Non-EGU Sectors TSD.

The EPA has responded to comments about control installation timing needs for non-EGU industries in Section VI.A.2 of the preamble. The EPA also initiated a study to examine the time necessary to install controls at non-EGU industries and, in Section VI.A.2 of the preamble, describes the key findings and underlying assumptions in the resulting report entitled SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023). The EPA's conclusion based on these evaluations is that three years is generally an adequate amount of time for the non-EGU sources covered by this final rule to install the controls needed to meet the emissions limits. 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 circumstances entirely beyond the owner or operator's control. To address these circumstances, the final rule contains a provision allowing sources to request EPA approval of limited compliance extensions beyond the 2026 ozone season, where specific criteria are met. Additionally, the final rule contains a provision allowing sources to request EPA approval of case-by-case emissions limits based on a showing that an affected unit cannot meet the applicable emissions limit due to technical impossibility or extreme economic hardship. We describe these provisions more fully in Section VI.A.2 and Section VI.C of the preamble. We find these provisions adequate to address the commenter's concerns about the typical life cycle of a glass furnace and the costs associated with shutdowns to install controls.

Comment:

Commenter (0418) requests that the requirements applicable to its container glass manufacturing furnaces be omitted or "revised to reflect achievable emissions limits based on valid and representative cost data."

Response:

We respond to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluating potential emissions reductions from these industries, and evaluating related control costs in Section 2.2 (Non-EGU Industry Screening Methodology).

5.3.4.1 Applicability Threshold

NAICS Requirements

Comment:

Commenter (0377) requests that the EPA amend its proposed rule language to clarify that the requirements for the glass and glass product manufacturing industry apply only to facilities operating under NAICS code 3272 to avoid imposing overbroad NO_X reduction obligations beyond those necessary to achieve the Ozone NAAQS. The commenter suggests the following regulatory text to make this clear: "§ 52.44 (b) Applicability. You are subject to the requirements under this section if you own or operate a new or existing glass melting furnace, located at a source that is within the Glass and Glass Product Manufacturing Industry (NAICS code 3272xx), that directly emits or has the PTE 100 tpy or more of NO_X and is located within any of the states listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such state(s).” The commenter is concerned that, absent this change in the proposed language, § 52.44 could be interpreted to apply to facilities that were not included in the EPA’s analysis as requiring NO_X emissions reductions to achieve compliance with the ozone NAAQS in downwind states. According to the commenter, the key basis for their concern is that members of North American Insulation Manufacturers Association operate fiber glass insulation manufacturing facilities that have glass manufacturing furnaces with the PTE 100 tpy or more of NO_X, but that do not fall within NAICS code 3272. The commenter asserts that these facilities are properly categorized under NAICS code 327993, fiberglass insulation products manufacturing.

Response:

The final emissions limits for Glass and Glass Product Manufacturing industry only apply to facilities under the NAICS code 3272. This is consistent with Table III.A-1 of the proposed rule, in which the EPA identified Glass and Glass Product Manufacturing non-EGU sources under NAICS code 3272. See 87 FR 20036.

Comments:

Commenter (0548) notes a typical well-maintained natural gas or hybrid furnace in use within the container glass industry may be operated continuously for as long as fifteen to twenty years between rebricking events. However, as more electric current is passed through the molten glass within a furnace, wear on furnace refractory is increased. Unlike natural gas or hybrid furnaces, the lifetime of an all-electric glass melting furnace is only about three to five years before it must be rebricked [2]. Reduced furnace life, due to high levels of electric current use, increases a glass container plant’s operating costs, along with measured waste disposal at the furnace level.

Commenter (0548) states electric furnaces for manufacture of glass containers are limited to a maximum glass production of only about 120 tons per day (although at least one manufacturer claims it can build an all-electric furnace capable of producing up to 150 tons/day) [3]. This is in stark contrast to large natural gas fired glass melting furnaces, which are capable of producing over 400 tons of glass per day.

Commenter (0548) states cullet percentage is the most impactful sustainability criteria for container glass manufacturing. The use of cullet reduces energy consumption in two ways: 1) The heat required to melt cullet may be 33-50 percent less than that required to produce glass from the virgin raw materials, and 2) the use of cullet requires the addition of fewer additives, thus saving the energy required to mine the inorganic chemicals usually added [4]. Electric glass melting furnaces operate with a “blanket” of “cold” raw batch materials on the surface of the molten glass that act to insulate the furnace and provide proper melting characteristics. Because cullet, unlike other batch materials, tends to sink into the molten glass rather than float on the surface, electric furnaces are limited in the amount of cullet that can be used in the batch; while 100 percent cullet can be used as feedstock for a natural gas-fired furnaces, all-electric glass melting furnaces are limited to maximum of about 30 percent cullet, increasing energy usage.

Commenter (0548) adds while large glass pull changes on a natural gas fired furnaces are relatively easy to achieve, glass pull changes in electric furnaces must be done very slowly and deliberately to properly maintain the raw material "blanket" on the surface of the glass [8, 9, 10]. Large swings in glass pull can upset the melting characteristics and could result in solidifying the glass within the furnace – a catastrophic event.

Commenter (0548) notes while all-electric furnaces can be used to manufacture flint (clear) glass, they are severely limited in their ability to manufacture reduced chemistry green and amber glasses. The association and its members request that actions within the proposed rule targeting glass container industry-specific NO_X reductions be removed, and if to be considered in the future, be addressed in a separate rulemaking proceeding.

Response:

The final rule does not contain any requirement for owners or operators of existing glass manufacturing furnaces to retire and replace their units with all-electric furnaces.

Applicability Based on Production Capacity

Comment:

Commenter (0505) responds to the EPA's request for comment on whether the applicability threshold for cement kilns and glass manufacturing furnaces should be based on a unit's design production capacity instead of the proposed applicability for kilns (emit or have the PTE 100 tpy or more of NO_X). Commenter (0505) agrees that cement kiln and glass manufacturing furnace production capacity is a more relevant determination of applicability and would focus the EPA analysis on cost effective regulations.

Response:

The EPA acknowledges the commenters suggestion. In the development of the emissions standards, the EPA reviewed how applicability for glass manufacturing furnaces was determined in various state RACT NO_X rules, air permits, consent decrees, and federal regulations applicable to glass manufacturing furnaces. Based on the EPA's review, the applicability determination implemented for glass manufacturing furnaces were mostly expressed in terms of actual emissions or PTE. The EPA finds this form of applicability is convenient and consistent with applicability practices conducted for the Glass and Glass Product Manufacturing source category. Given the significant differences between glass furnace designs, configurations, age, fuel capabilities, furnace type, and differences in raw material compositions within the sector, the EPA finds that this form of applicability provides the most appropriate way in capturing heavier emitting glass manufacturing furnaces that contribute NO_X emissions to downwind receptors. The EPA received several comments on the proposed NO_X emissions standards from numerous representatives of the glass industry, and no other objections were made to the EPA relying on PTE to determine applicability for glass manufacturing furnaces.

Other Comments

Comment:

Commenter (0356), representing the only cellular glass manufacturing facility in the US, claims they are miscategorized in certain docket filings for the proposed rule and correct the specified documents or add a separate corrective filing in this docket to avoid confusion in future applicability analyses. The commenter states two of the three EPA documents supporting the proposed rule list the facility as having an emissions unit (*i.e.*, the furnace) that is in the "Container Glass" category rather than Flat Glass. The commenter explains that this error implies that the facility has a "Container Glass" furnace – even though the Plant is classified as a Flat Glass manufacturing facility.

Response:

The EPA has made corrections to docket filings to categorize the Sedalia Plant as a "Flat Glass" plant instead of a "Container glass" plant.

5.3.4.2 Emission Limits

<u>Flexibility</u>

Comment:

Commenter (0321) responds to the EPA's request for comments on whether non-EGU sources would run controls that would be installed as a result of the proposed rule on a year-round basis. With respect to flat glass furnaces, Commenter (0321) anticipates that control equipment would be operated as necessary to achieve applicable emissions limits, but that operational flexibility, cost considerations and equipment longevity would warrant operation of 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). Additionally, flexibility in the operation of control equipment when unnecessary to meet emissions limits will better allow for routine maintenance and repairs without requiring variances or similar exemptions from continuous operation requirements to conduct such maintenance. Accordingly, emissions control equipment used to meet the emissions limits in the proposed rule should not be required to be operated on a continuous or year-round basis.

Response:

As explained in Section VI.C of the preamble, the EPA is finalizing requirements for non-EGUs that will apply only during the ozone season (which runs annually from May-September). As discussed in the proposed rule, this is consistent with the 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. Thus, the final rule does not require that emissions control equipment used to meet the emissions limits in the final rule be operated on a year-round basis.

Comment:

Commenter (0321) states that the glass and glass product manufacturing industry should not be included in a trading program. According to the commenter, the emissions trading program in the proposed rule is applicable only to EGUs, and the commenter opposes the imposition of any emissions trading program on industrial non-EGU sources to the extent it would impose additional cost and complexity on them.

Response:

Thank you for the comment. The EPA is not including the glass and glass product manufacturing industry in the trading program in the final rule.

Comment:

Commenter (0377) notes the proposed rule states that "EPA is not proposing to include non-EGUs in the trading program described in this proposed rule" because unit-specific limits are "more administratively feasible and more easily implementable at the source level" given the monitoring requirements associated with an emissions trading program. However, that rationale does not account for the fact that an emissions trading program represents an important opportunity to lower compliance costs for all sectors subject to the proposed rule. Given the EPA's proposed $7,500 per ton threshold for determining applicable NO_X limits, unit-specific controls could cost millions of dollars and involve significant capital outlays. Commenter's (0377) members have successfully participated in emissions trading programs as a compliance mechanism for other state and federal air pollution control requirements, and such programs provide an important alternative option where unit-specific compliance might require unreasonably costly control options. Commenter (0377) therefore recommends that the EPA provide the opportunity for non-EGU sources to work with regulators to develop an emissions trading program prior to the proposed 2026 compliance deadline as a complementary compliance mechanism to mitigate such costs.

Response:

The EPA responds to these comments in Section VI.C of the preamble to the final rule. The EPA has concluded that a unit-specific emissions limit approach is more appropriate at this time for non-EGUs than implementing a trading program and requiring units to implement rigorous part 75 monitoring and reporting requirements.

Comment:

Commenter (0758) states the glass and glass product manufacturing units are projected to emit 12,059 tons of Ozone season emissions in 2023. NO_X emissions from these units contribute greater than or equal to 0.01 ppb to 11 different downwind receptors, with glass manufacturers in at least seven states contributing greater than or equal to 0.01 ppb]. This makes glass and glass product manufacturers the fourth largest non-EGU industrial contributor to NO_X emissions under the proposed rule and an important source of emissions to control for limiting interstate transport of NO_X emissions. Moreover, the EPA projects that the glass and glass product manufacturing subsector holds the third-highest potential for ozone-season NO_X emissions reductions among the various non-EGU subsectors covered by the proposal, only slightly surpassed by the cement and concrete product manufacturing subcategory. Commenter (0758) notes that the glass and glass product manufacturing subsector's NO_X emissions are not currently subject to NSPS, and that the industry is expected to grow in the coming years.

Response:

The EPA appreciates the commenter's support of the EPA's action to regulate NO_X emissions from the glass and glass product manufacturing industry.

Comment:

Commenter (0758) supports the EPA's effort to regulate this important source of NO_X emissions, which must be reduced to ensure that upwind states are eliminating their significant contributions to downwind ozone pollution problems.

Response:

The EPA appreciates the commenter's support of the EPA action to regulate NO_X emissions from the glass and glass product manufacturing industry.

Comment:

Commenter (0758) notes while the proposed limits on glass furnaces fall within the ranges of limits required by various states and air districts, the proposed limits are set at the weakest levels within those ranges. 87 Fed. Reg. at 20,147, tbl. VII.C-4. For example, the EPA proposes to set a limit of 4.0 lb NO_X/ton of glass for Container Glass Manufacturing Furnaces even though state and local requirements range much lower, from 1 to 4 lb/ton. Id. The same leniency is present in the proposed emissions limit of 4.0 lb/ton for Pressed/Blown Glass Manufacturing Furnaces, while state and local emissions limits range from 1.36-4 lb/ton, and 9.2 lb/ton for Flat Glass Manufacturing Furnaces, while states range from 5-9.2 lb/ton. Id. It is worth adding, the EPA partly bases its proposed NO_X emissions limit for flat glass manufacturing furnaces on the San Joaquin Valley air district's RACT rules; however, the 9.2 lb/ton limit in those rules is a daily rate. The San Joaquin Valley air district's rolling 30-day average rate, which is more comparable to the form of emissions limit that the EPA has proposed here, is lower: 7 lb/ton. The EPA should therefore lower the emissions limit for flat glass manufacturing furnaces in the final rule, at least to a rate that reflects this underlying local precedent. With all of these ranges, the EPA notes that the upper end could be reduced significantly through post-combustion control. Id. Given that some states and air districts—many of which are contending with ozone nonattainment problems that are exacerbated by upwind NO_X emissions—already require glass manufacturing furnaces to meet emissions limits well below those proposed by the EPA, the EPA must finalize lower emissions limits for these furnaces.

Response:

For flat glass manufacturing furnaces, the EPA had proposed a NOx 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 NOx 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[85] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule.

Comment:

Commenter (0758) adds the EPA should consider requiring units to phase out and retire if they can be cost-effectively replaced by more energy efficient and less emitting units, like all-electric melter installations. Section 110(a)(2)(D)(i)(I) commands the states and the EPA to "prohibit any source . . . within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State." 42 U.S.C. § 7410(a)(2)(D)(i)(I) (emphasis added). Nothing in this language suggests that the plan must allow sources that are significantly contributing to downwind pollution problems to continue to operate. The possibility of replacing units with all-electric or other lesser emitting units should be considered similarly to any other emissions control and required where cost-effective.

Response:

EPA is not establishing any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time.

30-Operating Day Rolling Average

Comment:

Commenters (0321, 0406, 0548) note the proposed text in 40 CFR 52.44(d)(2) inconsistently references the use of a 30-operating day rolling average. However, even when the "operating day" term is used, it is not defined. If the rule were to stipulate that for glass furnaces an "operating day" is a day, or portion of a day, when glass is produced, and that therefore the NO_X limit does not apply to periods of start-up, shutdown and idling, then the issue noted here could potentially be resolved. Commenter (0548) notes the proposed rule is unclear regarding how 30-day rolling averages are calculated. Commenter (0548) recommends any future rulemaking clarify that the limits are connected to an operating 30-day average, and not daily emissions limits as outlined.

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[85] For example, Pennsylvania's RACT NOx emission limits for flat glass furnaces are 7.0 lbs of NOx 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*.

Response:

The final rule establishes emissions limits for affected units in the Glass and Glass Product Manufacturing industry that apply on a 30-operating day rolling average basis. We explain the basis for the 30-operating day averaging period in Section 5 of the Final Non-EGU Sectors TSD. The final rule defines “operating day” to mean “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 §§ 52.44(d), 52.44(e), and 55.44(f), as applicable.” Thus, periods of startup, shutdown, or idling may be excluded from the calculation of an affected unit’s emissions over a 30-operating day rolling average period only if, for startup and shutdown, the affected unit complies with the alternate work practice standards established in the final rule for these periods and, for idling, the affected unit complies with the alternative emissions limits applicable under the final rule during these periods. Additionally, the final rule contains a detailed definition of “rolling average” that explains how to calculate an emissions level on a 30-operating day rolling average basis for purposes of demonstrating compliance with the emissions limits in the final rule.

Comment:

Commenter (0321) notes the preamble explains that: “Owners or operators of affected units must calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period.” Id. at 20147. However, despite this preamble language, use of a 30-operating day rolling average is not clearly stated in the proposed rule.

Response:

In this final rule, the EPA is revising Testing and Monitoring requirements outlined under § 52.44(g) to require owners or operators of affected units to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass pulled during the annual performance test. The use of 30-day rolling average for the glass product manufacturing is consistent with other federally approved RACT NO_X regulations for this sector. In this final rule, 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:

Commenter (0321) states the provisions in the proposed regulations for facilities using CEMS does not appear to implement a 30-operating day rolling average. See 40 C.F.R. § 52.44(d)(2). In contrast, for facilities without CEMS, proposed § 52.44(d)(1) clearly indicates that compliance is to be measured on the basis of a 30-day operating period, and provides instructions for calculating compliance when measuring compliance via performance testing.

Id. at § 52.44(d)(1)(A)-(D). Presumably the emissions rate calculated by the performance test is then to be applied for all production over a 30-operating day period, although that approach would provide a total of NO_X emissions over that 30-operating day period but would not result (or have the potential to result) in any different NO_X emissions rate, since the NO_X emissions rate is derived from the performance test itself. In this context, application of a 30-operating day rolling average would appear to be inconsequential to measuring compliance.

Response:

In this final rule, the EPA finalizing compliance assurance requirements that allow affected glass manufacturing furnace to demonstrate compliance through annual testing and parametric monitoring or the use of CEMS data in lieu of performance tests. Under § 52.44(g), owners or operators of affected units will be required to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test.

Comment:

Commenter (0321) states the calculation for facilities with CEMS, where implementation of a 30-operating day rolling average is both useful and possible, is not clearly stated in the proposed regulations. The rule requires that facilities with CEMS must, on a daily basis, divide the average pounds of NO_X emitted per day by the tons of glass removed per day, and then compare that rate to the limits in § 52.44(c). Id. at § 52.44(d)(2); 87 Fed. Reg. 20147. There is no clarification or definition of how the “average” pounds of NO_X per day (in Step 1 of the calculation) or the tons of glass removed per day (Step 2) are to be derived. As a result, the calculation methodology established in § 52.44(d)(2) imposes what appears to be a daily limit rather than clearly allowing compliance to be measured on the basis of a 30-operating day rolling average.

Response:

In this final rule, the EPA is finalizing compliance assurance and Testing and Monitoring requirements that assure that the emissions requirements implemented for glass and glass product manufacturing are connected to an operating 30-day average. Owners or operators of applicable glass manufacturing furnace may demonstrate compliance through annual testing and parametric monitoring or the use of CEMS data in lieu of performance tests. Affected glass melting furnaces subject to the final rule that employ NO_X CEMS may use CEMS data in conformance with 40 CFR 60, Appendix B.[86]

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[86] 40 CFR 60, Appendix B, Performance Specification 2- Specifications and Test Procedures for SO2 and NOx Continuous Emission Monitoring Systems in Stationary Sources. See

Comment:

Commenter (0321) concludes it may be that the first sentence of proposed § 52.44(d)(1) is intended to apply to both the situations where NO_X emissions are determined via a performance test and where they are measured via a CEMS. If so, that sentence should be set forth separately, and not as a component of only the calculations for facilities without CEMS. In any case, the provisions in § 52.44(d)(2) regarding monitoring of compliance via a CEMS should be revised to specifically provide that the daily emissions rates are to be averaged over a 30-operating day period, and then that emissions rate is to be compared to the limits in § 52.44(c).

Response:

In this final rule, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnace to demonstrate compliance through annual testing and parametric monitoring or the use of CEMS data in lieu of performance tests. Under § 52.44(g), owners or operators of affected units will be required to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrated through CEMS data in lieu of annual performance test.

Comment:

Commenter (0758) states although some states and air districts also utilize a 30-day average, others include a 24-hr average emissions limit. For example, the San Joaquin Valley air district has adopted NO_X emissions limits based on both 30-day rolling and daily averages, with the daily averages slightly less stringent than the 30-day rolling average limits. Including a daily average alongside a 30-day rolling average is preferable to ensure that units continue to run and maintain their controls throughout the ozone season. Indeed, for the reasons discussed in the section on the backstop daily emissions limits for EGUs, a daily limit is legally required to ensure that sources within a state are eliminating their significant contributions to downwind pollution within a timeframe relevant to the 8-hr ozone NAAQS. Establishing daily limits is similarly important within this industrial subsector because the EPA is basing its glass and glass products manufacturing limits primarily on the installation and use of SCR, which is a post- combustion control that might be turned off when not needed to meet an emissions limit. A daily emissions limit would help prevent unnecessary idling of emissions controls and is needed to ensure that a unit does not continue to contribute to downwind nonattainment or maintenance issues.

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https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/appendix-Appendix%20B%20to%20Part%2060.

Commenter (0758) suggests one possibility that the EPA should consider is keeping the proposed limits, which are lenient, but make them daily limits instead of 30-day averages while adding an additional, more protective 30-day average limit. This approach, as well as the daily limits themselves, would reflect the NO_X limits that the San Joaquin Valley air district has established. The higher daily limit would give sources additional flexibility on a day-to-day basis to account for variations in the unit's activity or problems that might arise with emissions controls, while still ensuring that units effectively utilize their controls to meet daily and 30-day limits.

Response:

During the development of the proposed emissions standards, the EPA reviewed various RACT NO_X rules, air permits, Alternative Control Techniques (ACT), and consent decrees to determine the appropriate NO_X emissions limits for the different types of glass manufacturing furnaces. During the EPA's review of the industry, it was apparent that significant differences between glass furnace designs, configurations, age, fuel capabilities, furnace type, and differences in raw material compositions currently exist throughout 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 NOx 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 NOx 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[87] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule. We explain the basis for the 30-operating day averaging period in Section 5 of the Final Non-EGU Sectors TSD.

Although some glass manufacturing furnaces may already be controlled by RACT rules and other regulatory programs, some of which may be more stringent than the requirements the EPA is establishing in this final rule, it is important to note that many of the sources subject to this final rule are located in states that have not implemented RACT requirements since RACT is only applicable to sources located within ozone nonattainment areas and within the OTR. Also, as noted within the preamble and in Section 5 of the Final Non-EGU Sectors TSD, many OTR states have adopted RACT regulations for the glass manufacturing sector that do not themselves establish the required NOx limits but instead require a case-by-case evaluation. The emissions limits in this final rule require all affected units to install and operate cost-effective controls that are widely in use, and thus bring all affected units up to a uniform level of control

[87] For example, Pennsylvania's RACT NOx emission limits for flat glass furnaces are 7.0 lbs of NOx 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*.

stringency as necessary to eliminate significant contribution to downwind nonattainment and maintenance receptors.

Startup, Shutdown, and Idling Emissions

Comment:

Commenters (0321, 0397, 0406, 0418, 0584) state it is important to recognize that during startup, shutdown and idling glass furnace temperatures are much lower than they are during normal operating conditions. Lower exhaust temperatures make it technologically infeasible to operate furnaces equipped with Selective Catalytic Reduction (SCR) since there is a greater risk of forming ammonium bisulfates when temperatures are lower, which will damage the equipment. Since the control equipment cannot be operated during start-up, shutdown and idling without damaging the equipment, it will be very difficult or impossible to meet the proposed NO_X limits during these times. To the extent the regulations provide for a rolling average period for measuring compliance with the NO_X emissions limits, use of a rolling average does not remedy this issue, since start-ups can last for 3- 4 weeks, shutdowns for 1-2 weeks, and periods of idling can last for more than 4 weeks.

Response:

As stated elsewhere in this document and preamble, the EPA will finalize flexibility provisions to provide affected owners and operators of applicable glass manufacturing furnace alternative work practices during periods of start-up, shutdown, and idling. The EPA has modeled the alternative standards that apply during startup, shutdown, and idling conditions on State RACT alternative requirements identified by commenters.[88]In this final rule, the EPA has provided definitions of “startup”, “shutdown”, “idling”, and “operating day” for glass manufacturing furnaces in § 52.44(a). Owners or operators of an affected unit are subject to the NO_X emissions limits outlined in § 52.44(c), on a 30-operating day rolling average beginning with the 2026 ozone season and in each ozone season thereafter. 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.

Comment:

Commenters (0321, 0406) continue, establishing NO_X limits based on an amount of NO_X as measured against the amount of glass produced is an unworkable formula in the context of flat glass furnaces during start-up, shutdown and idling. The proposed NO_X limits are set in terms

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[88] Title 25, Part I, Subpart C, Article III, Sections 129.305-129.307 of PA’s NOx RACT regulation outlines alternative emission standards for Glass Manufacturing Furnaces during start-up, shutdown, and Idling. *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.

of pounds of NO_X per ton of glass produced. However, no glass is produced when a flat glass furnace is starting up, shutting down, or idling. As such, during these times, the concept of measuring NO_X emissions in terms of glass produced is infeasible and effectively imposes a zero emissions limit for NO_X during start-up, shutdown and idling.

Response:

As stated elsewhere in this document and preamble, the EPA is finalizing alternative emissions standards for applicable glass manufacturing furnaces 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.

Comment:

Commenters (0397, 0406) add during periods when glass pull is not occurring or when the glass pull rate is low, fuel must continue to be fired to ensure that the molten glass does not solidify. These periods would result in a high calculated lb/ton emissions rate even though actual mass emissions from the furnace are not elevated. The EPA should revise the limits in the proposed regulation to not consider days with low glass pull, such as abnormally low production rate days, furnace start up days, furnace maintenance days, and malfunction days, as "operating days" and therefore exclude these days from the calculation of 30 operating day rolling average emissions. This approach would be consistent with at least one Global Consent Decree agreed upon by the EPA (*e.g.*, Case Action No. 2:10-CV-00121-TSZ) and would be consistent with Wisconsin's NO_X RACT requirements found in NR 428.22(d), which contain an alternative limitation (*i.e.*, use of combustion optimization requirements) for low production days.

Response:

As stated elsewhere in this document and preamble, the EPA is finalizing alternative emissions standards for applicable glass manufacturing furnaces 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.

Comment:

Commenters (0321, 0397, 0406, 0418, 0584) argue an exception should be added to § 52.44(c) to allow glass furnaces appropriate allowances for periods of start-up, shutdown and idling, such as by stipulating that "operating days" for purpose of a rolling average based on "operating days" includes only those days, or portions of a day, when glass is produced.

Response:

As stated elsewhere in this document and preamble, the EPA is finalizing alternative emissions standards for glass manufacturing furnaces during periods of start-up, shutdown, and idling.

The EPA has modeled the alternative standards that apply during startup, shutdown, and idling conditions on State RACT alternative requirements identified by commenters.[89]In this final rule, the EPA has provided definitions of "startup", "shutdown", "idling", and "operating day" for glass manufacturing furnaces in § 52.44(a). Owners or operators of an affected unit are subject to the NO_X emissions limits outlined in § 52.44(c), on a 30-opertating day rolling average beginning with the 2026 ozone season and in each ozone season thereafter. 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.

Comment:

Commenters (0418, 0584) provide the first rule upon which the EPA relies is San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces" (amended May 19, 2011). The EPA failed to consider Section 4.4 of this rule, which provides that the emissions limits expressed in pounds of NO_X per ton of glass produced shall not apply during periods of startup, shutdown, or idling, and Section 3 .17 of this rule, which defines "idling" as operation of a furnace at less than 25 percent of its permitted glass production capacity. The second rule upon which the EPA relies is N.J.A.C. 7:27-19.l0(a). The EPA failed to consider the fact that each glass melting furnace subject to this rule either is not equipped with a CEMS and instead is required only to demonstrate compliance with its NO_X emissions limits through infrequent performance testing conducted during periods when the furnace is operating at maximum production rate or is exempt from complying with the NO_X emissions limits during periods of abnormally low production rate, cold startup, or furnace stabilization. The third rule upon which the EPA relies is 25 Pa. Code § 129.304. The EPA failed to consider the effect of 25 Pa. Code § 129.303(a), which provides that the emissions limits 25 Pa. Code § 129.304 shall not apply during periods of startup, shutdown, or idling, and 25 Pa. Code § 121.1, which defines "idling" as operation of a furnace at less than 25 percent of its permitted glass production capacity.

Response:

In response to these comments and based on the EPA's assessment of current practices within the glass manufacturing industry, the EPA is establishing provisions for alternative work practice standards and emissions limits that may apply in lieu of the emission limits in § 52.44(c) for glass manufacturing furnaces during periods of start-up, shutdown, and idling. The emissions limits applicable to glass melting furnaces under § 52.44(c) do not apply during periods of start-up, shutdown, or idling if the owner or operator of the affected unit complies with the alternative requirements applicable during periods of start-up, shutdown, or idling

[89] Title 25, Part I, Subpart C, Article III, Sections 129.305-129.307 of PA's NOx RACT regulation outlines alternative emission standards for Glass Manufacturing Furnaces during start-up, shutdown, and Idling. *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.

under §§ 52.44(d) – (f). The EPA has modeled these alternative requirements for startup, shutdown, and idling periods to some extent on State RACT alternative requirements identified by commenters. More information and the EPA's rationale in developing the alternative work practice standards and alternative emission limits for glass manufacturing furnaces during start-up, shutdown, and idling are provided in Section VI.C of the preamble and section 5 of the Final Non-EGU Sectors TSD.

SCR and Glass Product Manufacturing

Comment:

Commenters (0321, 0505) respond to the EPA's request for comments on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize combustion modifications like low-NO_X burners and oxy-firing to add and operate a post-combustion control device like SNCR and SCR to further improve their NO_X removal efficiency. By way of response to this question, it is unnecessary, and it would be unhelpful, for the proposed rule to specify use of particular post-combustion control devices.

Response:

As explained in Section VI.C of the preamble, the final rule does not specifically require affected units in the Glass and Glass Product Manufacturing industry to install any particular type of control technology. Instead, the final rule contains emissions limits applicable to this industry that 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. The EPA's rationale supporting the emissions limits in the final rule for the glass industry is provided in Section VI.C of the preamble and section 5 of the Final Non-EGU Sectors TSD.

Comment:

Commenter's (0321) various flat glass furnaces have a variety of combustion and post-combustion controls. Each furnace is somewhat different in its design, operations and finished products produced. It is more appropriate for the EPA to establish an emissions limit in the proposed rule than it is for the EPA to specify use of a particular control technology. Commenter (0505) believes the EPA should evaluate whether the proposed emissions limits could be achieved without installing post-combustion controls.

Response:

As explained in Section VI.C of the preamble, the final rule does not specifically require affected units in the Glass and Glass Product Manufacturing industry to install any particular type of control technology. Instead, the final rule contains emissions limits applicable to this industry that 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. The EPA's rationale supporting the emissions limits in the final rule for the glass industry is provided in Section VI.C of the preamble and section 5 of the Final Non-EGU Sectors TSD.

Comment:

Commenter (0418) notes the proposed rule would require installation and operation of costly SCR systems for control of NO_X emissions from, each affected container glass manufacturing furnace, even at facilities where there are two or more affected furnaces and where the facility-wide NO_X emissions reductions that the EPA determined to be necessary to meet good neighbor requirements can be achieved by over-controlling one or more affected furnaces. The EPA unreasonably and arbitrarily declined to propose a rule that would allow for more cost-effective approaches to achieving the NO_X emissions reductions that the EPA determined to be necessary to meet good neighbor requirements by allowing intra-facility or area-wide emissions averaging.

Response:

As described in the TSD, the EPA identified and listed several control devices that are used in practice for the control of NO_X emissions from glass melting furnaces throughout the industry.[90] When developing 2008 CSAPR Update Non-EGU Final TSD, the EPA conducted a cost-effective analysis of the control measure devices available for glass manufacturing furnaces and found that oxy- firing could reduce NO_X emissions by 7,880 tons from flat glass manufacturers at a cost of $3,097/ton; 2,628 tons from container glass manufacturers at a cost of $7,481/ton; and 851 tons from pressed glass manufacturers at a cost of $6,356/ton, of which fall within the range of cost-effectiveness determined appropriate in this final rule.[91]

Comments:

Commenter (0758) disagrees with commenters (0321, 0418, 0505) because the EPA expects to achieve 6,667 tons of ozone season NO_X emissions reductions from the glass manufacturing industry (in 15 states), at average annual costs of $1,109 to $3,770 per ton depending on the state, with an average of $1,520 per ton in eastern states and $1,293 per ton in western states primarily through SCR technology. These NO_X emissions reductions will be achieved at an average cost of $1,516 per ton with some additional reductions through oxygen enriched air staging at an average cost of $764 per ton.

Commenter (0758) adds in addition to SCR technology, the EPA's proposal shows that the EPA has identified many effective controls for these sources through the years. The EPA has previously found that oxy- firing could reduce NO_X emissions by 7,880 tons from flat glass manufacturers at a cost of $3,097/ton; 2,628 tons from container glass manufacturers at a cost

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[90] See Proposed Non-EGU Sectors TSD at 48 - 55, EPA-HQ-OAR-2021-0668-0145.

[91] Final 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 Final TSD, Docket ID: EPA-HQ-OAR-2018-0225-0023. See https://www.regulations.gov/document/EPA-HQ-OAR-2018-0225-0023

of $7,481/ton; and 851 tons from pressed glass manufacturers at a cost of $6,356/ton—all below the EPA's proposed $7,500/ton cost threshold. This technology has an even higher NO_X reduction percentage, at 85 percent, than SCR, at 75 percent. Given the availability of additional cost-effective controls, the EPA should consider whether oxy-firing or other controls—potentially in combination—could produce much greater NO_X emissions reductions and air quality improvements and be implemented at glass manufacturing facilities sooner than 2026.

Response:

The EPA responds to comments on control installation timing needs in Section VI.A of the preamble to the final rule.

5.3.4.3 Monitoring, Recordkeeping, and Reporting

CEMS

Comment:

Commenter (0337) assumes the EPA proposing to require all affected glass manufacturing facilities to install and operate CEMS is in error, but in any event contends that CEMS are unnecessary for multiple reasons. First, glass manufacturing facilities are not included in the NO_X trading program. Therefore, the need to impose rigorous monitoring to ensure equivalency across sources is unnecessary. This is consistent with the fact that under the NO_X SIP Call program, the EPA allowed non-EGUs that were taken out of the trading program to remove their CEMS. See, 84 Fed. Reg. 8422, 8424 (March 8, 2019). Second, installation and operation of CEMS is expensive, and requires employment of technically skilled personnel to maintain and operate. The use of periodic stack testing to develop emissions factors is a standard approach to demonstrating compliance with a wide-range of emissions limits, is more than appropriate in this circumstance, and avoids the unnecessary costs and technical complications of a CEMS.

Response:

As explained in Section VI.C of the preamble, compliance with the emission limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. The final rule allows affected units that operate NOx CEMS meeting specified requirements to use CEMS data 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 parameter limits and indicator ranges, and to subsequently conduct annual NOx performance tests. The final rule requires owners or operators not operating CEMS to also monitor and record stack exhaust gas flow rate, hourly glass production rate, and stack exhaust gas 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 applicable NO_X emissions limits.

Comment:

Commenter (0397) states the proposed regulatory text at 40 C.F.R. § 52.44(d) states that glass plants "must conduct performance tests, on a semiannual basis." This seems overly burdensome and unnecessary for those units that have a CEMS installed. The EPA should clarify that if a CEMS is installed, only the required testing and calibration of the CEMS is necessary.

Response:

In this final rule, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnace to demonstrate compliance through annual testing or the use of CEMS data in lieu of performance test. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test.

Comment:

Commenter (0406) notes there are several inconsistencies between the information provided in the preamble to the proposed regulation and the proposed 40 CFR 52.44 relating to the Glass and Glass Product Manufacturing industry. For example, 87 FR 20147 states that the EPA is proposing that each owner or operator of an affected facility install and operate a CEMS for measurement of NO_X. However, the proposed 40 CFR 52.44(d) contains language that seems to indicate that owners or operators can chose to install a CEMS (40 CFR 52.44(d)(2)) or conduct semi-annual stack testing and use the results to demonstrate compliance (40 CFR 52.44(d)(1)). As another example, the preamble at 87 FR 20146 states that the averaging period of the NO_X emissions standard is to be a 30-day rolling average. However, the compliance demonstration method at 40 CFR 52.44(d)(2) only provides a methodology to calculate daily lb/ton emissions to be compared with the proposed NO_X emissions standard.

Response:

As a result of the comments received on the proposal, the EPA is revising the compliance assurance requirements to provide flexibility for owners or operators of applicable glass manufacturing furnaces to demonstrate compliance with the emissions standards outlined in § 52.44(c). In this final rule, The EPA is revising the emissions standards to allow owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1), to demonstrate compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test. The EPA also made attendant revisions to the Testing and Monitoring Requirements codified under §52.44(g) to assure that the emissions standards finalized for glass manufacturing furnaces are on a 30-operating day rolling average. Under § 52.44(g), Owners or operators of affected units must calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass pulled during the performance test. In this final rule, the EPA has provided definitions of “startup”, “shutdown”, “idling”, and “operating day” for glass manufacturing furnaces in § 52.44(a).

Comment:

Commenter (0758) believes monitoring emissions is critical to ensure that units operate within the required emissions limits. CEMS is a well-known technology that has been used in many different applications to reliably monitor emissions and ensure that a source is meeting legal requirements. Requiring CEMS for glass and glass product manufacturing sources will help ensure that they meet the requirements of the proposed rule and help alert sources to any emissions problems quickly so they can be remedied. Requiring CEMS will be especially important if, as it must, the EPA adds a daily emissions limit to the proposed 30-day emissions limit. CEMS will be useful for ensuring compliance with the 30-day limit.

Response:

With respect to the 30-day averaging period, the EPA reviewed various RACT NO_X rules, air permits, Alternative Control Techniques (ACT), and consent decrees to determine the appropriate NO_X emissions limits and associated averaging times to establish for the different types of glass manufacturing furnaces.. The EPA's rationale supporting the 30-day rolling averaging time in the final rule for the emissions limits applicable to the glass industry is provided in section 5 of the Final Non-EGU Sectors TSD.

As explained in Section VI.C of the preamble, the EPA is finalizing compliance assurance requirements that allow for compliance with the emission limits to be demonstrated through CEMS or via annual performance tests and continuous parametric monitoring. 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. The final rule allows affected units that operate NOx CEMS meeting specified requirements to use CEMS data 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 parameter limits and indicator ranges, and to subsequently conduct annual NOx performance tests. The final rule requires owners or operators not operating CEMS to also monitor and record stack exhaust gas flow rate, hourly glass production rate, and stack exhaust gas 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 applicable NO_X emissions limits.

Comment:

Commenter (0758) states the EPA's proposed alternative method for demonstrating compliance with a 30-day average limit—*i.e.*, adding up emissions from three hourly tests and dividing those emissions by the tons of glass pulled in those three hours, 87 Fed. Reg. at 20,185 (proposed 40 C.F.R. § 52.44(d)(1))— does not suffice because emissions rates in those three hours could be uncharacteristically low, and unrepresentative of emissions rates during the other 717 hours during each 30-day period.

Response:

As a result of the comments received on the proposal, the EPA is revising the compliance assurance requirements to provide flexibility for owners or operators of applicable glass manufacturing furnaces to demonstrate compliance with the emissions standards outlined in § 52.44(c). In this final rule, The EPA is revising the emissions standards to allow owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1), to demonstrate compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test. The EPA also made attendant revisions to the Testing and Monitoring Requirements codified under § 52.44(g) to assure that the emissions standards finalized for glass manufacturing furnaces are on a 30-operating day rolling average. Under § 52.44(g), Owners or operators of affected units must calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass pulled during the performance test. In this final rule, the EPA has provided definitions of "startup", "shutdown", "idling", and "operating day" for glass manufacturing furnaces in § 52.44(a).

Comment:

Commenter (0377) argues the recurring maintenance and calibration costs associated with a NO_X CEMS are significant. Based on commenter's (0377) members' experience operating a CEMS for more than ten years at multiple facilities, these routine costs can run approximately $50,000 or more per source with a CEMS system. Depending on what components break and require repair, a facility may incur up to an additional $40,000 per CEMS per year. This does not include the internal labor cost for two hours per day of electrical support, which is routinely required several times per week. Commenter (0377) believes it is not necessary or reasonable to impose these significant compliance costs given that the NO_X emissions rate from a glass or glass product manufacturing facility should not vary significantly during normal operations.

Response:

As a result of the comments received on the proposal, the EPA is revising the compliance assurance requirements to provide flexibility for owners or operators of applicable glass manufacturing furnaces to demonstrate compliance with the emissions standards outlined in § 52.44(c). In this final rule, the EPA is incorporating revisions to the compliance assurance requirements to allow affected glass manufacturing furnace to demonstrate compliance through annual testing or the use of CEMS data in lieu of performance test. Under the revised Testing and Monitoring under § 52.44(g), owners or operators of affected units will be required to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) already install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test.

Comment:

Commenter (0377) notes significant, ongoing resources are required to properly operate and maintain a CEMS, which can have the effect of diverting critical environmental and maintenance resources away from other critical environmental tasks. One example of this extraordinary demand on resources is specific to the oxygen sensors (both wet and dry) that are associated with a CEMS. These sensors, which are costly, routinely fail. Failure not only requires replacement but impacts CEMS calculations dependent on the oxygen sensor readings and commonly results in the system displaying artificial emissions rates that are not representative of operations. These common sensor failures require a facility to maintain a large spare parts inventory, which is becoming increasingly hard to achieve as parts / equipment shortages and long lead times are now part of normal operations.

Response:

As explained in Section VI.C of the preamble, compliance with the emission limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. The final rule allows affected units that operate NOx CEMS meeting specified requirements to use CEMS data 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 parameter limits and indicator ranges, and to subsequently conduct annual NOx performance tests. The final rule requires owners or operators not operating CEMS to also monitor and record stack exhaust gas flow rate, hourly glass production rate, and stack exhaust gas 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 applicable NO_X emissions limits.

Comment:

Commenter (0337) contends a semiannual frequency of testing is unnecessary and excessive. A company like Anchor Hocking that has multiple potential affected sources would incur hundreds of thousands of dollars a year in stack testing costs. There also are considerable logistical difficulties in securing qualified testing contractors. A testing frequency of twice per permit cycle (or once every 2.5 years), or even once per permit cycle is standard for general compliance demonstrations and would be suitable for demonstrating compliance with this emissions limit.

Response:

The EPA acknowledges the cost associated with the installation and maintenance of CEMS and the workload associated with the semi-annual testing to demonstrate compliance with the finalized emissions standards for the glass and glass product manufacturing sector. Therefore, the EPA is revising the compliance assurance requirements to provide flexibility to owners or operators of affected units. The EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnace to demonstrate compliance through annual testing or the use of CEMS data in lieu of performance test. To avoid challenges in scheduling and availability of testing firms, the annual performance test, intended to satisfy this particular requirement of the final rule, does not have to be performed during ozone season. Under the

Testing and Monitoring provisions under § 52.44(g), owners or operators of affected units will be required to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test.

Comment:

Commenter (0406) states the proposed text in 40 CFR 52.44(d) appears to require semi-annual stack testing for NO_X whether a CEMS is present or not. If CEMS are present, stack sampling requirements should be required as per the CEMS performance specification and quality assurance requirements in 40 CFR 60, or elsewhere.

Response:

As mentioned elsewhere in the document and the preamble, the EPA finalizing revisions to the compliance assurance requirements to allow affected glass manufacturing furnace to demonstrate compliance through annual testing or the use of CEMS data in lieu of performance test. The EPA are making these revisions in response to comments received on the proposal. Under the revised Testing and Monitoring under § 52.44(g), owners or operators of affected units will be required to calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) already install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test.

CEMS Alternatives

Comment:

Commenters (0321, 0377) argue periodic stack testing conducted under normal operating parameters can provide assurance regarding ongoing compliance with the proposed rule. Stack testing can be accomplished efficiently and at a reasonable cost when consolidated with testing to show compliance with applicable emissions limits for other air pollutants. In fact, a number of commenter's (0377) members' facilities subject to state or local NO_X emissions limits demonstrate compliance in exactly this manner, and a CEMS is not currently a common compliance assurance method for commenter's (0377) members' (potentially contrasting with other industries such as the electricity generation sector). Commenter (0321) states CEMS should not be required for the Glass and Glass Product Manufacturing Industry. Requiring a CEMS adds cost and complexity in a situation where emissions can be effectively monitored using stack testing rather than continuous monitoring. A float glass furnace is a continuous and stable operation, and there are multiple drivers and incentives, from safety to product quality, for furnace operators to ensure stable operations. As such, stack testing is representative of ongoing operations and is a sufficient and effective tool to measure compliance; mandatory use of CEMS is unnecessary.

Response:

As a result of the comments received on the proposal, the EPA is revising the proposed compliance assurance requirements to provide flexibility for owners or operators of applicable glass manufacturing furnaces to demonstrate compliance with the emissions standards outlined in § 52.44(c). In this final rule, the EPA is incorporating revisions to the compliance assurance requirements to allow affected glass manufacturing furnace to demonstrate compliance through annual testing or the use of CEMS data in lieu of performance test. In this final rule, the EPA is not mandating requirements for owners or operators of applicable glass manufacturing furnaces to install and operate CEMS. If owners or operators of a glass manufacturing plant subject to the NO_X emissions limits under § 52.44(c)(1) install and operate NO_X CEMS to monitor NO_X emissions, compliance with the 30-operating day rolling average NO_X emissions limits may be demonstrate through CEMS data in lieu of annual performance test. Owners or operators may also demonstrate compliance via an annual performance test and through continuous parametric monitoring.

Comment:

Commenter (0377) provides comment on whether "to require each owner or operator of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility." Periodic stack testing or a PEMS can provide an alternative monitoring approach that is significantly less costly than CEMS while still providing reasonable demonstration of facility compliance with NO_X emissions limits.

Response:

In this final rule, the EPA is finalizing Testing and Monitoring requirements under § 52.44(g). To provide flexibility for owner or operators applicable to the finalized emissions standards for Glass and Glass Product Manufacturing sources, compliance with the 30-operating day rolling average may be demonstrated through annual testing or the use of CEMS data in lieu of performance test.

Comment:

Commenter (0377) continues, in fact, the language of the proposed rule allows for the alternative of stack testing or a CEMS, citing CEMS requirements "[i]f a continuous monitoring system has been installed on the affected unit . . ." Commenter (0377) believes the semi-annual stack testing proposed in 52.44(d) is an unnecessary waste of resources that does not provide commensurate benefits unless a facility is near or above the proposed emissions limit. Therefore, in lieu of a CEMS or semi-annual testing, commenter (0377) proposes retaining the option of a CEMS or stack testing, but would recommend annual NO_X stack testing to validate the lb/hr NO_X emissions rates unless the affected unit tests above 75 percent of the NO_X emissions limit, at which point testing would revert to semi-annual until again below 75 percent of the emissions limit. At a minimum, commenter (0377) also believes that a facility should have the ability to use a PEMS. A PEMS 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. Both of these alternative approaches would be sufficient to ensure compliance with the proposed rule without imposing unreasonable and unnecessary compliance costs.

Response:

As explained in Section VI.C of the preamble, compliance with the emission limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. The final rule allows affected units that operate NOx CEMS meeting specified requirements to use CEMS data 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 parameter limits and indicator ranges, and to subsequently conduct annual NOx performance tests. The final rule requires owners or operators not operating CEMS to also monitor and record stack exhaust gas flow rate, hourly glass production rate, and stack exhaust gas 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 applicable NO_X emissions limits.

5.3.5 Boilers From Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, the Iron and Steel industry, and the Metal Ore Mining industry.

5.3.5.1 Applicability Threshold

Comments:

Commenter (0421) references Page 20083 of the April 6, 2022, Federal Register (FR) Notice, the EPA notes that the EPA focused on assessing emissions units that emit greater than 100 tpy of NO_X emissions. Furthermore, footnote 163 of the notice further clarifies that as part of the non-EGU emissions reduction assessment prepared for the Revised Cross State Air Pollution Rule that the EPA reviewed emissions units with greater than 150 tpy of NO_X emissions. The EPA then opted to broaden the scope to include emissions units with greater than or equal to 100 tpy of NO_X emissions. However, 40 CFR 52.45(b)(1) states that, "The requirements of this section apply to each new or existing boiler with a design capacity of 100 MMBtu/hr or greater fueled by coal, residual oil, distillate oil, or natural gas, located at sources that are within the Basic Chemical Manufacturing Industry (NAICS Code 3251xx), the Petroleum and Coal Products Manufacturing industry (NAICS code 3241xx), and the Pulp, Paper, and Paperboard industry (NAICS code 3221xx), and which is located within any of the states listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such state(s)."

Commenter (0421) continues, on Page 20148 of the FR Notice, the EPA notes that “we find that the 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.” The EPA further seeks comment on whether the EPA should alternatively set an applicability threshold based on a PTE. Our input is that the use of a heat input criteria alone unfairly subjects industrial boilers that have low NO_X emissions already to this rule. For example, commenter (0421) has several industrial boilers that meet or exceed the NO_X emissions limit 0.08 lbs/MMBTU NO_X that are operated with a heat input just above 100 MMBTU/hr. Please note that a boiler with a heat input of 100 MMBTU/hr that is emitting NO_X at 0.08 lbs/MMBTU is emitting 8 lbs/hr or a maximum of 35 tpy NO_X (if operating for all hours in a year).

Commenter (0421) believes, to address both of these applicability concerns, the EPA should adjust the applicability criteria to include a requirement that the annual NO_X emissions must also be greater than 100 tpy of NO_X before these new regulatory requirements apply. Again, this is important since the proposed rule, which is based on heat input alone, could include a number of boilers that are emitting well less than 100 tpy. In both cases, there will be minimal to no ozone air quality benefit to regulating these sources further under the proposed expanded Cross State Air Pollution Rule (CSAPR). Thus, commenter (0421) suggests the EPA incorporate into the final rule a requirement that the boiler must also either emit 100 tpy or greater of NO_X or have an enforceable annual emissions limit that is 100 tpy or greater.

Commenter (0421) suggests the following regulatory text for 40 CFR 52.45(b)(1):

The requirements of this section apply to each new or existing boiler with a design capacity of 100 MMBtu/hr or greater with a PTE of equal to or greater than 100 tons NO_X per year fueled by coal, residual oil, distillate oil, or natural gas, located at sources that are within the Basic Chemical Manufacturing Industry (NAICS Code 3251xx), the Petroleum and Coal Products Manufacturing industry (NAICS code 3241xx), and the Pulp, Paper, and Paperboard industry (NAICS code 3221xx), and which is located within any of the states listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such state(s).

Commenters (0362, 0421, 0437) request that the EPA adjust the applicability criteria to include a requirement that the annual NO_X emissions must also be greater than 100 tpy of NO_X; noting that it is possible that the proposed rule, as written (based on heat input alone), could subject a number of boilers that are emitting well less than 100 tpy. Commenter (0421) briefly discusses a few cases where this may occur and further requests that the EPA incorporate into the final rule a requirement that the boiler must also either emit 100 tpy or greater of NO_X or have an enforceable annual emissions limit that is 100 tpy or greater. Commenter (0421) agrees that it is not clear from the proposed regulatory language that the scope of the rule is limited as such. The commenters (0421, 0437) restate the proposed regulatory language at 40 CFR 52.45(b) and compare it to the language at 40 CFR 52.45(c).

Commenter (0437) requests that the EPA revise the applicability threshold from a heat input basis to an ozone season emissions basis for boilers in Tier 2 industries. The commenter questions, if ozone season NO_X emissions are the most important factor for applicability for boilers, why not set the threshold based on NO_X emissions as it was done for cement and concrete product manufacturing, glass and glass product manufacturing, and iron and steel mills and ferroalloy manufacturing? The commenter briefly discusses reasons why the boiler threshold may not approximate an emissions level of 100 tpy (*e.g.*, operating scheduled) and why boiler NO_X emissions might be limited (*e.g.*, seasonally operated boiler).

Commenter (0437) recommends that if the EPA concludes that an applicability threshold criterion based on heat input capacity is necessary (for boilers), the EPA should adopt a threshold of 250 MMBtu/hr, which is consistent with the NO_X SIP Call.

Commenters (0338, 0432) state that, as proposed, the rule would apply to new or existing boilers with a design capacity over 100 MMBtu/hr but the rule should apply to boilers with actual ozone emissions of 100 tons of NO_X per ozone season.

Commenters (0320, 0359) contend the EPA is proposing to apply ozone-season NO_X emissions limits that are more stringent than NSPS limits to all fossil fuel-fired boilers in certain industries that are greater than or equal to 100 MMBtu/hr in capacity, regardless of actual emissions and the feasibility or cost effectiveness of add-on NO_X controls.

Response:

As the commenters note, the EPA did use 100 tons per year of actual emissions as applicability criteria for some of the non-EGU sectors in the proposal. However, we chose to propose different applicability criteria for boilers that is based on boiler design capacity because doing so eases applicability determinations given that a boiler's design capacity, in most cases, is clearly indicated by the manufacturer on the unit's nameplate. Additionally, all of the state RACT rules we reviewed and cited within our proposal, and the EPA's own prior regulatory efforts regarding boilers[92] also rely on boiler design capacity as applicability criteria. As explained within the Proposed Non-EGU Sectors TSD, most boilers sized 100mmBTU/hr or greater fueled by coal, residual or distillate oil, or natural gas have the PTE 100 tpy or more, and we are maintaining these criteria in this final FIP rulemaking. Using applicability criteria of 250 MMBtu/hr or greater would exclude boilers that could potentially emit more than 100 tpy and thus would not be consistent with the regulatory requirements for the non-EGU sectors that used 100 tpy as applicability criteria.

The EPA acknowledges that using 100 MMBtu/hr of heat input as part of the applicability criteria will result in some units with emissions of less than 100 tpy being covered by the FIP's requirements. Although the individual contribution from any one boiler to downwind nonattainment or maintenance receptors may be insignificant, collectively boilers rated at this size threshold or higher in the states and industries covered by this final rule have substantial NO_X emissions which do cause or contribute to downwind air quality problems. However, in light of comments received on our proposal, the EPA has considered the request to provide an exemption for infrequently run units given the low level of emissions they produce and agree that such an exemption is appropriate. A summary of comments received requesting a limited

[92] See, for example, the NSPS requirements for boilers found at 40 CFR 60, subpart Db.

use exemption and the EPA's response is provided elsewhere in this section of this RTC document.

Comments:

A number of commenters asserted that a low use exemption for infrequently run units should be provided in the final rule due to the lower amount of emissions they produce.

Commenter (0437) requests that the EPA revise the applicability language at proposed 40 CFR 52.45 to exclude limited-use boilers and temporary boilers, assuming the EPA applies ozone season emissions limits to industrial boilers in the final rule. The commenter briefly describes a few reasons why these boilers should be excluded – *e.g.*, these units only operate for a limited amount of time each year, their overall contribution to total NO_X emissions is small.

Commenter (0362) urges the EPA to promulgate a limited- use subcategory of boilers for each source category of Tier 1 or Tier 2 boilers proposed for regulation for any boiler that burns any amount of solid, liquid, or gaseous fuel and has a federally enforceable average annual capacity factor of no more than ten percent (10 percent). The commenter believes that the justification/rationale used by for the limited-use subcategory in Boiler MACT applies here [40 C.F.R. 63, subpart DDDDD].

Commenter (0338) states that the EPA should exclude limited-use or temporary boilers from the rule. The commenter argues that NO_X emissions from these units are limited and because these boilers spend much or their time in startup, shutdown or low load conditions, the effectiveness of NO_X controls is questionable. In addition, the commenter states that due to the limited amount of emissions, controls would not be cost effective and would exceed $7,500/ton.

Response:

The EPA has considered the request to provide an exemption for infrequently run units given the lower level of emissions they produce and agrees that such an exemption is appropriate. The amount of air pollution emitted from a boiler is directly related to the amount of time it operates, and a diminished benefit occurs from controlling emissions from infrequently run units. Therefore, the final rule allows a facility owner to submit a request for a low use exemption that restricts the boiler from operating more than 10 percent of the year based on hours of use. If the EPA grants the request, the boiler will be excluded from the final FIP's requirements for as long as it operates 10 percent or less on a calendar year basis.

Comment:

Commenter (0437) requests that the EPA clarify that the proposed standards are not intended to apply to pulp and paper recovery furnaces (sometimes referred to as recovery boilers); arguing that the industry has only limited, short-term experience with NO_X control technology, the impact on other pollutants such as sulfur dioxide, carbon mono$_x$ide and reduced sulfur compounds is unknown, and some furnaces cannot accommodate quaternary air ports due to their physical dimensions.

Response:

The EPA's final requirements for non-EGU boilers do not extend to equipment such as pulp and paper recovery furnaces or recovery boilers.

Comment:

Commenter (0437) supports the EPA's conclusion to exclude boilers in the wood product sector from the proposed rule, because NO_X emissions from boilers at wood product mills do not contribute to any downwind receptors and are more than two orders of magnitude below the criteria for inclusion.

Response:

The EPA's final requirements for non-EGU boilers apply to boilers in the wood product sector if they combust, on a heat-input basis, 90 percent or more of coal, residual or distillate oil, or natural gas, or combinations of these fuels. The EPA's response to comments regarding our analysis of the impacts of contributions from sources located in upwind states on downwind receptors is contained within Section 2.2 (Methods Used to Identify Impactful Industries and Potential Emissions Units in the Non-EGU Screening Assessment).

Comment:

Commenter (0422) submits that any final rule should exempt boilers that are constructed to and meet the requirements in the NSPS Rule 40 CFR part 60 subpart Db. As an alternative, the commenter offers that the EPA should consider the option of deeming boilers compliant to the proposed rule if they meet the NSPS standard. According to the commenter, this will avoid a new additional regulatory requirement for boilers that are already controlling their emissions. The commenter relates that new boilers constructed to meet the NSPS standard would likely not be able to meet the new proposed standard without additional controls. The commenter also relates that in the last five years, it has invested over $50 million dollars on new natural-gas boilers, which has yielded a 40 percent and an 87 percent NO_X reduction from fuel combustion at two of its manufacturing facilities. According to the commenter, an additional $5-$8-million-dollar investment would be needed for all its boilers that comply with NSPS Db to meet the proposed emissions limit if burner replacement is a viable option, noting that existing boilers may not be able to be retrofitted and would need to be replaced. The commenter asserts that the current cost/benefit analysis does not include the cost of a complete boiler replacement.

Response:

These comments are responded to in Section VI.C.5 of the preamble. In addition, the preamble identifies the types of controls and estimated costs of those controls for boilers in Section V.C.2. For boilers, the EPA anticipates that boilers will be able to meet the final emissions limits by installing SCR or low-NO_X burners and FGR. While a facility could make a business decision to replace a boiler rather than retrofitting it, the EPA anticipates that the final emissions limits will not require the replacement of any boilers.

Boiler Fuels

Comments:

Commenter (0437) states that the EPA should clarify that the Tier 2 boiler standards only apply to large industrial boilers firing exclusively fossil fuels. The commenter states that the EPA only contemplated and assessed emissions and impacts from controlling boilers firing exclusively coal, oil, or gas, and selected its proposed emissions limits based on RACT rules for single fuel- fired boilers, it is not clear from the proposed regulatory language that the scope of the rule is limited to such.

Commenter (0328) recommends that the EPA review its definitions and clarify natural gas fired units, specifically at steel/ferroalloy facilities where some boilers use a combination of natural gas and coke oven gas in their operations. Commenter (0328) recommends that the EPA consider proposing a specific standard for coke oven gas or provide definitions that address coke oven gas and natural gas fuel fired combinations to clarify what is a coke oven gas fired boiler and what is a natural gas fired boiler.

Commenter (0432) requests that definitions and applicability for boilers be clarified in the rule. According to the commenter, the proposed rule language and preamble do not adequately define several terms and the applicability of the proposed rule to various industrial boilers, including those that combust a fossil-fuel as a back-up fuel, multi-fuel boilers, and recovery, biomass, and limited use boilers. The commenter notes that the EPA has not explicitly proposed to establish ozone season NO_X emissions limits for pulp and paper biomass or recovery boilers and they believe it was not the EPA' s intent to do so; however, the commenter's biomass and recovery boilers start up on and may co-fire No. 2 fuel oil, and it is not clear to the commenter whether boilers that start up on or co-fire a fossil fuel would be subject to ozone season NO_X emissions limits. The commenter notes that the EPA proposed to PTE to determine non-EGU applicability; however, PTE is not defined in the proposed FIP. The commenter also states that applicability should be based on emissions during ozone season, not annual PTE.

Commenter (0432) states emissions reductions that the EPA proposes to require for uncontrolled boilers will force the mill to implement costly and stringent control technologies that have not been applied in the pulp and paper industry (*e.g.*, SCR). The EPA’s Screening Assessment indicates that a 90 percent NO_X reduction could be achieved from one of our boilers for an annual cost of $1.2 million and a cost effectiveness of $7,187/ton; however, it is not our industry's experience that applying SCR is either reasonable or cost effective.

Commenters (0300, 0324, 0329, 0336, 0359, 0421, 0505, 0557) state the proposed FIP does not address the combustion of fossil fuel mixtures (such as natural gas and oil) or the combustion of fossil fuels, particularly natural gas, with biomass, landfill gas, or process gases generated on site (*e.g.*, hydrogen or refinery fuel gas). The proposed emissions limitations for Tier 2 non-EGU boilers do not contemplate the use of various types of fuels, including biomass and landfill gas, or the design of the boiler. The proposed emissions standards for Tier 2 non-EGU boilers only include four standards based on the “unit type,” which was assumed to be one of the following four single fuel uses: coal, residual oil, distillate oil, and natural gas. In comparison, the National Emission Standards for Hazardous Air Pollutants (NESHAP) for

Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources addresses 15 categories of boilers (78 FR 7142; January 31, 2013).

Commenter (0300) argues combustion of what would otherwise be waste, including but not limited to biomass, landfill gas, tire-derived fuels, and used oil, is essential for energy recovery and reducing waste streams to our landfills wastes that would otherwise ultimately result in the release of decomposition gases such as carbon dioxide and methane (*i.e.*, greenhouse gases). Boilers have proven to be a reliable method for recovering energy from what would otherwise be a waste and are also used for control of process gases generated on-site that also have available heat value. These boilers are also already regulated by NSPS under section 111(b) of the CAA, including NSPS subparts D, Da, Db, and Dc; and the NESHAP under section 112(d) of the CAA, including NESHAP subparts DDDDD and JJJJJJ. These federal standards consider the combustion of biomass, and the NSPS subparts already address NO_X emissions. Finally, other federal standards allow for use of boilers to control (*i.e.*, combust) process gas streams with high VOC, HAP, and sulfur compound concentrations. Given the complete lack of consideration for boilers burning fuel mixes and/or fuels not contemplated by the proposed FIP, the EPA should forego regulating industrial boilers under the FIP.

Commenter (0336) recaps the proposed rule requirements for industrial boilers, citing the following [40 CFR 52.45(b)]:

> (b)(1) The requirements of this section apply to each new or existing boiler with a design capacity of 100 mmBtu/hr or greater fueled by coal, residual oil, distillate oil, or natural gas, located at sources that are within the…..
>
> At 40 CFR 52.469(c), the proposed limitations for industrial boilers are as follows:
>
> (c) Emission Limitations. Beginning with the 2026 ozone season and in each ozone season thereafter, the following emissions limits apply, based on a 30-day averaging time:
> 1. Coal-fired industrial boilers: 0.20 lbs NO_X/MMBtu
> 2. Residual oil-fired industrial boilers: 0.15 lbs NO_X/MMBtu
> 3. Distillate oil-fired industrial boilers: 0.12 lbs NO_X/MMBtu
> 4. Natural gas-fired industrial boilers: 0.08 lbs NO_X/MMBtu

Commenter (0336) argues that the regulation does not provide specifications for boilers that use multiple fossil fuels, for example those that fire coal and natural gas. Commenter questions, “How should emissions standards in such instances be calculated”? The regulation also does not provide limitations for boilers that burn other types of fuel, such as biomass, either by itself or in conjunction with fossil fuels. Commenter believes that the EPA should clarify how these types of units show compliance with the regulation and what limitations apply to units that burn fossil fuels in conjunction with other fuels.

In regard to biomass boilers, commenter (0437) believes it was the EPA’s intent to exclude biomass boilers from this rule and asks the EPA to make that intent clear if pulp and paper boiler requirements are finalized. The commenter notes that NO_X control technologies are not identified for these boilers in the EPA’s CoST model and maintains that these technologies are not widely applied to biomass boilers in their industry. The commenter further notes that in the

EPA's Transport Proposal – Tier 2 Boiler Analysis – 03-16-2022.xlsx Excel workbook, none of the boilers have biomass boiler SCCs.

Commenter (0362) requests that the EPA exclude boilers that have the capability to co-fire fuels from being subject to any emissions limits in any final ozone transport FIP that the EPA may promulgate.

Commenter (0329) suggests that the EPA clarify, or include, the applicable emissions limit(s) for other combustion sources identified in the proposed Plan that may also burn biomass or other liquid/gaseous waste in addition to, or in combination with, coal, oil, or natural gas.

Commenter (0338) states that the rule is unclear as to how it applies to boilers that use multiple fossil fuels and suggests that the EPA could follow the approach taken in the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR part 60, subpart Dc) to provide this necessary clarity. The commenter notes that this rule requires the boiler operator to calculate the applicable emissions limit based on a ratio of each fuel fired to the overall heat input of the unit. The commenter states that this allows operators to maintain flexibility to use multiple fuel types, while showing compliance with applicable limits.

Commenter (0362) objects to the expansion of this proposed rule to any boiler combusting alone or in combination a fuel for which an emissions limit has not been proposed. The commenter argues that inclusion of these units would thereby deprive them of the opportunity to consider and comment on whatever emissions limits the EPA may adopt, as guaranteed by the US Constitution, and required by the APA and the CAA.

Commenter (0324) argues the EPA should provide clarification as to what NO_X emissions rate applies to certain types and operation of fossil fuel boilers. Specifically, for coal boilers that fire natural gas and/or biomass either concurrently or sequentially, it is unclear in the rule whether the coal-based limit or other limit(s) applies.

Commenter (0421) argues boilers that are operated with gas fuels other than natural gas or that are mixed with natural gas should not be subject to this rule. Alternatively, the commenter states that the EPA must propose a different and higher emissions limit than 0.08 lbs NO_X/MMBtu and allow for impacted industry to comment on a different limit.

Commenter (0343) points out that more than half of the boilers at pulp, paper and paperboard mills combust more than one fuel. According to the commenter, in the pulp and paper industry, cofired or combination (fossil fuel and biomass) boilers that are equipped with ESPs or fabric filters are characterized by flue gas temperatures exiting these control devices that are much lower than those commonly found in coal utility units or even 100 percent fossil fuel-fired industrial units (300ºF to 400ºF vs greater than450ºF) and that higher temperatures than what is found in pulp and paper industry boilers are needed for SCR system to function properly. The commenter notes that besides this technical fact that is critical for effective SCR operation, the application of SCR and SNCR for NO_X control becomes very difficult for most pulp mill co-fired units when these units are designed to be "load-carrying," resulting from the process steam demand fluctuating for various unavoidable reasons, such as product demand and process unit(s) being offline. The commenter continues, noting that the pressure drop requirements associated with a SCR system can render existing boiler fans unsuitable and create sizing concerns in existing, especially older, boilers. The commenter further notes other concerns about the use of SCR systems, including that there could be plugging and fouling of the catalyst due to large amounts of fly ash preceding an electrostatic precipitator (ESP) or fabric filter, primary $PM_{2.5}$ emissions could increase due to formation of sub-micron particulates of NH4SO4, and inadequate gas temperatures may also lead to significant amounts of unreacted ammonia (slip) being released that result in the formation of condensable PM.

Commenter (0545) asserts that the EPA should provide an exemption for any boiler with 5 percent or more biomass in its fuel composition and should provide an exclusion for shutdowns and annual maintenance. The commenter believes it would be very difficult to set a standard for these boilers due to variability in boiler design and variability inherent to biomass fuels and their associated nitrogen content. Given this uncertainty, the commenter urges the EPA to consider an exemption for any boiler with 5 percent or more biomass in its fuel consumption. The commenter also notes that some facility control systems, such as SCR, may require an annual shutdown for a few days for preventive maintenance while the furnace continues to operate. The commenter urges the EPA to exclude annual maintenance shutdowns from required compliance with the proposed NO_X emissions limitation of 9.2 lbs/ton in the draft FIP.

Commenters (0300, 0437) observe that 40 CFR 52.45(b) does not address combustion of a mixture of the four listed fuels (*i.e.*, coal, residual oil, distillate oil, or natural gas) or those fuels with other fuels (*e.g.*, biomass, used oil, process gases, etc.). Commenter (0437) declares that if the EPA finalizes the proposed requirements for industrial boilers, the Agency should make it clear that the boiler standards apply only to certain industrial boilers with allowable NO_X emissions of 100 tons or greater during ozone season firing exclusively fossil fuels, and not to units such as recovery furnaces, heat recovery steam generators, gas turbines, and biomass-fired boilers. Commenter (0437) recommends that the EPA adopt the following definitions (relating to boilers) at 40 CFR 52.45:

Industrial 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 feed rates are controlled. Waste heat boilers as defined at § 63.7575, chemical recovery boilers, commercial and residential boilers, refining kettles, ethylene cracking furnaces, and blast furnaces are not included in this definition.

Biomass includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal- water mixtures. Coal derived gases are excluded from this definition.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have 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); or (4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8. Process gas, landfill gas, coal derived gas, refinery gas, biogas, and blast furnace gas are not included in this definition.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about what types of fuel combustion are covered by the EPA's final NO_X requirements for non-EGU boilers.

Comment:

Commenter (0343) remarks that for base-loaded fossil fuel-fired units, SCR operation is only feasible if there is room to place an SCR unit downstream of the PM control device and cost effectiveness estimates are reasonable. Additionally, the commenter says that size constraints and the lack of piping runs and other real-estate can often make retrofitting an SCR system near the boiler impossible.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about infeasibility of installing controls.

Comment:

Commenter (0329) argues this Plan will not achieve emissions reductions as modeled unless the EPA includes emissions limits for industrial boilers that combust biomass (*e.g.*, wood,

wood waste, etc.) or other liquid/gaseous byproducts/waste generated at the facilities identified by the EPA.

Response:

The EPA analyzed the emissions reductions we expected to obtain as provided for by the non-EGU screening assessment developed to support our proposal and compared them to the reductions we anticipate will be achieved from the NO_X emissions limits for non-EGU boilers we are adopting in this final rule and determined that they are approximately equal. The non-EGU screening assessment developed to support our proposal included reductions from some large boilers that were primarily powered by fuels other than coal, residual or distillate oil, or natural gas, and such units will not be covered by this final rule. However, the shortfall in emissions reductions this creates is compensated by the final rule's applicability criteria for boilers which extends to a greater number of emissions units than we analyzed in the non-EGU screening assessment developed to support our proposal.

Comments:

Commenter (0362, 0437) supports an exemption for cogeneration units meeting the criteria described at 87 Fed. Reg. 20087, noting that these units should not be subject to any emissions reduction requirements under this rulemaking. The commenter relays that cogeneration units provide environmental benefits by offsetting fuel combustion and emissions that would otherwise be necessary to produce electricity. The commenter asserts that the final regulatory language should define cogeneration units and make the exemption clear. The commenter asserts that the EPA should continue to exclude boilers in the wood product sector. According to the commenter, the EPA found that NO_X emissions from boilers at wood product mills (NAISC 3212 Veneer, Plywood, and Engineered Wood Product Manufacturing) do not contribute to any downwind receptors and are more than two orders of magnitude below the criteria for inclusion. The commenter supports the conclusion to exclude these boilers and sector. The commenter also asserted that the EPA must address multi-fueled boilers. The commenter remarks that the proposed regulatory language does not address how the limits might apply to situations where multiple fuels are fired simultaneously or where multiple fuels are fired during a 30-day period. To clearly address boilers that co-fire fossil fuels or fire more than one type of fossil fuel and to remove any confusion over what emissions limit applies, the commenter recommends that the EPA adopt a method similar to those found in the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR part 60, subpart Db) and the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR part 60, subpart Dc). According to the commenter, emissions limits in these NSPS rules vary by the fuel fired (and the configuration of the boiler), and if a boiler simultaneously combusts a mixture of fossil fuels, the applicable NSPS emissions limit is calculated based on the ratio of each fuel fired to the overall heat input of the unit. The commenter recommends that the EPA incorporate a similar limit calculation methodology in the final rule to allow operators to maintain the flexibility to fire multiple and varying fossil fuel types while still demonstrating compliance with the NO_X limits on a 30-day rolling average basis. For clarity, the commenter suggests that definitions of 30-day average and boiler operating day, consistent with the language in NSPS subpart Db, be added to the final rule. The commenter also recommends that the EPA make it clear in the final rule that boilers burning more than 10 percent biomass are not covered by any emissions limit and that the EPA should also allow facilities burning byproduct/waste with gas or oil to petition for an alternate NO_X emissions limit. The commenter explains that some pulp and paper mill boilers are used to burn process off-gases to comply with other air regulations, which can increase NO_X emissions due to their ammonia content, and thus need to be treated differently.

Commenter (0362) recommends that the EPA include the following suggested definitions:

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.

Cogeneration unit means a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, through sequential use of energy.

Response:

These comments are responded to in Section VI.C.5 of the preamble.

Comment:

Commenter (0324) asserts that the EPA's statement that "*establishing emissions limits for emissions units based on size and type of unit and, in some cases, emissions thresholds, will achieve the necessary reductions without requiring a unit-by-unit assessment*" could be problematic because the types of controls required for the non-EGU sources usually do require a unit-level analysis to justify and account for site-specific factors. For example, unlike EGUs, for industrial boilers these factors could include the technological feasibility of controls due to unit size and space constraints, operating parameters such as flue gas temperature which would require reheat for SCR operation, and absorbents used to treat flue gas for HCl to address MACT requirements which are incompatible with SCR technology. The operational schedule of units which may primarily operate outside of ozone season is another consideration.

Response:

The EPA understands that a unit-by-unit assessment is likely needed to determine which types of NO_X control technology are compatible with a particular type of equipment and to determine which compatible controls will enable the unit to meet the applicable NO_X emissions limit. It was the EPA's intent, within the text extract mentioned by the commenter, to articulate that the emissions limits we proposed should be achievable by the emissions units covered by our proposed applicability criteria. Therefore, a unit-by-unit analysis to determine appropriate emissions limits would not be needed.

Comment:

Commenter (0505) states if the EPA expands the scope of the regulated fuels, the EPA should clarify whether boilers and industrial furnaces that are regulated as existing facilities by 40 CFR part 266, subpart H would be exempt.

Response:

The EPA has not expanded the scope of the boiler fuels regulated by this final rule beyond what was proposed. A boiler burning hazardous waste located in a state covered by the non-EGU requirements of this final FIP within one of the affected non-EGU industries is not subject to the requirements for boilers of this final rule unless it burns 90 percent or more of coal, residual or distillate oil, or natural gas, on a heat-input basis.

Comment:

Commenter (0324) recommends the EPA to define boilers fueled by coal, boilers fueled by gas, and boilers fueled by other fuels including oil and biomass. Defining the boilers will help ascertain which emissions limitation(s) may apply to boilers that fire multiple fuels. In particular, since there are no limitations proposed for biomass fueled boilers, the EPA should provide criteria, such as a threshold for percentage of heat input provided by biomass, for which a boiler would have no limitations based on this rule and how the rule will apply to mixed fuel boilers that do not meet this threshold.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about what types of fuel combustion are covered by the EPA's final NO_X requirements for non-EGU boilers.

Comment:

Commenter (0557) argues if fuel type usage changes from year to year, applicability provisions should address this contingency.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about what types of fuel combustion are covered by the EPA's final NO_X requirements for non-EGU boilers. The final rule's emissions limits for boilers are designed in a flexible manner such that if the fuels or fuel combinations used by the boiler change, the required emissions limit will also change based on the heat-input supplied by each fuel.

From Basic Chemical Manufacturing

Inadequate Technical Analysis

Comment:

Commenter (0243) notes that the EPA states in the preamble of the rule that non-EGU Boilers that emit 100 tpy of NO_X emissions were used to determine the impact on downwind receptors of NO_X emissions from Large Boilers in the Basic Chemical Manufacturing sector. In the proposed rule, the EPA did not take into consideration that there are Boilers with a design heat capacity of 100 MM BTU/hr or more that are operated on a limited bases and therefore will emit far less than 100 TPY NO_X emissions. For example, commenter (0243) operates two natural gas fired boilers that have a design heat capacity of more than 100 MM BTU/hr each and that are used to provide back-up steam when the primary source is down for maintenance. This happens infrequently and emissions from these backup boilers are very small.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about limited use boilers.

Comment:

Commenter (0761) urges the EPA to reconsider expanding the scope of the rule as proposed for chemical manufacturing sector boilers based on concerns with the adequacy and accuracy of the underlying technical analysis, the feasibility of many proposed requirements, and the timeline to implement them.

Response:

The EPA has considered comments received on our proposal and incorporated modifications into the final rule that have improved the accuracy and feasibility of the final rule's requirements, and also provided compliance options in cases where a facility may need additional time to implement the final rule's requirements.

NAICS Clarification

Comments:

Commenter (0243) states to allow low emitting boilers to operate during times of service outage, commenter (0243) recommends that the EPA include an exemption for natural gas fired boilers with low emissions which is based on a limit on hours or days of operation which will effectively reduce actual emissions.

Commenter (0243) proposes the following language which would limit operation to one fourth of a year in operating hours/days:

"Non-EGU Boilers that burn natural gas and operate 90 days/2160 hours a year or less are exempt from the requirements of this regulation. To demonstrate the boiler meets this exemption, the owner/operator must either maintain records of the days or hours of operation for the boiler or have a federally enforceable permit limitation on the days or hours of operation. In addition, records to show that natural gas is the fuel used must be maintained unless there is a federally enforceable limit in a permit that specifies natural gas is the only fuel that is used."

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about what types of fuel combustion are covered by the EPA's final NO_X requirements for non-EGU boilers and the limited use exemption provided in the final rule.

Comment:

Commenter (0417) believes to understand, plan, and comply with significant regulations such as the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, industry requires certainty – and the proposed regulatory language falls short.

Moreover, clarity is required to avoid an uneven playing field if the regulation is not uniformly applied. The lack of clarity has been raised by other commenters in the docket, such as the Ohio EPA, which noticed that it "finds it difficult to determine our subject sources based on the applicability criteria provided in the proposed rule." EPA-HQ-OAR-2021-0668-0266.

Response:

The EPA disagrees that the proposed regulatory language was unclear but has modified the final rule's applicability criteria for boilers within Section 52.45(b) of this final rule based on comments received on the proposal to clarify the requirements.

Comment:

Commenter (0417) argues, based on a thorough review of the preamble and the supporting documentation in the docket, commenter's (0417) boilers are not subject to the proposed FIP. To determine how the EPA characterized its facility and its boilers, Tata reviewed the rule preamble, the Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 ("Non-EGU Screening Assessment") (EPA-HQ-OAR-2021-0668-0150) and the Transport Proposal – Tier 2 Boiler Analysis 0 03-16-2022; All NAICS Units – 2023 Industry Identification Analysis (Attachment) (EPA- HQ-OAR-2021-0668-0225). In this documentation, the EPA appropriately identifies commenter's (0417) facility (Green River Works) under the NAICS Code 212391 and the 4-digit NAICS Code 2123 (Nonmetallic Mineral Mining and Quarrying) and therefore not subject to the proposed FIP. Commenter's (0417) conclusion is supported by the EPA's statements that there are no facilities in Wyoming with boilers greater than100 tpy NO_X emissions. (87 Fed. Reg. 20,084 at fn 170; Non-EGU Screening Assessment at 6, fn 18.)

Response:

Although the EPA's proposal extended to facilities located in Wyoming, the final rule does not contain requirements for facilities located there. As discussed further in Section III of the preamble, we are deferring final action at this time on the proposed FIPs for Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action.

Pulp, Paper, and Paperboard Mills

Affected Facilities Clarification

Comment:

Commenter (0338) comments that the proposed rule should specify that a biomass boiler is any boiler that uses five percent or more biomass in its fuel composition and such boilers should be specifically exempted from the rule.

Response:

See Section VI.C.5 of the preamble of this final rule for an explanation of the applicability criteria and exemptions provided for boilers.

Comment:

Commenter 0432 notes that it already implements good combustion practices and is required under the Boiler MACT to conduct periodic tune-ups on its fossil-fueled boilers to reduce NO_X emissions.

Response:

The commenter does not indicate the rate of NO_X emissions its boilers achieve by controlling emissions with the periodic tune-ups required by Boiler MACT requirements. If the commenter's boilers are able to meet the NO_X emissions limits of this final action with just periodic tune-ups, no further emissions controls are required; if they are not unable to do so, then the facility must install whatever additional controls are needed to comply with the boiler requirements of this final rule, or submit and receive EPA approval of a request for a case-by-case limit.

5.3.5.2 Emission Limits

Case-By-Case Assessment

Comment:

Commenter (0324) notes that the EPA is establishing emissions limits based on size and type of unit and, in some cases, emissions thresholds, and the EPA is also proposing to allow a daily mass cap at cement plants, but not among affected units at a facility for other source categories. The commenter states that the rule should allow a pathway for a source to determine if the control assumed is technically/economically infeasible, noting that these types of controls usually do require a unit-level analysis to justify and account for site-specific factors. According to the commenter, for industrial boilers, unlike EGUs, these factors could include unit size and space constraints, operating parameters like flue gas temperature, absorbents used to treat flue gas for HCl, and the operational schedule of units, which may primarily operate outside of ozone season.

Response:

The EPA agrees that there may be instances where a NO_X emissions limit for a coal, residual or distillate oil, or natural gas-fired boiler may be infeasible due to a demonstrated technical impossibility of installing the required controls or due to extreme economic hardship, and has provided within Section 52.40(e) of the final rule a provision allowing such sources to submit documentation to the EPA describing the circumstances preventing the emissions unit from meeting the required emissions limit. Such sources may request an alternative emissions limit.

Cost Estimates

Comment:

Commenter (0324) finds there are potential issues with the EPA's cost assessment. According to the commenter, one potential issue, related to the site-specific factors is the EPA appears to base its control costs for industrial boilers on EGU cost estimates from the EPA's COST, which is not designed to be used for unit-specific, detailed engineering analyses. The commenter remarks that another potential issue is that the cost assessments in the proposed rule are annualized, whereas the emissions reductions and associated modeling impact are based on ozone season emissions. According to the commenter, applying the controls and costs on an ozone season only basis may increase the costs significantly, especially for those units that operate primarily outside of the ozone season. The commenter asserts that the EPA should state how these issues were addressed in its cost assessment or reevaluate its cost assessment to address these issues.

Response:

These comments are responded to in Section 2.2 (Non-EGU Industry Screening Methodology).

The EPA disagrees that the controls and costs should be considered on an ozone-season basis. The analyses for EGU costs are also presented as annual costs, facilitating comparison between the EGU and non-EGU control strategies and their uniform control stringencies and relative cost/ton values.

Inventory Data

Comment:

Commenters (0320, 0359) argue that the EPA's analysis is not based on a quality inventory based on the 2017 NEI.

Response:

The EPA based its analysis on data derived from the National Emissions Inventory (NEI), a comprehensive database of criteria and hazardous air pollutant emissions from stationary and mobile sources that is based upon data provided by State, Local, and Tribal agencies, and supplemented by data from the EPA. We note that the EPA and the jurisdictions that submit information to the NEI do so in accordance with rigorous quality assurance and quality control procedures as outlined within the 2017 NEI Plan and related documents such as the Emissions Inventory System (EIS) Automated QA Checks for the 2017 NEI Spreadsheet.[93] Additionally, in accordance with the provisions of 40 CFR part 51, Appendix A, major stationary sources of emissions such as pulp and paper mills report their actual emissions, not allowable emissions, to these agencies which in turn submit this information to the EPA. Therefore, we reject the assertion that industry was not provided an opportunity to review the 2017 version of the NEI when in fact they were the original source of portions of this information. The commenter alleges that some states report allowable rather than actual emissions to the NEI but does not name any such state, and as noted above the federal air emissions reporting requirements of part 51, Appendix A clearly require that actual emissions be reported. Various commenters

[93] The two items referenced in this sentence are available at: https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data#doc

provided the EPA with corrections and updates to the emissions inventories. We have incorporated updates that were found to be credible into the emissions inventories used to support this final FIP action. In addition, the data used for the non-EGU analyses for the analytic year were based on the 2019 NEI that contains more updated information on facility configurations than the 2017 NEI. The EPA incorporated the results of a review of permit information for NO_X point sources and incorporated the results of that analysis into the existing control information in the inventory prior to it being used in the non-EGU analyses.

SCR

Comment:

Commenter (0320) states the application of SCR reduces NO_X emissions but comes with disbenefits. The environmental and energy impacts associated with SCR include the transport, handling, and use of aqueous ammonia, a corrosive hazardous material. Ammonia poses a potential exposure health and safety risk. The spent catalyst from the SCR would be required to be periodically replaced and disposed of properly, creating residual waste that would need to be landfilled or otherwise disposed. SCR systems have adverse air impacts due to the energy penalty and associated additional fossil fuel combustion, ammonia slip, possible formation of a visible plume, oxidation of carbon monoxide to carbon dioxide, and oxidation of SO_2 to sulfur trioxide with subsequent formation of sulfuric acid mist due to ambient or stack moisture.

Response:

The EPA acknowledges that risks exist with the transport, handling, use, and storage of ammonia, but notes that these risks are minimized by federal and state regulatory requirements that govern these activities. Additionally, we note that ammonia is a widely used commodity that is used safely by many industries across the U.S. and in many other countries.

Comment:

Commenter (0320) concludes, given the high cost of controls, the associated adverse impacts of SCR, other NO_X control measures on the books and on the way (*e.g.,* the mobile source reduction strategies discussed at 87 Fed. Reg. 20087), and the uncertainty of whether application of costly controls will achieve the desired downwind impact, the EPA should defer application of NO_X controls to industrial boilers until it determines they are actually necessary to achieve downwind attainment.

Response:

As described within the Non-EGU Screening Assessment memorandum developed to support our proposed rule, we determined that NO_X reductions from non-EGU sources including industrial boilers were needed to help mitigate the impact of air pollution transport on downwind locations. Additionally, we believe that many of the industrial boilers covered by this final rule will be able to meet the emissions limits with combustion controls, which are less expensive to install and operate than SCR NO_X control systems.

Comment:

Commenter (0359) argues costs provided in the screening assessment for SCR average $11,200 per ozone season ton of NO_X reduced, far exceeding the threshold the EPA identified for non-

EGUs controls. The EPA failed to identify cost effective controls for the arbitrary and capricious proposed emissions limit; therefore, this source category should be excluded from the scope of this rule.

Response:

The commenter claims that the EPA's proposed emissions limits are arbitrary and capricious but does not provide support for this claim. We disagree with the commenter's statement that the emissions limits we proposed and are adopting within this final action are arbitrary and capricious, given the rationale we provided for them in our proposed and final rulemaking notices and related support documents. Regarding the commenter's assertion that the EPA provided a "cost threshold" within the non-EGU screening assessment, the EPA notes that it did not establish a cost threshold above which controls would not be required, but rather put forth an average cost of controls for the non-EGU sector. As with any average, some values are greater and some are less than that value.

Comments:

Commenter (0758) states the EPA estimates potential ozone season NO_X emissions reductions of 3,305 tons from pulp, paper, and paperboard mills (in 8 states), at an average cost of $3,243-$7,019/ton; 1,698 tons from basic chemical manufacturing (in 2 states), at an average cost of $3,939-$5,113/ton; and 1,030 tons from petroleum and coal products manufacturing (in 4 states), at an average cost of $2,349-$3,498/ton. The EPA expects to achieve these NO_X emissions reductions primarily through the installation/implementation of ultra-low NO_X burners and SCR technology. Screening Assessment Tbl 6. The EPA also proposes the following emissions limits for boilers in the Tier 1 or 2 industries:

Coal- 0.20 lb/mmBtu

Residual oil- 0.20 lb/mmBtu

Distillate oil- 0.12 lb/mmBtu

Natural gas- 0.08 lb/mmBtu

Commenter (0758) continues, however, 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. The limits for distillate oil and gas boilers in particular are lower than the lowest limits that the EPA even considered in developing the proposal. Moreover, 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. And, continuous emissions monitoring data available through the EPA's air markets program shows:

1. Coal-fired boilers achieve average NO_X emissions rates of 0.1153 lb NO_X / MMBtu with selective non-catalytic control technology (Ingredion Incorporated Argo Plant, Illinois), and 0.1162 lb/MMBtu using low NO_X burner technology with overfire air (Axiall Corporation Natrium Plant, West Virginia).

2. Gas-fired boilers achieve average NO_X emissions rates of 0.0058 lb NO_X / MMBtu (Johnsonville, Tennessee). More than half of the gas-fired boilers included in the air markets program data already emit NO_X at rates below the proposed rate.

3. Residual oil-fired boilers achieve average NO_X emissions rates of 0.0716 lb NO_X/MMBtu (Ravenswood Steam Plant, New York).

Commenter (0758) argues for gas, the RBLC Clearinghouse shows much more stringent limits are achievable. Many facilities are required to meet a NO_X limit of less than 0.0400 lb/mmBtu—less than half of the EPA's proposed limit. In addition to low NO_X burners, ultra-low NO_X burners, and SCR control technology, which several of the listed facilities have installed, the OTC also identified boiler tuning and optimization as an additional control method. The EPA should lower its proposed emissions limits for boilers, and consider whether certain control methods such as boiler tuning and optimization could be implemented earlier than 2026.The limit should apply on a 24- hour average, and CEMS must be required.

Response:

See Section VI.C.5 of the preamble of this final rule for an explanation and rationale for the emissions limits for boilers the EPA is adopting in this final rule.

Comments:

Commenter (0758) believes the EPA should require boilers to comply with a NO_X limit on a daily basis rather than on a 30-day rolling average. Many boilers are already subject to more stringent limits on a shorter averaging period, even hourly.

Commenter (0437) requests, regarding a proposed equation for calculating the applicable emissions limit, that definitions of *30-day average* and *boiler operating day* be consistent with the language in NSPS subpart Db.

Response:

We considered the commenter's request to require compliance with the emissions limits for boilers on a daily basis but are retaining the 30-day averaging period for boilers subject to the provisions of this final rule. The 30-day averaging period is to be based on 30 operating days on a rolling basis. This averaging timeframe is consistent with the EPA's NSPS for Industrial, Commercial, and Institutional steam generating units found at 40 CFR part 60, subpart Db. Furthermore, an air agency may choose to require an averaging period shorter than a 30-operating day rolling average in air permit(s) issued to facilities with boilers subject to this final rule's requirements. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production.

Comment:

Commenter (0359) states West Virginia's large industrial fossil fuel fired boilers greater than or equal to 250 mmBtu/hr that are subject to the NO_X SIP Call requirements were converted to natural gas with low NO_X burners. The proposed applicability for this proposal is fossil fuel fired boilers greater than or equal to 100 mmBtu/hr. Commenter (0359) requests the EPA consider compliance with the more stringent program to satisfy compliance requirements of both programs, rather than having duplicative requirements for the sources and the states.

Response:

To the extent an emissions unit is subject to emissions limits from other federal rules in addition to the requirements of this final rule, the facility must comply with the most stringent limit, and additionally must comply with other provisions such as testing, monitoring, reporting, and recordkeeping requirements of each rule unless otherwise noted in this or in other applicable federal requirements.

From Basic Chemical Manufacturing

Fuel Mixtures

Comments:

Commenter (0421) notes on Page 20149, the EPA notes that the majority of boilers covered by this section of the FIP proposal will combust one of the fuels for which the EPA has proposed emissions limits (coal, residual oil, distillate oil, or natural gas). However, the EPA requests comment on whether emissions limits for other types of fuels should be included in a final FIP, and if so, the types of fuels and the emissions limits that boilers powered by these fuels should be required to meet. Commenter (0421) understands the EPA's proposed rule specifically limiting applicability to new or existing boilers that are fueled by coal, residual oil, distillate, or natural gas all of the time. However, the EPA's proposed rule fails to provide any clarification on how boilers that are fueled by mixtures of gas streams are to be managed. The EPA should not finalize an emissions limit of 0.08 lbs NO_X/MMBTU (40 CFR 52.45(c)(4) for boilers combusting mixtures of gas fuels. If the EPA decides to include and regulate boilers combusting mixed fuel streams in the future, the EPA should carefully review NO_X emissions information and propose a higher emissions limit than 0.08 lbs/MMBTU. Then, the EPA should allow for the impacted industry to comment on a different limit. A couple of examples of mixed fuel streams in the chemical industry are provided below.

Example #1 – A boiler burns natural gas and a hydrogen/methane off-gas fuel from the plant fuel gas system or perhaps a hydrogen gas mixture from an on-site production process. Due to the presence of hydrogen in this off-gas, and subsequent higher combustion temperatures the NO_X emissions rate is between 0.06 to 0.12 lbs NO_X/MMBTU. It is critically important that highly integrated chemical production facilities be able to combust these off-gas streams to recover the heating value in terms of energy recovery (steam generation).

Example #2 – A boiler burns natural gas and also burns one or multiple vent gas stream from different processes as on-site, and thus acts as an emissions control device for those vent gas streams. Depending on the composition and flow of the vent gas streams, the NO_X emissions rate may exceed 0.08 lbs NO_X/MMBTU. Similar to example #1, it is very important that integrated chemical production facilities be able to route vent gas streams to on-site boilers to adequately control the vent gas streams and to recover energy in the form of steam.

Example #3 – A boiler burns hazardous waste and is subject to 40 CFR 63 subpart EEE for hazardous waste combustion. The boiler uses natural gas to start-up and stabilize operations, and then a mixture of natural gas, plant off-gas, and liquid waste is burned in the boiler.

Combustion of these materials generates different NO_X and other emissions versus combustion of natural gas. This case demonstrates that the EPA should not regulate the NO_X emissions associated with fuels mixed with natural gas combustion.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to questions about what types of fuel combustion are covered by the EPA's final NO_X requirements for non-EGU boilers.

Pulp, Paper, and Paperboard Mills

Air Quality Improvements

Comment:

Commenter (0437) believes that even if the reductions the EPA predicts for pulp and paper mill boilers were feasible, the air quality improvements the EPA anticipates at individual receptors are immeasurable by current ambient air quality monitoring systems. According to the commenter, the EPA's assessment shows that the maximum improvement at any receptor from controls on all Tier 2 boilers (in all proposed source categories) is 0.169 ppb, the maximum estimated improvement at any receptor from controls on 25 pulp and paper boilers is listed as 0.0117 ppb, and the average total improvement across all receptors from a single pulp and paper boiler is 0.0103 ppb. The commenter remarks that the current ambient air quality monitoring systems have a detection limit of approximately 0.3 ppb, which is more than an order of magnitude greater than the EPA's maximum estimated improvement from controlling pulp and paper boilers. The commenter states that if the EPA finalizes the rule as proposed, the pulp and paper industry would be required to spend from $30 million to almost $100 million per year for results that are too insignificant to even measure. Therefore, the commenter asserts that there is no quantifiable downwind benefit to controlling pulp and paper mill boilers, requiring controls on boilers is not necessary to achieve attainment in any downwind state, and these requirements should clearly be recognized as over-control.

Response:

We respond to comments about the EPA's analytical framework for identifying potentially impactful non-EGU industries, evaluating potential emissions reductions from these industries, and evaluating related control costs in Section 2.2 (Non-EGU Industry Screening Methodology). We respond to comments about potential overcontrol in Section 1.9 (Overcontrol claims) and Section V.D.4 of the preamble.

Emissions Limits Basis

Comment:

Commenter (0320) suggests that if the EPA revises its analysis and determines that Tier 2 industrial boilers should be subject to NO_X emissions limits in the final rule, the EPA should incorporate regulatory language that allows for the application and approval of case-by-case

RACT emissions limits. According to the commenter, case-by-case RACT emissions limits are necessary when sources cannot meet the prescribed emissions limits cost-effectively or due to the unique technical limitations specific to a particular source. The commenter notes that precedent for allowing case-by-case RACT analyses and emissions limits is well established and is included in several of the rules the EPA used as the basis of the proposed standards. The commenter also points out that NSPS subpart Db allows operators to petition the Administrator for facility-specific NO_X emissions limits.

Response:

The EPA has included provisions within the final rule allowing sources to submit a request to the EPA Administrator for an alternative emissions limit based on technical impossibility or extreme economic hardship.

SCR and SNCR

Comments:

Commenter (0320) states most industrial coal-fired boilers will likely need additional controls to meet the EPA's proposed ozone season NO_X emissions limitations. Although this rule does not specifically require the use of any particular control technology, the commenter states that the emissions reductions the EPA proposes for industrial boilers will force facilities with uncontrolled boilers to attempt to implement the most stringent control technologies, which have not typically been applied in industry.

Commenter (0320) notes that two Westvaco coal-fired boilers already use LNB and overfired air to reduce NO_X emissions and that the effectiveness of SNCR on the two Westvaco coal-fired boilers is unknown but would likely be on the low end of the range because they experience variable loads. The commenter also relays that the two coal-fired boilers at the commenter's Granger facility use overfired air. The commenter states that the only way their boilers would be able to reliably comply with the EPA's proposed ozone-season NO_X limit would be to install an SCR. The commenter argues that the EPA did not provide any additional detail on how the proposed limits were derived from the limits identified in the state rules. The commenter adds 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 states that based on a review of the available data in the RBLC and given the technical difficulties and low control efficiency CE 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.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to this question.

Comment:

Some types of boilers may need to install flue gas reheat systems to achieve operating temperatures high enough for SCR operation, which increase both capital and operating costs.

(WPC)

Response:

See Section VI.C.5 of the preamble to the final rule for a response to this question.

Comments:

Commenter (0343) states 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. The commenter notes that in a SNCR system, the region of the boiler where the optimal temperature range for the reduction reactions to successfully complete is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. The commenter remarks that modeling studies in some FPI boilers have indicated that there are no locations within the boilers with high enough temperature for SNCR to be technically feasible. According to the commenter, another factor preventing proper implementation of SNCR technology in load-following boilers is inadequate reagent dispersion in the injection region due to inherent boiler design, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.*, large ammonia slip). The commenter notes 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. The commenter adds that SNCR has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads.

Commenter (0343) states that to NCASI's knowledge, there exists no evidence of long-term full-scale SCR or SNCR systems installed and currently operating full time on kraft recovery furnaces anywhere in the world. The commenter also states the use of SCR on a kraft recovery furnace has never been demonstrated, even on a short-term basis. The commenter states that since the recovery furnace is a chemical reactor and the heart of the cooking and recovery liquor cycle in a kraft mill, no mill is going to risk their liquor cycle being unduly affected by the SNCR NO_X control system where ammonia would be injected in the furnace before the ash (saltcake) is removed in the ESPs and returned to the saltcake mix tank. The commenter adds that an SCR system would entail a severe energy penalty that by itself has been shown to be economically inviable. The commenter continues by stating that there are several untested technical issues surrounding the injection of urea or ammonia within a kraft recovery furnace for NO_X control over a long-term basis. The commenter remarks that it is not known whether the long-term injection of NO_X reducing chemicals within the furnace could have negative effects on the kraft liquor chemical cycle, and long-term tests would need to be conducted to address this issue. In addition, the commenter states that other factors, such as the impact of large variations in flue gas temperatures at the superheater entrance due to fluctuating liquor firing rates, limited residence times for the NO_X-NH3 reactions available in smaller furnaces, impact on fireside deposit buildup due to reduced chloride purging from long-term NH3/urea use and the resulting impact on tube corrosion and fouling, potential for significant NH3 slip and plume opacity problems due to NH4Cl emissions, etc., need to be investigated thoroughly.

Further, the commenter states that the impact of high PM concentrations in the economizer region and fine dust particles on catalyst effectiveness is a major concern as is catalyst poisoning by soluble alkali metals (Na, K) in the gas stream. The commenter adds that in the case of SCRs installed after the electrostatic precipitator (ESP), additional energy use for reheating the flue gas would be a major drawback.

Response:

The final rule is not applicable to kraft recovery furnaces. See Section VI.C.5 of the preamble to the final rule for a response to questions about the types of fuels covered by the final rule, and options for facilities that determine meeting the final rule's emissions limits is infeasible.

Facilities Modeled

Comment:

Commenter (0338) argues the EPA has not accurately identified all the sources impacted by the rule, pointing out that it identified several industrial boilers from paper mills that had been retired or were controlled in its December 21st letter to the EPA regarding the EPA Draft 2016v2 Emissions Modeling Platform, and these are not reflected in the rule. The commenter also mentions that at least one of their members had identified two additional boilers in Wisconsin that may be subject to the rule. The commenter states that it is therefore unclear what the total amount of reductions would be achieved what the corresponding impact on nonattainment/maintenance areas would be. The commenter asserts that the EPA needs to better identify which facilities will be impacted by this rule and determine corresponding estimate costs prior to moving forward with this rule.

Response:

The EPA relied on the NEI, which is a comprehensive database of criteria and hazardous air pollutant emissions from stationary and mobile sources that is based upon data provided by State, Local, and Tribal agencies, and supplemented by data from the EPA, as the source of emissions data used to develop technical support materials for this rulemaking. We note that the EPA and the jurisdictions that submit information to the NEI do so in accordance with rigorous quality assurance and quality control procedures as outlined within the 2017 NEI Plan and related documents such as the Emissions Inventory System (EIS) Automated QA Checks for the 2017 NEI Spreadsheet.[94] Additionally, we received feedback during the public comment period regarding updates that should be made to the emissions inventories, particularly regarding emissions from major stationary sources, and have incorporated that feedback into the inventory files that support the final rule modeling and into the final technical support materials where we deemed it appropriate to do so.

In addition, the primary purpose of the EPA's *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. In the non-EGU screening assessment memorandum we presented

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[94] The two items referenced in this sentence are available at: https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data#doc

an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026.

We respond further to these comments in Section 2.2 (Non-EGU Industry Screening Methodology).

5.3.5.3 Monitoring, recordkeeping, and reporting

From Basic Chemical Manufacturing

CEMS and PEMS

Comments:

Commenter (0243) states that based on the applicability criteria in the proposed rule, boilers will have to install emissions controls and possibly CEMS to comply with the emissions limits and monitoring requirements. Although the commenter has not evaluated the cost of installing emissions controls and CEMS for these boilers, they anticipate that the cost per ton of NO_X emissions reduced would be significantly higher than the EPA's basis. According to the commenter, since the EPA's assessment for non-EGU boilers only considered boilers that emit 100 TPY of NO_X emissions, the commenter requests that the EPA consider a low emissions exemption for natural gas fired boilers to address boilers with very small ozone season and annual emissions.

Response:

See Section VI.C.5 of the preamble to the final rule for a response to comments requesting a limited use exemption for infrequently run boilers.

Comment:

Commenter (0300) states that in the proposed section 40 CFR 52.45, the cross-reference is inappropriate given this section applies to industrial boilers and the provisions referenced, 40 CFR p75, are related to acid rain.

Response:

40 CFR part 75 has been historically used for previous ozone transport FIP actions for monitoring protocols for boilers. The EPA disagrees with the commenter and finds that it is appropriate to use part 75 monitoring for non-EGU boilers. Additionally, we note that the final rule includes an alternative monitoring option that does not involve part 75 monitoring for boilers sized less than 250 mmBtu/hr.

Comments:

Commenter (0432) requests that the EPA consider allowing alternative monitoring approvals under the proposed FIP. The commenter explains that under the OAC Rule 3745-14 for NO_X SIP, facilities are allowed to request alternative monitoring mechanisms. The commenter states that their facility is in the process of obtaining an alternative monitoring approval in place of its current part 75 CEMS monitoring for compliance with the NO_X SIP and worries that the proposed rule, if finalized, may require a CEMS for natural-gas boilers, which would contradict the alternative monitoring approval, if received.

Commenter (0338) states the rule mandates facilities to install CEMs, and to conduct an initial compliance demonstration. The commenter states that Predictive Emissions Monitoring Systems (PEMS) should also meet monitoring requirements, and the EPA should allow for an annual testing compliance method in lieu of requiring CEMs. The commenter further states that the rule should specify what initial compliance demonstration is needed and specify that initial compliance tests should not be required for existing CEMs.

Commenter (0437) notes that many industrial boilers are not currently equipped with NO_X CEMS and points out that many regulatory programs (such as the Boiler MACT) allow for periodic stack testing and continuous parameter monitoring to show ongoing compliance, in lieu of CEMS. The commenter adds that even boilers with RACT or BACT limits are not always required to install CEMS but are sometimes allowed to demonstrate compliance via periodic stack testing or by using PEMS. The commenter also notes that Gas Turbine NSPS does not require NO_X CEMS if water or steam injection is the NO_X control method and parametric monitoring is used to demonstrate compliance between stack tests.

Commenter (0437) adds several states (North Carolina and Alabama, for example) have allowed legacy NO_X SIP Call industrial boilers to remove their NO_X CEMS (if not required by another federal rule) and instead use fuel usage and emissions factors based on historical data to calculate ozone season NO_X emissions. According to the commenter, it is reasonable for the EPA to require periodic stack testing and continuous parameter monitoring as the demonstration method for ongoing compliance with the proposed lb/MMBtu ozone season emissions limits and agrees that CEMS would be appropriate for units participating in a trading program because it is critical to measure mass emissions accurately for participation in such a program. However, the commenter states that if the EPA requires CEMS in the final rule, the rule will need to properly distinguish between obligations for newly installed CEMS and existing CEMS that have previously demonstrated conformance with Performance Specification 2 requirements and completed the initial performance evaluations. The commenter notes that Section 52.45(d) includes requirements to complete an initial 30-day compliance test within 90 days of installing pollution control equipment but does not specify if the test must be complete prior to May 1, 2026, ozone season or by some later date. The commenter also notes that it does not state whether this requirement applies only to newly installed CEMS, or if existing CEMS would also need to conduct this initial performance test.

Commenter (0437) states that if NO_X CEMS are used as the compliance method, a 30-day averaging period is consistent with the requirements contained in 40 CFR part 60, subpart Db at 60.44b(i). The commenter notes that emissions of CO and NO_X from pulp and paper boilers vary with changes in fuel and load, and a longer averaging period is also appropriate when a standard applies at all times, to ensure achievability of the emissions limits and avoid non-compliance during short transitional periods. The commenter adds that the EPA acknowledged the variability of boiler emissions in the preamble to the December 23, 2011, Boiler MACT rule. The commenter states that they would also support a 30-day averaging period for any parameter monitoring required by the rule, as this would be consistent with the precedent the EPA established in the Boiler MACT and other rules. The commenter relays that compliance with the emissions limits in Boiler MACT is demonstrated via periodic stack testing, continuous monitoring of operating parameters, and comparison of the 30-day average operating parameter value against a site-specific operating parameter limit, and states that this type of methodology would be appropriate if the EPA finalizes ozone season NO_X emissions limits for industrial boilers.

Commenter (0437) states that the EPA should add the cost of installing, operating, and maintaining CEMS to its control cost analysis and its regulatory impacts analysis. The commenter states that assuming that a suitable sampling location can be identified on a stack and is accessible, the cost to program, install, and certify the NO_X CEMS could be up to $500,000 based on recent project quotes and ongoing operation and maintenance costs could be up to $150,000 per year. The commenter notes that theses estimated costs are not based on the EPA's CEMS cost spreadsheet because that data is 15 years old and does not represent current day costs. The commenter states that these costs are not insignificant to forest products industry facilities.

Commenter (0421) supports the use of a PEMS option in the final rule for industrial boilers and uses this approach at some of their boilers that would be covered by the rule. As proposed, it appears to the commenter that the owner/operator would need to show that NO_X emissions are less than 0.056 lb/MMBtu for natural gas fueled boilers, and then request approval to use a PEMS. The commenter notes that NSPS subpart Db allows the use of PEMS for certain sized boilers, and therefore believes the option to use a PEMS should be included in this final rule.

Several of commenter's (0432) boilers that satisfy the proposed applicability criteria and are rated at or above 100 MMBtu/hour emit less than 100 tons of NO_X during the ozone season. According to the commenter, these boilers would be required to comply with the lb/MMBtu emissions limit and to potentially install and operate controls and CEMS despite providing little to no benefit at downwind receptors.

Response:

The EPA has modified the monitoring requirements for boilers as put forth in the proposed rule in consideration of comments we received on them. The final rule allows monitoring by PEMS systems for units sized 250 MMBtu/hr or less in conjunction with an annual stack test. The requirements for initial compliance demonstrations are provided within Section 52.45 of the final rule, and this section of the final rule provides that initial compliance testing is not required for emissions units equipped with CEMs that are operated pursuant to federally enforceable requirements.

Comments:

Commenter (0421) supports the EPA's proposed rule that allows a facility to seek an alternative monitoring procedure when the performance test results show NO_X emissions less than 70 percent of the applicable emissions limit, and the owner/operator decides not to install a CEMS. However, the commenter suggests that the EPA conduct a review of the proposed alternative monitoring procedure but not prolong the approval process with a public notice and comment process, as these emissions sources are lower emitting sources (*i.e.*, they emit 70 percent or less than the applicable emissions standard).

Response:

We disagree that a public notice and comment process is unnecessary in such circumstances and are finalizing requirements at Section 52.45(e)(1)(viii) outlining the procedures for owner/operators to follow when an alternative monitoring procedure is sought which include a public notice and comment process.

Comments:

Commenter (0421) states the proposed 40 CFR 52.45(g) reporting requirements require the submittal of excess emissions reports, continuous monitoring, and quarterly emissions reports. The commenter suggests 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 also clarify that only emissions and monitoring data from this time period should be included in these reports.

Response:

The EPA has considered this comment and agrees that since the emissions limits are only applicable during the 5-month ozone season which runs from May 1 through September 30, reporting should only be required during the second and third quarters of the year and we have modified the final rule's regulatory text accordingly.

Comments:

Commenter (0421) states some of their boilers that may potentially be subject to this rule in the future already have a NO_X CEMS installed. The commenter requests that the EPA clarify in the final rule that the 30-day initial compliance test is not required in cases where a NO_X CEMS monitor is already in service, and the rule should only require the owner/operator to follow the QA/QC requirements for the CEMS.

Response:

The EPA has added regulatory text to the final rule at 52.45(d) indicating that emissions units that are already operating a NO_X CEMs pursuant to a different, federally enforceable requirement, are not required to perform an initial compliance test and may follow the already in place QA/QC requirements.

Comments:

Commenter 0758 support the EPA's proposal to require continuous emissions monitoring to ensure compliance.

Response:

The EPA acknowledges the support offered by the commenter for use of CEMs to monitor compliance with this final rule. We have maintained this requirement for boilers with heat inputs equal to or greater than 250 MMBtu/hr, but are allowing alternative monitoring techniques for units sized less than this threshold given the lower amount of emissions such units are likely to produce.

5.3.5.4 Boiler Comments not Contained within Contractor's Report

Comment:

The pulp and paper industry has reduced its NO_X emissions by 48 percent since 2000.

Response:

Although the 48 percent NO_X emissions reduction noted by the commenter is commendable, on a national basis data from the EPA's NEI indicates that NO_X emissions from large industrial and electric utility facilities have fallen 77 percent since 2000, reflecting a significantly greater reduction than has occurred in the pulp and paper industry.

Comment:

The EPA assumes the level of control achievable by technologies like ultra-low NO_X burners on boilers with a heat input greater than 100 MMBtu/hr is 75 percent, but demonstratable reductions from the application of this technology may only be 40-60 percent from baseline.

Response:

The EPA's assumed control efficiency CE of 75 percent for units equipped with ultra-low NO_X burners was used within the screening assessment to identify impactful industries with emissions that could, on average, be controlled with the cost parameters noted in the proposed FIP. It was not intended that ultra-low NO_X burners capable of achieving a certain percent reduction be installed on all boilers subject to the final FIP's requirements. The final FIP does not require use of any specific type of control equipment, but rather requires that NO_X emissions limits be met based on the types of fuel combusted by the boiler, and there are a variety of different types of control equipment options available to meet these limits.

Comment:

The EPA should provide definitions for biomass, coal, distillate oil, natural gas, and residual oil.

Response:

We have provided definitions for coal, distillate oil, residual oil, and natural gas within the final FIP to clarify what types of fuels are covered by the boiler provisions of the final FIP. A definition for biomass has not been provided because that is not a primary fuel type covered by the final FIP's requirements.

Comments:

Commenters (0362, 0437) request that the EPA add definitions to avoid regulating limited-use and temporary boilers and suggests the following language:

Temporary Boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

1. The equipment is attached to a foundation.

2. The steam generating unit, or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
3. The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least 3 months each year.
4. The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Additionally, the commenter (0437) also requests the EPA add the following definitions:

Limited-Use Boiler means any boiler that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Response:

We did not find it necessary to provided definitions for these terms within the final FIP.

Comment:

There are disbenefits from the rule, including increases in GHGs and fossil fuel use, ammonia storage, and ammonia emissions which leads to PM emissions. (AF&PA)

Response:

NO_X emissions play a prominent role in ozone formation, and we anticipate that lowering NO_X emissions from boilers covered by the final FIP will outweigh any nominal increase in GHG emissions and fossil fuel use. Additionally, although some boilers may need to install SNCR or SCR to meet the final FIP's NO_X limits for boilers, many existing facilities already operate these controls and are able to store ammonia safely, and any ammonia emissions from facilities using these controls will be minimal and unlikely to cause PM air quality issues. Furthermore, information from the NEI indicates that a majority of the emissions units covered by the boiler provisions of the final FIP will be gas-fired units that will be able to meet the required emissions limits by installation of combustion controls such as low-NO_X burners with overfire air.

Comment:

The EPA did not take into consideration features of some of the state RACT rules it cites that account for different boiler designs, firing configurations, distinguishments between units firing "gas only" versus "gas and/or oil" fired units, and providing the option for obtaining an alternative emissions limit.

Response:

The EPA acknowledges that it may not be possible to retrofit all existing equipment subject to the boiler requirements of the final FIP with pollution control equipment capable of meeting a required emissions limit. Additionally, we agree that most State RACT rules allow sources to request an alternative limit upon a showing that a required limit can't be met. Therefore, the final FIP contains an allowance for sources to submit an engineering analysis and other documentation which demonstrates that a NO_X emissions limit for boilers cannot be met for a particular piece of equipment and request from the Agency an alternative emissions limit. This provision is found at Section 52.40(e) of the final rule.

Regarding commenter's point that state RACT rules that we cited for Massachusetts, Delaware, and New York contain varying emissions rates to account for differences in boiler design and/or fuel-firing configurations, we note that commenters have mischaracterized some of the emissions limits for Massachusetts. In particular, the Massachusetts limit cited by commenters for coal-fired stoker-boilers, which commenters contend is 0.33 lbs/MMBtu, is not accurate, as that limit applies to units burning "other solid fuels", not coal. We note that the two NO_X emissions limits for coal-fired boilers that are provided in the Commonwealth's regulation are both 0.12 lbs/MMBtu, which is lower than our proposed limit for coal-fired boilers of 0.20 lbs/MMBtu.[95] Furthermore, we note that although Massachusetts' previous requirement for boilers burning oil or oil and gas did contain different NO_X emissions limits based on boiler configuration and heat release rates[96], the currently applicable requirements no longer differentiate in that manner but rather requires a uniform emissions rate of 0.15 lbs/MMBtu for all oil and oil/gas boiler types other than a more stringent limit of 0.08 lbs/MMBtu for tangential, dual fuel (oil and gas) boilers sized 250 MMBtu/hr when burning natural gas[97]. Boilers that burn exclusively natural gas are subject to an emissions limit of 0.06 lbs/MMBtu across all boiler types[98]

Regarding commenter's points pertaining to Delaware's NO_X control regulation, we note that although older units that qualify for the exemption within section 1.2.1 of 7 Delaware Administrative Code (DAC) 1142 are provided with NO_X emissions limits that do vary, per Table 3.1 of 7 DAC 1112, by boiler type, and agree that those limits are higher than the limits in our proposed FIP, newer units are faced with the more restrictive NO_X emissions limits contained within section 1.3 of 7 DAC 1142 which does not provide any differentiation by boiler type.

Regarding commenter's mention of New York's NO_X control regulation, we note that the state's NO_X RACT rule, referred to as subpart 227-2, RACT for Major Facilities of Oxides of

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[95] See the Code of Massachusetts Regulations (CMR) at 310 CMR 7.19(b)(1) and (2).

[96] See 310 CMR 7.19(4)(a)(3 and 4).

[97] See 310 CMR 7.19(4)(b)(3 and 4).

[98] See 310 CMR 7.19(4)(b)(5).

Nitrogen (NO_X)[99], contains uniform NO_X emissions limits for all of the coal-fired boiler configurations addressed by the state's rule. New York's rule does provide for higher emissions limits for units fueled by both oil and gas, and we note that our final rule does so as well by providing a methodology to derive an emissions limit for such units based on the heat inputs and emissions limits of each fuel.

Comment:

(CIBO's letter) Requiring controls that are not cost effective threatens the competitiveness of U.S. industries and may lead to job losses at a time when the nation's economy is suffering from high inflation and appears headed towards a recession.

Response:

The EPA addressed the cost effectiveness of the controls in Section V.B. of the preamble. The EPA notes its costs are representative and any individual unit cost that varies from that representative value does not disqualify the representative nature of that cost. To the extent that a particular unit faces an extreme economic hardship to install the necessary controls that is different from other units in the industry, the final rule allows sources to apply for a case-by-case limit. The case-by-case limit is discussed further in Section VI.C of the preamble. Additionally, we have successfully implemented previous transport rules without harming the competitiveness of U.S. industries and expect the same outcome from this forthcoming final rule.

Comment:

The EPA should exclude units included in the NO_X SIP call program. (Dow)

Response:

The EPA promulgated the NO_X SIP call almost 25 years ago to address, for purpose of the 1979 one-hr ozone standard, similar problems as are being addressed by today's final rule, but for a much less stringent ozone standard. The ozone standard has been strengthened three times since 1979, and this current final action address ozone transport issues associated with the 2015 ozone NAAQS of 70 ppb. Given that the ozone standard addressed by this final action is considerably more stringent than the 1979 ozone standard which was served by the NO_X SIP call, we do not agree with commenter's assertion that emissions units included in the NO_X SIP call should be excluded from this final action. This is because more significant reductions in upwind NO_X emissions are needed for downwind states to the more stringent 2015 ozone NAAQS than were needed for states to meet the 1979 NAAQS.

Comment:

The National Lime Association concurs with the EPA's conclusion expressed within the proposed FIP that there are no boilers in the lime industry that meet the proposed FIP's applicability criteria. If the EPA subsequently decides to regulate emissions units from this

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[99] See 6 CRR-NY III A 227-2.4

industry, a separate notice of proposed rulemaking must be put forth.

Response:

The EPA acknowledges the confirmation made by the National Lime Association regarding the lack of boilers subject to the proposed FIPs applicability criteria and has not put forth regulatory requirements for other types of equipment in the lime industry such as industrial process equipment in the final FIP.

Comment:

Commenter (0308) believes within the selected industrial source categories there is unequal treatment of industrial boilers as affected units. No explanation is provided as to why industrial boilers are included in the iron and steel manufacturing category but not in the cement and glass products categories. The treatment of the iron and steel manufacturing industry with respect to these other industries and their industrial boilers should be consistent and industrial boilers removed as an affected unit from the iron and steel industry category. § 52.43 which regulate the iron and steel industry includes as affected units industrial boilers. However, § 52.42 Cement and Concrete Product Manufacturing Industry and § 52.44 Glass and Glass Product Manufacturing Industry do not include industrial boilers as an affected unit. Each of these industries include industrial boilers as part of the facility. For consistency with the treatment of the iron and steel manufacturing industry with respect to these other industries, industrial boilers should be removed as an affected unit from this category.

Response:

The commenter asserts that there are industrial boilers located at facilities within the cement and concrete industry and the glass and glass products manufacturing industry but did not provide specific information regarding this assertion. The emissions data available to the EPA has led us to conclude that there are no boilers sized 100 MMBtu/hr or greater at facilities in the Cement and Concrete industry or the Glass and Glass Products industry that are within a state affected by this final action, and so we have not assumed emissions reductions from such equipment at these locations.

Comment:

Is it the EPA's intent to override exemptions for boilers that exist under other regulatory programs, such as 40 CFR 63 subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, wherein an exemption exists for boilers used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels, due to the EPA concluding that add-on controls were not technically feasible for these units?

Response:

It is not clear that any such boilers as mentioned by the commenter exist within any of the industries affected by this final rule. We have not provided an exemption for the units described by the commenter. However, the final rule includes procedures and criteria for a facility owner or operator to request EPA approval of an alternative case-by-case limit based on a showing of technical impossibility or extreme economic hardship.

Comment:

Will NO_X emissions testing done pursuant to other requirements suffice for purposes of the final FIP?

Response:

Section 52.45(e)(1)(ii) of the final rule allows, in some circumstances, NO_X monitoring requirements currently required at a facility to suffice for purposes of the monitoring requirements of this final action.

Comment:

There may be instances where existing control requirements for other pollutants inhibit the ability of a boiler to meet the EPA's proposed NO_X limits. For example, some units use a sodium-based absorbent to comply with boiler MACT requirements to treat flue gas for HCl. Sodium is a poison in the SCR process; would this emissions unit need to install different controls for MACT compliance to be able to install SCR controls for compliance with the FIP's NO_X limits? (WPC)

Response:

In cases such as that described by the commenter, the facility should document its concern that control techniques used to comply with other regulatory requirements conflict with the ability of the emissions unit to meet a NO_X emissions limit required by this final rule and submit that documentation to the agency as part of a request for an alternative emissions limit.

Comment:

Intra-state trading should be allowed, as this would enable a more cost-effective means of meeting the FIP's objectives. (WPC)

Response:

Although the EPA's final FIP does not provide this type of compliance flexibility, states will have the option of submitting a SIP rule to replace the EPA's FIP requirements, and it's possible that such a state plan could allow for intra-state trading. The EPA would evaluate such a requirement within a state plan at the time the EPA acts on the state's request.

Comment:

If a source is subject to the NO_X limits of 40 CFR 60.44b, no further NO_X reductions should be required by the EPA's final FIP. (Corteva)

Response:

The EPA disagrees that compliance with the NO_X limits of 40 CFR 60.44b should exclude a source from the requirements of this final FIP action. The emissions limits from 40 CFR 60.44b were promulgated 15 years ago and do not reflect the greater level of emissions reduction control achievable by the current state of air pollution control technology.

Additionally, as noted in our proposal, a number of states have adopted NO_X emissions limits as RACT that are comparable to the emissions limits we are finalizing in today's action.

Comment:

A request was made to exclude co-gen units from the final FIP.

Response:

We considered the request to exclude cogeneration units from the final FIP but are not doing so. Although cogeneration units do provide an environmental benefit by producing both electricity and heat, NO_X emissions can still be substantial from this equipment and so we are not excluding them from the final FIP's requirements.

5.4 Submitting a SIP

Comments:

Commenter (0275) states it is operating electric vehicle charging programs to serve residential and commercial customers, and the state of Wisconsin plans to invest approximately $80 million in federal funding over the next five years to expand electric charging stations throughout the state. These initiatives should result in a reduction in mobile source NO_X emissions within the state. However, as proposed the FIP does not provide a clear mechanism for Wisconsin or neighboring states to take these initiatives into account, or otherwise capture the associated reductions in determining compliance with this rule. To address this, the EPA should provide a mechanism in the final rule to allow Wisconsin to take the associated reductions into account for purposes of complying with this rule. The rule does currently note states may submit either a full state implementation plan (a "full SIP") or a partial plan (an "abbreviated SIP") to address compliance with this rule in place of the otherwise-applicable requirements of the FIP. WEC Energy Group requests the EPA specifically provide an option for submission of an abbreviated SIP to allow Wisconsin to specifically capture emissions reductions related to electrification as a means to meet the proposed rule's NO_X budgets.

Commenter (0798) disagrees with the EPA's reasoning that, "to replace the non-EGU portion of the FIP in a state, the state's SIP submission must provide adequate provisions to prohibit an equivalent or greater amount of NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP submission has been approved by the EPA to replace the FIP." The commenter believes that this requirement is unlawful for the following reasons (1) 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). The commenter provides the example, "if Arkansas is able to show that it no longer has a significant contribution to the Brazoria receptor before the final FIP deadline for non-EGU emissions reduction standards…, then there would no longer be any statutory basis for the EPA to impose a good neighbor FIP on Arkansas;" and (2) given that the limits imposed in the Proposed Rule are not the same as the statewide emissions reductions that the EPA modeled as being sufficient to resolve any significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind states, the EPA cannot rationally judge a SIP submission based on whether it reduces emissions by a greater amount than the Proposed Rule's limits would – the total amount specified at the Non-EGU Screening Assessment.

Commenter (0350) also states although each state should be afforded discretion to develop an effective SIP, as a part of this proposed rule, the 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.

Response:

These comments are responded to in Section VI.D. of the preamble.

5.5 Title V Permitting

Comments:

<u>Title V Permitting – Overview of Comments</u>

In general, commenters (0266, 0324, 0336, 0359, 0440) briefly discuss the impacts of the proposed rule to the state permitting process, specifically Title V. A few commenters representing the cement industry express their concerns regarding the proposed daily allowable NO_X emissions cap – essentially, questioning why the EPA is proposing semiannual testing for the cement and concrete product industry sector for a 5-month ozone season rule. At least one commenter notes that the EPA's proposal will require states to revise existing operating permits for sources subject to the rule as well as evaluate construction permit applications for sources required to install additional emissions control technology. Another commenter suggests that the EPA create a template to streamline the permit revision process and avoid further overburdening state and local permitting programs.

<u>EPA Authority – Regulatory Permitting Process</u>

Commenter (0266) requests, in general, clarity on state's role in compliance oversight and their obligations to review Title V compliance reports for compliance with U.S. EPA's FIP limitations. The commenter expresses concerns that the proposed FIP will impose a higher resource burden to states (*e.g.,* providing specific monitoring requirements) than experienced under previous trading programs, which aimed to minimize the resource burden to States.

Commenter (0324) suggests that the EPA develop permit templates, as they have done for previous rules (CSAPR) for the different types of industrial sources subject to this rule. The commenter requests that, at a minimum, that the EPA develop permit templates for permitting programs to reference for EGUs and each non-EGU industrial source category subject to the proposed rule. According to the commenter, permit templates can streamline the permit revision process and avoid further overburdening state and local permitting programs. The commenter stresses the importance for the EPA to relieve the regulatory burden on state and local agencies. Furthermore, the commenter recommends that the EPA also include a provision in the template or in the rule to allow for compliance extensions – NESHAPs existing sources cited as an example.

Commenter (0340) claims that the EPA disregards the permitting programs implemented by states, as well as its own rulemaking processes for NSPS and the associated Emission Guidelines for existing sources, as well as other source and pollutant emissions standards. The commenter implies that by subjecting specific EGUs and non-EGUs industries, equipment, and processes to the proposed "daily backstop" emissions rates during ozone season, the EPA circumvents the permitting programs and regulations implemented by states to determine applicable permitted emissions standards. The commenter briefly defines and describes the intent of the following permit programs/regulations – NSPS, BACT, NSR, PSD, etc., and recommends that the EPA remove the proposed operational emissions limits from the rule. The commenter asserts that the EPA is effectively setting new BACT standards without providing demonstrated, sound, technical and engineering information for the application of control technologies and eliminating states' use of case-by-case analysis, which allows for consideration of energy, environmental, and economic impacts and other costs in evaluating controls. The commenter implies that emissions limits for non-EGU processes in the proposed rule are essentially changes to existing permitting regulations, as any future units will be also subject to the same restrictions.

Response:

The vast majority of units subject to this rule will already be subject to title V permits and will only require updates to their existing title V permits reflecting the requirements in the rule. Because an existing title V source may continue to operate following submission of a request for a permit revision to the title V permitting authority, the title V permitting process should not delay implementation of the rule. It is possible that some sources may need to seek minor or major NSR permits (e.g., prevention of significant deterioration or nonattainment new source review). The report by SC&A on control installation timing in the docket for this rulemaking discusses the time and resources that could be needed for preconstruction permitting processes. For the reasons provided in the control installation timing report and in Section VI.A of the preamble, we conclude that these permitting processes will not affect a source's ability to timely comply with this rule.

The EPA is not providing permitting templates at this time for title V permit changes that may be associated with this rulemaking. Consistent with our approach in CSAPR, the EPA may consider developing permit templates at a later point and intends to work with permitting authorities if they have questions or wish to have further conversations regarding this topic. *See* 76 FR 48208 (August 8, 2011); Anna Wood, Director, Air Quality Policy Division, EPA, *Title V Permit Guidance and Template for the Cross-State Air Pollution Rule* (May 13, 2015). To the extent permitting authorities may find it useful, they can develop templates for applications and permit content as appropriate to implement their existing permit program requirements. The Agency is cognizant that a single set of EPA-developed templates may not be an effective means for implementing state-adopted permit programs.

The EPA disagrees with commenters' assertions that this final rule disregards permitting and other CAA programs. Nothing in the final rule affects or undermines any of the operating permit or preconstruction permit requirements that apply to new or existing stationary sources. Because the major NSR programs require new sources to install the "best available" controls (in attainment areas) and to achieve the "lowest achievable" emissions rates (in nonattainment areas), application of those control standards to individual sources on a case-by-case basis will in many cases result in control requirements more stringent than the emissions limits established for entire categories of emissions units in this final rule. As explained in detail in the proposed rule and in Section VI.C of the preamble, the EPA has largely based the non-EGU emissions limits and requirements on applicable NSPS, NESHAPs, state RACT rules, and existing permit requirements, many of which were established years ago and thus reflect control technologies that are cost-effective and widely in-use across the relevant industries. Affected units under the final rule remain subject to all applicable operating and preconstruction permitting programs. The final rule establishes an additional set of applicable CAA requirements to implement good neighbor requirements for the 2015 ozone NAAQS for the sources that are subject to this rule. (For EGUs, we note that participation in the amended Group 3 program will continue to satisfy good neighbor requirements for the 2008 ozone NAAQS, as established in the CSAPR Update and Revised CSAPR Update, for the states covered by those rules, as well as for the 1997 ozone NAAQS, for eleven of those states. See Preamble Section VI.F.3.) This rule does not make RACT, BACT, or LAER determinations for any source.

5.6 Relationship to Other Emissions Trading and Ozone Transport Programs

Comments:

Commenters (0308, 0309, 0323, 0331, 0336, 0350, 0359, 0366, 0367, 0395, 0411, 0421, 0424, 0430, 0432, 0532) briefly describe the role trading programs have played (in their states for example) in reducing emissions and improving air quality, particularly in the absence of the application of new and innovative control technologies, and urge the EPA to consider the impacts of the programs when finalizing the proposed FIP. Many of the commenters argue that these on-the-books control programs often result in NO_X emissions reductions comparable to the proposed FIP. To avoid duplicity of requirements that can add additional costs to states and regulated entities, commenters urge the Agency to omit sources from the proposed FIP that are subject to one or more alternate trading program.

Commenter (0359) states that NOx ozone season emissions (in West Virginia) have been reduced by 90 percent in the last 25 years (since 1997), according to data reported to the EPA's Clean Air Markets Division; reflecting the retirement of 19 coal fired EGUs along with emissions reductions from active units. The commenter expresses concern that the proposed rule expects an additional 28 percent reduction from NOx ozone season emissions from EGUs beyond the Revised CSAPR Update reduction of 23 percent that just went into effect with the 2021 ozone season.

Commenter (0421) argues that companies operating under state SIP approved cap-and-trade programs should be excluded from the CSAPR FIP regulatory program. The commenter briefly describes the cap-and-trade program for their state, Texas; stating that larger and intermediate sized boilers are subject to a NO_X cap-and-trade program, where annual emissions are combined together to demonstrate compliance with an annual emissions limit for each plant site in this region. The commenter further argues that the program is an effective way to limit NO_X emissions from an industrial site or group of industrial sites, thus is an effective tool to reduce ozone air pollution in the Houston, Galveston, and Brazoria Ozone Non-Attainment area/region and presumably reduce NO_X emissions involved in downwind transport.

Commenter (0414, 0532) objects to the EPA implementing this rule in states where the Regional Haze Rule is already enforcing and effectively reducing NO_X emissions and suggests that the desired outcomes the EPA seeks with this rule will likely be achieved through the regional haze program. The commenter (0532) points out that, in the case of Utah, the EPA has gone on the record defending the effectiveness of the Utah SIP submission. The commenter also mentions that Utah's regional haze program effectiveness is determined using four factors: (1) cost of compliance; (2) time necessary to achieve compliance; (3) energy and non-air quality environmental impact of compliance; and (4) the remaining useful life of any existing source is subject to such requirements.

Response:

To the extent that the commenters suggest that compliance with regulatory requirements adopted to address one obligation under the CAA should in itself be a basis for exempting a given source from compliance with regulatory requirements adopted to address a different CAA obligation, the EPA disagrees. Nothing in the CAA supports the notion that sources should have to comply with only some, rather than all, of the Act's requirements. As discussed in the preamble, the Agency's analysis for this rulemaking indicates that additional emissions reductions are needed to address the requirements of the CAA's good neighbor provision with respect to the 2015 ozone NAAQS, notwithstanding previous regulatory requirements with which some covered sources may be complying to address other CAA requirements. For discussion of the EPA's analysis and findings concerning the need for additional emissions reductions, see Sections IV and V of the preamble. For discussion of the specific regulatory requirements identified by the Agency for various types of sources under this rule, including emissions trading elements for some sources, as well as discussion of the applicability criteria, see Sections VI.B and VI.C of the preamble. For discussion of the EPA's efforts to coordinate the compliance activities under various trading programs to avoid duplication of activities for EGU sources, see Section VI.F of the preamble.

Comment:

Commenter (0336) argues that the proposed FIP, as written, will satisfy the requirements of the NO_X SIP Call for EGUs larger than 25 megawatts electric, because both rules call for NO_X reductions. The commenter recalls that in the previous CSAPR Update, the EPA allowed the option for any NO_X SIP Call state that was also subject to the Revised CSAPR Update to voluntarily submit a SIP revision to expand the applicability of the Group 3 trading program to include all NO_X Budget Trading Program units, which in addition to large EGUs also include large non-EGU boilers and combustion turbines with a maximum design heat input greater than 250 mmBtu/hr. The commenter further adds that as part of such a SIP revision, the state would be allowed to issue additional emissions allowances capped at a level intended to preserve the stringency of the Group 3 trading program. The commenter announces that they will likely implement the finalized proposed FIP in lieu of the (Virginia) state SIP submission; arguing that there is little, if any, additional environmental benefit gained from the adoption of the requirements into the state SIP rather than implementation through the FIP.

Commenter further believes the EPA should supersede the NO_X Budget Trading Program with the provisions in the final rules, adding that requiring these sources to comply with both is duplicative, creates unnecessary paperwork for state and regional EPA staff, and requires the use of scarce state resources for no environmental gain. The commenter also questions why some units are subject to the NO_X Budget Trading Program but not the proposed FIP, identifying at least 5 boiler units that are currently subject to the NO_X Budget Trading Program, but not the FIP (BLR010, BLR011, BLR012, BLR013 and BLR014, as identified in the Clean Air Market Division's database).

Response:

For discussion of the coordination of this rule's requirements for EGUs and the requirements for EGUs under the SIPs adopted by states to comply with the NO_X SIP Call, see Section VI.F of the preamble. For discussion of the former options to expand applicability of the CSAPR seasonal NO_X trading programs to include large non-EGU boilers and combustion turbines to address NO_X SIP Call requirements, see Sections VI.D.2 and VI.D.3 of the preamble. For discussion of the applicability criteria for non-EGU sources affected under this rule, see Section VI.C of the preamble. Comments suggesting revisions to the NO_X SIP Call regulations are beyond the scope of this rulemaking.

Comment:

Commenter (0430) briefly describes how they currently use power purchase agreements to source power (energy generated from renewable sources), and how they continue to transition and diversify their portfolio to include primarily renewable sources (noting the retirement of coal-burning units, including a 903 MW unit at the Schahfer Generating Station). The commenter further notes that their coal-burning units are dispatched by the MISO which takes into account economics, reliability of the MISO system, and unit availability, and notes that NO_X limits are continuously controlled, as units are equipped with SCR technology. According to the commenter, they have been able to reduce NO_X emissions by more than 80 percent since 2005, and is targeting a 99 percent reduction by 2030 (with the help of investments in control technology and through the retirement of coal units).

Additionally, commenter (0430) notes that they are required to reduce NO_X emissions rates under a federal consent decree entered into between the commenter, the EPA, and the State of Indiana in 2011 [Consent Decree entered in United States and the State of Indiana v. Northern Indiana Public Service Co. (N.D. Ind. July 22, 2011)]

Commenter (0375) claims that the state of Arkansas is doing its part to reduce emissions in the electric energy sector; adding that the state has not added a new fossil fuel unit to their resource mix in over a decade. Additionally, the commenter themselves have approved hundreds of millions of dollars of investment in new wind, solar, and storage facilities in recent years. The commenter also notes that they implemented an Arkansas statute that allows customers to install up to 20MW net-metering facilities to give Arkansas families and businesses some ability to hedge environmental compliance cost risk and natural gas price risk.

Commenters (0395, 0411) describe effort made to diversify their generation portfolio to include more renewable resources – *e.g.*, renewables contributed 36 percent of the total capacity (according to commenter (0411)). Commenter (0411) announces plans to expand the amount of renewable resources used for generation (by more than more than 10,000 MW, over ten years); adding that they plan to systematically retire all coal units by 2034 resulting in a forecasted reduction in CO2 (and likely NOx) emissions of over 80 percent by 2030. Working together with appropriate parties (*e.g.*, coordinating with ISO/RTOs) to develop resource plans, the commenter notes that they are able meet GHG reduction targets by 2030. According to the commenter, these resource plans balance the need for carbon-free electric generation resources with the public need for reliable and affordable electricity.

Response:

The statements in the comments do not appear to seek a response from the EPA concerning any aspect of the proposal.

Comment:

Commenter (0411) supports the concept of an allowance trading program for criteria pollutants when done correctly – *i.e.*, provides regulated entities with a degree of certainty and flexibility to facilitate proper planning and limits price volatility in the early years while accommodating existing retirement plans. The commenter also remarks that it is critical to have final rules in place well before the beginning of the first compliance period to allow for proper planning. The commenter briefly describes their experiences participating in the 1990 SO_2 allowance trading program. Specifically, the commenter notes that, under the SO_2 allowance trading program they were able to successfully decrease emissions in SO_2 from electric power plants by 36 percent (from 1990-2004), while also increasing electricity generations by 25 percent, over the same period – at a substantially lower cost when compared to command-and-control programs. The commenter implies that the 1990 SO_2 allowance trading program should be used by the EPA as model for the proposed FIP.

Response:

The EPA agrees with the commenter's observation that trading programs have long been demonstrated to be effective mechanisms for achieving emissions reductions from the electric power sector. The Agency disagrees with the commenter's suggestion that the trading program implemented under this rule would provide insufficient planning certainty, flexibility, or lead time. For discussion of the CAA provisions underlying this rule's requirements and the timing associated with those provisions, the Agency's analysis of the lead times required to implement various control measures, and the Agency's determinations concerning the stringency of requirements under this rule at various compliance deadlines given the CAA's timing requirements and the control measure implementation lead times, see Sections II.C, III, V, and

VI.A. of the preamble. For discussion of changes from the proposal adopted in the final rule to facilitate compliance planning by providing greater certainty on future state emissions budgets and to provide greater flexibility in instances where EGU owners might choose to rely on unit retirements as part of their compliance strategies, see Sections VI.B.1, VI.B.4, VI.B.6, and VI.B.7 of the preamble.

Comment:

Commenter (0411) states their belief that the proposed FIP will adversely impact other regulatory requirements. The commenters clarify noting that programs, like the Mercury and Air Toxic Standards (MATS), Title V permits, 40 CFR part 60 and part 75 Continuous Emission Monitoring Systems ("CEMS") QAQC, etc., all have requirements to conduct a variety of different emissions tests, at specific load requirements, and at prescribed frequencies, and coordinating testing activity on units that may not be available due to dispatching challenges associated with allowance budgets could lead to non-compliance due to expired test windows. The commenter offers examples where quarterly testing (for units required to conduct PM and HCl testing at a baseload condition) under MATS cannot be performed within the allotted timeframe and urges the EPA to consider creating an exception from the allowance requirement in the event of required testing.

Response:

Although the comment is framed in terms of a broad assertion concerning potential conflicts with other regulatory requirements, the only specific regulatory requirements discussed in the comment relate to emissions testing. The EPA disagrees with the commenter's suggestion that exceptions from allowance holding requirements for EGUs are needed under this final rule to allow the EGUs to conduct emissions testing. This rule imposes no new emissions testing requirements on EGUs. The EPA's other allowance trading programs do not provide exceptions to allowance holding requirements for periods of emissions testing, and sources have extensive experience in scheduling their required emissions tests as needed to coordinate with electrical dispatch schedules. The commenter offers no support for its speculative contention that the allowance budgets under this rule could be inadequate to cover emissions during testing, and the EPA sees no merit in the contention.

Comment:

Commenter (0309) states that the state of Delaware has interpreted applicability of the "New Source Review" requirements at 7 Del. Code Regs § 1125 (Regulation 1125) with respect to the nonattainment pollutant NO_X, as affording the Department the authority to establish a facility-wide emissions limitation for NO_X as the permitting mechanism for ensuring the refinery's compliance with the NNSR requirements. The commenter mentions that they entered in an agreement with the Department that allowed an initial NO_X Cap for the refinery to be 2,525 tpy beginning in calendar year 2011, which has been evaluated over each twelve consecutive month rolling period and has been reduced to 1,650 tons in subsequent years. The commenter adds that they also agreed to accept a NO_X Cap for the refinery of 1,500 tons, in the aggregate applicable during the period of May 1 through September 30 of each calendar year (the Ozone Season Cap). The commenter further adds that they have also established a plantwide applicability limit for NO_2, consistent with federal regulatory requirements governing PALs. The commenter notes that all NO_X emissions are conservatively assumed to be NO_2 for purposes of both baseline actual NO_2 emissions rates and proposed plantwide applicability limit emissions rate for NO_2 sources at the refinery.

Response:

The statements in the comment do not appear to seek a response from the EPA concerning any aspect of the proposal. In addition, the comment is moot, because the final rule does not cover sources in the state of Delaware.

Comment:

Commenter (0367) acknowledges that states in the Northeast and mid-Atlantic have struggled for decades with ozone pollution, due in large part to transported ozone pollutants from upwind and neighboring states. The commenter briefly discusses the ozone designation and classification for New York, New Jersey, Delaware, and Connecticut as support. More specifically, the commenter mentions that New York's nonattainment status impacts nearby states despite these states implementing stringent NO_X and VOC control programs and successes in cutting in-state emissions. The commenter identifies the following programs and practices currently employed by these states, including:

- Stringent Reasonably Available Control Technology (RACT) on all major NO_X and VOC stationary sources, including power plants and major non-electric generating units.
- In New Jersey, regulation of power plants that operate on High Electric Demand Days (HEDDs) when ozone concentrations are often elevated and regulation of distributed generation/demand response internal combustion engines. New Jersey's rules for stationary reciprocating internal combustion engines do not allow the use of uncontrolled engines for the purpose of distributed electric generation or demand response in nonemergency situations. Similarly, Delaware has a strong multi-pollutant rule and regulates stationary generators. New York stringently regulates combustion turbines and internal combustion engines used for demand response.
- In New Jersey, State-of-the art (SOTA) air pollution control requirement for newly constructed, reconstructed and modified equipment and control apparatus.
- Adoption of California's motor vehicle emissions standards, which place more stringent controls on the amount of NO_X emitted from motor vehicles than federal emissions standards. New York and Connecticut have adopted the Low Emission Vehicle (LEV) III emissions standards, which apply to all 2017 through 2025 model year vehicles up to 14,000 pounds gross vehicle weight rating.[36] Massachusetts has likewise adopted LEV standards, as well as aggressive Zero Emission Vehicle (ZEV) measures, with an aim of making 30 percent of all sales of new medium- and heavy-duty vehicles zero emissions by 2030. Beginning with model year 2009, New Jersey incorporated by reference California's Low Emission Vehicle standards, including the zero-emissions sales requirements, to ensure the lowest emitting vehicles in the nation are sold in New Jersey. New Jersey also has some of the most stringent rules in the country for vehicle

idling and heavy-duty vehicle inspection and maintenance using on-board diagnostics technology.

- Statewide Enhanced Vehicle Inspection and Maintenance (I&M) requirements for motor vehicles that include testing of older, high-emitting vehicles to significantly reduce on-road mobile emissions.
- Adoption of regional measures to reduce VOC emissions from a variety of large source categories that have been recommended by the OTC, including consumer products, architectural and industrial maintenance coatings, portable fuel containers, adhesives and sealants, asphalt paving, and solvent metal cleaning processes.
- Lowest Achievable Emission Rate (LAER) standards on all new major sources of NO_X or VOC, and on all existing sources that would undergo major modifications with emissions above certain project thresholds.
- In New Jersey, adoption of measures to control NO_X emissions from Municipal Waste Combustors and natural gas pipeline compressor stations. New York has also adopted regulations limiting NO_X emissions from municipal solid waste combustion units. Connecticut has stringent NO_X limits for municipal waste combustors as well.
- In New York, regulation of certain oil- and natural gas-fired combustion turbines, referred to as "peaking units," to lower their allowable NO_X emissions during the ozone season. Connecticut also has a rule to limit emissions from peaking units at non-major sources of NO_X, and stringent NO_X limits for all units at major sources of NO_X.
- In the City of New York, adoption of significant additional measures to reduce emissions of ozone precursors within its jurisdiction.

Response:

The statements in the comment do not appear to seek a response from the EPA concerning any aspect of the proposal.

Comment:

Commenter (0521) mentions air quality control measures are an integral component to the EPA's Integrated Planning partnership that includes the state department – MDNR. The commenter reiterates their commitment to improving air quality; noting that measure already taken have reduction ozone season emissions by 25 percent since 2010.

Response:

The statements in the comment do not appear to seek a response from the EPA concerning any aspect of the proposal.

Comment:

Commenter (0411) agrees with the EPA's finding that a 25-megawatt threshold is appropriate for including electric generating units (EGUs) in the allowance trading program – a precedent set by and aligned with other existing emissions trading programs, including the Acid Rain Program, the NO_X SIP Call, CAIR and CSAPR. The commenter agrees with the EPA conclusion that inclusion of these sources smaller than this would result in a significant cost (to states and regulated entities) without corresponding reductions in NO_X emissions. The commenter further supports the EPA findings that current data does not offer a compelling reason to depart from the practice of excluding these small EGU sources as part of the rule.

Response:

For discussion of the EPA's determination with respect to the use of a 25-MW size threshold for EGUs in the final rule, see Section V.B.3.b of the preamble.

Comment:

Commenter (0308) asserts that there are a number of instances where the proposed rule is either in conflict with or excludes exemptions or compliance alternatives afforded sources in other federal regulations.

Response:

The EPA disagrees with the comment. The possibility that the provisions of one regulation promulgated for one purpose differ in some way from the provisions of a different regulation promulgated for a different purpose does not indicate a conflict between the regulations. Likewise, the possible existence of an exemption for a particular source under one regulation promulgated for one purpose does not dictate that an exemption for that source must be provided under a different regulation promulgated for another purpose. The commenter has not identified any instance where it would be impossible to comply with the requirements of this rule (as proposed) and the requirements of another regulation.

Comment:

Commenters (0373, 0395) highlight that are a number of EPA initiatives, either in process or imminent, that impose a new burden on fossil-fueled EGUs, as well as potentially lowering PM and ozone standards, which should be considered – *e.g.*, Regional Haze Rule, MATS revisions, replacement of the Affordable Clean Energy rule. According to the commenters, each initiative single handily has placed stressors and uncertainty on the fossil-fueled electric generating sector, and collectively they have discouraged investment into existing plants and the construction of new plants.

Commenter (0414) alluded to the fact that the likely retirement of existing coal-fired EGUs does not stop with the proposed rule for increasing expanding and strengthening the CSAPR program. The commenter warns that other upcoming major EPA rules could put at risk additional amounts of coal-fired generating capacity having to retire over the next decade. These other EPA rules include the following:

- Coal combustion residuals ("CCR") rule;
- Effluent limitations guidelines ("ELG") rule;
- Replacement rule for the Affordable Clean Energy ("ACE") rule; and
- Implementation of possible revised (more stringent) $PM_{2.5}$ and ozone standards.

Response:

Comments speculating about the requirements of potential future EPA rules and the possible impacts of such potential future rules are beyond the scope of this rulemaking.

6 Environmental Justice and Stakeholder Outreach

6.1 Community Health

Comments:

Commenters (0247, 0265, 0257, 0273, 0277, 0285, 0296, 0352, 0367, 0402, 0492, 0527, 0543, 0628, 0646, 0668, 0707, 0714, 0722, 0758, 0835, 0863, 0879, 0881, 0885) acknowledge that certain populations (*e.g.*, racial/ethnic minorities, low-income communities, indigenous groups, children, the elderly, the less-educated, individuals with pre-existing health conditions) are disproportionately exposed and vulnerable to NO_X and ozone emissions, which are extremely harmful to human health – may lead to maternal and reproductive health issues, respiratory problems like asthma, and premature death. Commenter (0492) mentions that American Lung Association's 2022 State of the Air Report, states that people of color are 3.6 times more likely than white people to live in counties with the worst air pollution. Commenter (0758) explains, "Across the nation, people of color are consistently overrepresented in areas with high ozone levels, including areas that are in nonattainment of the 2015 ozone standard. Of people living in counties projected to violate the standard in 2023, 37 percent identify as Hispanic, compared with only 19 percent of people nationwide, and 35 percent identify as not white, compared to 27 percent nationwide." Commenters state that the proposed rule will provide immediate benefits to these groups by targeting upwind sources of those pollutants and should be adopted quickly to set strong standards. To illustrate, commenter (0885) states that the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards would put in place crucial standards to protect families and communities, preventing up to 1,000 premature deaths and avoiding 2,000 hospital and emergency room visits and 1.3 million cases of aggravated asthma, which is especially important for communities of color, and low-income and other marginalized communities that disproportionally suffer from poor pollution management.

Commenter (0527) expresses support for the inclusion of emissions limits for major polluting industries in the proposed rule. Commenter explains that these industries often produce cumulative effects that place heavy burdens on Black communities, so it is crucial that the full breadth of industrial sources that adversely impact the health of communities of color be subject to these emissions reduction standards.

Commenter (0293) analyzed the health and equity metrics for the last-to-retire coal plants in Minnesota as well as the proposed fossil fuel gas combined cycle facility planned to be constructed in 2027 in Superior, Wisconsin. Commenter explains:

"The locations of these three power plants… lie immediately upwind of the state of Illinois, which contains numerous low-income communities and census tracts comprised disproportionately of Black, Indigenous, and people of color (BIPOC) communities. Thus, these three plants pose new and/or continuing non "Good" Neighbor threats to underserved BIPOC neighbors to the downwind states, including in Wisconsin and in Illinois. Minnesota's Boswell 3 and Boswell 4 coal plants would emit between 2021 and 2035 over 12,000 metric tons of NO_X pollution; the 2021-2035 cumulative air pollution emissions from Boswell 3 and Boswell 4 would cause almost $550 million of health impacts, including health impacts in

Illinois and in other downwind states, thus disproportionately impacting BIPOC people downwind. On the other hand… retiring early Boswell 3 by 2025 and retiring early Boswell 4 by 2030 would reduce adverse health impacts by approximately $200 million in Minnesota and in downwind states including in Wisconsin and in Illinois.

[F]or the proposed NTEC gas plant, which would be 20 percent owned by Minnesota Power, the Supplemental Environmental Assessment completed for that plant estimates that the new fossil fuel power plant would emit annually 1,564 tons of nitrogen oxides. Those emissions would be new ozone precursors emitted upwind of—and a health hazard for—populations living downwind in Wisconsin and downwind hundreds of miles into Illinois, at least."

Commenter (0543) writes that the EPA must adopt monitoring and enforcement approaches to ensure compliance, especially in fenceline communities, and prioritize protections for the most-exposed populations.

Commenter (0763) states that the cumulative impacts of ozone on the health of fenceline communities should be centered when considering how the proposed rule will impact upwind and downwind communities. Specifically, providing modeling tracking long-range ozone concentration changes in Black, Hispanic, linguistically isolated, and lower education attainment communities could fill information gaps that are found in the provided RIA. Currently, pollution reporting avenues under the TCEQ do not provide access to Spanish and other dominant languages in a state where over three million people speak English "less than very well" and polluters are expected to self-report.

Commenter (0277) describes the EJ considerations related to the proposed rule in the context of Missouri:

"St. Louis is located in the eastern part of Missouri and is a region that would be positively impacted by proposed regulation. According to the Missouri Census Data Center the total population of St. Louis is about 304,709 people. Compared to Missouri as a whole, St. Louis is a diverse area. The Census Data provides that the Black population in Missouri is 11.4 percent while in St. Louis, Black residents make up 48 percent of the city's population. Data gathered by the CDC shows that the average household income in St. Louis City is about $11,000 less than the State average. In addition, 20.4 percent of the city's residents live below the poverty line. These factors can lead to potential environmental justice issues.

Commenter (0277) continues, the neighborhoods in St. Louis that contain a majority of Black residents tend to have a high percentage of air pollution sources and subject the residents to a variety of health risks. The commenter believes these communities would benefit from the proposed regulation because it reduces the amount of pollution that already overburdens these communities. For example, compared to the rest of the United States, the Ozone levels in St. Louis City ranks in the eighty-seventh percentile and eighty-eighth percentile for PM 2.5. Due to the location of the neighborhoods in relation to the pollution sources, these residents are exposed to higher levels of pollution than other areas in the State and country.

According to the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard there is a larger percentage of minorities living within 5 km and 10 km of an affected

Electric Generating Unit. The commenter explains, the data shows that, when compared to the national reference groups, some population subgroups may experience slightly elevated seasonal average ozone concentrations. The regulatory options under consideration regarding ozone exposures do not pose any potential environmental justice concerns. In addition, the change in ozone concentration that would be a result of the new regulation does not show any evidence of increased environmental justice concerns. Therefore, the pollution reduction would have a positive effect on St. Louis.

Commenter (0277) continues, the other highlighted community is Sikeston, Missouri. Sikeston is in the southeastern part of our State. The United States Census Bureau estimates that 16,135 people live in Sikeston. The racial makeup of the city is 71.1 percent White, 24.1 percent Black, and the remaining population is made up of American Indian, Asian, or Native Hawaiian. Compared to the demographics of the entire State, Sikeston is also a diverse community like St. Louis. In fact, Sikeston has double the State's average of Black residents. The commenter stresses the degree of income variation is also diverse. However, some residents of the community are economically disadvantaged. A review of Sikeston's Census Data estimates that the median household income is almost $15,000 less than Missouri's median household income. In sum, the Sikeston community displays some of the indicators of a community more susceptible to environmental injustices.

Commenter (0277) states the residents of Sikeston live in close proximity to a coal-fired power plant. The Sikeston Power Station is approximately one mile west of the center of Sikeston. This power station is an electric generating coal-fired power plant. According to the EPA's Enforcement and Compliance History Online, the Sikeston Power Station emitted more than 1.8 million pounds of nitrogen oxides in 2020. Similar to the trends reported in the RIA, the communities living in close proximity to the Power Station are predominantly Black. The commenter explains, because of their proximity to the power plant, these residents are exposed to air pollution at higher rates. In fact, the EPA's EJScreen database reports that the western portion of the city is in the eighty-sixth percentile for Ozone and eighty-five percentile for PM 2.5 compared to the rest of the United States. The proposed regulation would have a positive effect on the Sikeston community by reducing several types of air emissions.

The commenter argues the proposed regulation could address existing disproportionate NO_X emissions in minority and economically disadvantaged communities in the state of Missouri. The proposed regulation could mitigate environmental justice concerns that affect communities like Sikeston. As reported in the RIA, regulating NO_X emissions to meet the obligations under the good neighbor provision may reduce NO_2 and $PM_{2.5}$. As previously noted, one of these pollutants is overwhelmingly present in the western portion of Sikeston. Reducing these two pollutants would have a positive effect for the communities living near the Sikeston Power Station. The commenter supports the proposed regulation for not only reducing NO_X emissions that contribute to nonattainment areas in other states, but also the positive effect it will have on communities living near coal-fired power plants."

Response:

The EPA recognizes that minority and low-income populations often bear an unequal burden of environmental harms and risks and continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

The EPA considers environmental justice impacts as required by Executive Order 12898, which directs federal agencies to avoid disproportionately high and adverse human health or environmental effects on low-income and minority populations. The EPA's responsibilities under E.O. 12898 are addressed in Section X.J of the preamble.

Consistent with the EPA's commitment to integrating environmental justice in the Agency's actions, and following the directives set forth in E.O. 12898, the Agency analyzed the impacts of this rulemaking on communities with environmental justice concerns. As described in Section VII of the preamble, the EPA expects the rulemaking to result in a reduction of NO_X emissions across all population groups, regardless of socioeconomic status. The emissions reductions achieved under this rule will help prevent premature deaths, reduce hospital and emergency room visits for people with asthma and other respiratory problems, help thousands of children and adults from missing school and work due to respiratory illness, and decrease asthma aggravation for thousands of Americans. This action's health benefits assessment and environmental justice (EJ) exposure assessment, including quantified health and climate benefits, are contained in Chapters 5 and 7 of the accompanying RIA, which is available in the docket for this rulemaking.

6.2 Tribal Consultation

Comments:

Commenters (0257, 0259, 0402) state that the EPA has not complied with its Tribal consultation obligations. Commenters acknowledge that the EPA hosted an EJ webinar, which is beneficial, but not sufficient as a national outreach strategy. Commenters point out that the EPA states that it plans to further consult with Tribal officials early in the process of developing the proposed rule, but this is impossible because the rule has already been developed. Commenters point to comments by the National Tribal Air Association (NTAA) that explain that if the EPA knew that it was proceeding with development of the proposed rule, it should have initiated consultation with Tribes at that time. Commenters request the following remedial actions by the EPA:

1. "Make a genuine effort to provide Tribes with any additional resources and assistance that they might require to engage in effective government-to government consultation.
2. Ensure that government-to-government consultation meetings with Indian Tribes result in meaningful dialogue rather than simply pro forma consultation.
3. Send a letter to each Tribal chairperson with copies provided to appropriate staff (*e.g.,* Tribal administrator, environmental manager) that asks each Indian Tribe how it would like to be consulted on the proposed rule. Providing copies to different individuals of authority within the Tribe will provide better assurances that the Tribe is clearly made aware of the proposed rule. Asking each tribe about how it would like to be consulted respects its individual sovereignty and Tribal cultures and helps to ensure that true government-to-government consultation occurs.

4. Provide assurances to Indian Tribes that the most senior-level EPA officials will be engaged in government-to-government consultation since they will likely be represented by their highest level officials such as Tribal chairpersons and/or council members; and
5. Provide adequate time to Indian Tribes to review and provide comments concerning the proposed rule.
6. Inform the National Tribal Caucus and Regional Tribal Operations Committees for a matter of this level of importance."

Commenters (0257, 0259, 0402) criticize the EPA's treatment of EJ and Tribal issues as a single category, stating:

"[W]hile environmental justice concerns may apply to many Tribal communities, there also needs to be recognition that Tribes are very distinct entities that preexist establishment of the United States. They possess authority that predates the U.S. Constitution regarding the governance of their own internal affairs. For these reasons, environmental justice is an important issue, but must never usurp Tribal sovereignty and self-determination. Further, environmental justice must never replace government-to-government consultation directly with Tribes. Any environmental justice actions must treat Tribes as sovereign nations with self-determination first and part of the environmental justice community second."

Response:

The EPA recognizes the strong connection many federally recognized tribes and indigenous peoples have to the environment and their past and present role in the protection and sustainability of the environment and public health. In recognition of Tribal sovereignty, the EPA established environmental justice principles to guide the EPA's efforts to work more effectively with federally recognized tribes and indigenous peoples in all areas of the United States to identify and address their environmental justice concerns.

The EPA takes seriously its commitment to honor tribal sovereignty and recognizes the importance of appropriate consultation with Tribal Nations, consistent with the federal government's trust responsibility to federally recognized tribes. In accordance with the 2009 and 2021 Presidential Memorandums and the EPA's 2011 Policy on Consultation and Coordination with Indian Tribes, the EPA conducted outreach and information sharing with tribal environmental staff both pre-proposal and post-proposal to ensure tribes had the opportunity to participate in the process. For pre-proposal outreach, the EPA held an informational webinar on October 26, 2021, and invited all federally recognized tribes to participate. The EPA provided questions in advance of the webinar for participants to consider. The questions assisted with the dialogue and helped inform the proposed rulemaking. The EPA also discussed the potential rulemaking on a monthly NTAA call and opened the docket pre-proposal to allow submission of comments for the EPA to consider during the development of the rule. After rule proposal, the EPA sent letters to tribal leaders and environmental staff offering consultation. These letters were also sent to the EPA's regional tribal contacts for widest dissemination. While no consultations were requested, Region 9 tribes requested, and the EPA held an informational webinar. To ensure there was sufficient time for the public to provide comments on the proposal, the EPA extended the public comment period to 60 days.

We continue to look for opportunities to increase our outreach to tribes during the rulemaking process and appreciate the feedback for our consideration.

6.3 Economic Impacts

Comments:

Commenters (0055, 0300, 0340, 0341, 0346, 0355, 0359, 0372, 0396, 0398, 0499, 0528, 0533, 0541, 0546) criticize the EPA's EJ analysis for failing to consider the economic impacts of the rule. Commenters also express doubt that the proposed rule will achieve meaningful emissions reductions as well as concerns that it will disproportionately harm EJ communities by causing higher prices and grid instability.

Commenter (0055) explains that in the West, coal plants are very important to the economy, and several of the potentially affected communities are rural and/or low income. Commenter writes that these areas will face severe economic hardship due to lost jobs and wages if units are forced to close as a result of the expedited timelines in the proposed rule. Commenter notes that President Biden has committed that U.S. coal communities will experience a "just transition" as the energy economy changes and states that without consideration of the above-mentioned topics, the proposed rule cannot be considered a "just transition" and does not "do right by the men and women who dug coal and built the nation." Commenter encourages the EPA to undertake a "meaningful public consultation and engagement process" with affected communities and citizens.

Commenter (0300) writes that the proposed rule will disproportionately affect lower-income, disadvantaged, and minority Mississippians by causing higher electricity costs and electrical grid instability. Commenter adds that the emissions reductions are "inconceivable," and the proposed rule will provide no "health and/or economic benefit."

Commenter (0341) writes, "For many units in Kentucky, the short timeframe for implementation will accelerate retirements and generation replacement costs for generating units that will increase consumer costs on an accelerated schedule. In addition, the dynamic budgeting approach using a single year's heat input as the basis for state budgets will limit utilities in Kentucky ability to respond to year-over-year load variations and thus increase consumer costs. These costs will be divided among all rate payers in a service area and could have significant economic impacts on states like Kentucky with a high rate of low-income residents and could disproportionately impacting disadvantaged communities."

Commenter (0355) cites a study by Energy Efficiency for All which found that rural households have a median energy burden of 4.4 percent, compared to the national average of 3.3 percent. Rural low-income households are even worse off, shouldering a median energy burden almost three times greater than the burden faced by their higher-income counterparts. Other rural residents hit particularly hard include the elderly, nonwhite, and renting households, and those living in multifamily or manufactured homes. The problem is most glaring in the East and Southeast. Poor people and people of color use much more electricity per square foot in their homes than white and more affluent people, resulting in households that can least afford it spending more on utilities. Commenter writes, “the price increases that will likely result if this proposal is finalized will further drive the current increase in inflation levels because of the integral role of energy in the national economy.”

Commenters (0340, 0346, 0409, 0541) express concerns about the proposed rule’s impacts on rural electric cooperatives. Commenters explain that rural electric cooperatives serve large, sparsely populated, lower-income residential areas, which are more expensive and less profitable than other utility sectors. Commenter (0346) states that due to these dynamics, 63 percent of rural electric cooperative members pay higher residential electric rates than customers of neighboring electric utilities and they are more vulnerable to rate increases. Commenters argue that the proposed rule will cause significant increases in electricity prices, which will be passed on to residents, thus constituting a failure to meet the federal government’s stated EJ goals by causing disproportionate burdens and failing to consider the “fair treatment” of citizens in upwind states.

Commenter (0396) asks the EPA to maintain its commitment to environmental justice by avoiding “the imposition of unnecessary requirements that are likely to close facilities that provide some of the best jobs in the state.” Commenter states that “marginal contributions to ozone concentrations in Texas” do not warrant “shuttering vital resources, further burdening an already struggling state population.”

Commenter (0499) states that the implementation of additional controls is currently estimated to exceed $1 billion in Louisiana alone, which will significantly impact its population, which has the fourth lowest median household income in the US and the second highest poverty rate.

Commenter (0346) criticizes the EPA’s EJ analysis in the proposed rule, writing:

“EPA did not consider the disproportionate economic impact of the Transport Rule on ratepayers within service areas that are in large part made up of minority and rural populations. This economic impact is of particular concern to electric cooperatives, like STEC. Electric cooperatives are unique because have a cost sensitive ratepayer base of rural, often economically disadvantaged [sic] communities, and agricultural users. As a result, cooperatives are required to serve reliable power over larger geographic areas with limited financial resources. To meet its customer and member obligations, STEC depends on coal-fired and natural gas generation sources.

Due to STEC’s reliance on coal and natural gas-fired generation sources and limited ability to shift generation to other sources, the significant costs associated with the emissions controls mandated under the proposed rule will be imposed directly on rural populations made up in large part of communities of color.

STEC, like other electric cooperatives, is a not-for-profit entity. Cooperatives have no investor equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. Consequently, STEC must ultimately pass along capital costs directly to their customers through increased rates. Because STEC serves areas with low population density, there are fewer customers to share in those costs. The ones who are there do so, even though they already spend more of their limited incomes on electricity than do comparable municipal-owned utility or investor-owned utility customers. That is yet another reason why STEC's members are disproportionately affected by the sorts of rate increases to which the CPP would give rise.

Given that the G&T cooperatives maintain only marginal cash reserves for unforeseen events and anticipated operating expenses, financing for many capital projects necessarily requires reliance on debt investors. The costs of borrowing, too, are necessarily passed on to cooperatives' members, who invariably pass them on to their consumers. Ultimately, then, it is STEC's members and their consumers who bear the cost of changes required by laws like the CAA and regulations promulgated under it. Thus, the requirement to install SCR and obtain emissions allowances in an extremely tight allowance market will result in substantial rate increases that will have direct impacts on its rate payers.

However, the impact of the additional costs on rate payers, a high percentage of which are people of color, low income, and unemployed were not even considered in the EPA's environmental justice analysis. As applied to STEC, this rule will mandate that people of color, low income, and unemployed Americans pay significant additional costs to produce negligible reduction in NO_X emissions in areas with significantly lower percentages of people of color and low income populations."

Commenter (0527) encourages the EPA to provide oversight and create accountability measures within states to ensure that the costs of compliance do not fall onto consumers. Commenter writes:

"We are currently experiencing record-high gas prices and energy costs that are drastically increasing the cost of living for most Americans. These high energy costs disproportionately impact low-income communities with less disposable income. While there are many factors at play that are fueling the increased cost of energy, such as the impacts of the COVID-19 pandemic and the Russian invasion of Ukraine, it is undeniable that oil and gas companies are capitalizing on this situation. While Americans suffer with home energy prices increasing between six percent to 16 percent over the past year, these companies have experienced record profits. Though the additional cost for energy under the proposed rule is estimated to be one percent, low-income communities cannot afford any additional costs. Within the current context of price gouging from oil and gas corporations that we currently face, the EPA must proactively plan for and work with policy makers to create mechanisms that penalize corporations who use the requirement of new standards to hyperinflate prices. The EPA can ensure that these new standards improve public health, while also ensuring energy affordability by working with states to track energy prices throughout the implementation of this rule. If companies increase their prices at or above one percent, we strongly encourage the EPA to work with policy makers within the House and Senate oversight committees to hold industries accountable."

Response:

For the final rule, we carefully considered the comments received on all aspects of the proposed rules. While our approach and methodology for establishing the final standards remained the same, we made several changes to make the final rules more flexible and cost-effective, address concerns with energy reliability, and cost, while fully preserving or improving the public health and environmental protection required by the CAA. These changes are discussed in more detail in the preamble to the final rule and in the other sections of this document.

The emissions reductions achieved under this will help prevent premature deaths, reduce hospital and emergency room visits for people with asthma and other respiratory problems, help thousands of children and adults from missing school and work due to respiratory illness, and decrease asthma aggravation for thousands of Americans. This action's health benefits assessment and environmental justice (EJ) exposure assessment, including quantified health and climate benefits, are contained in Chapter 7 of the RIA.

The EPA considered potential EJ concerns of this rulemaking. As with all EJ analyses, data limitations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics, environmental impacts, and more granular spatial resolutions that were not evaluated. This action's full EJ assessment is contained in Chapter 7 of the RIA.

In addition, the EPA estimated the change in the retail price of electricity. Any changes in average retail electricity prices at both the national and regional level are projected to be very small in 2023. In 2025, the EPA estimates that this rule will result in a one percent increase in national average retail electricity price, or by about 1.02 mills/kWh. Regional changes in electricity prices are available in Chapter 4 of the RIA.

Although not explicitly considered in our analysis of economic impacts of this rule in the RIA, funding from the Inflation Reduction Act will provide economic resources to assist in the larger energy transition that commenters have identified, lowering potential economic burdens on low-income and minority populations.

For more information on the estimated economic, small entity, and energy effects, please refer to the economic impact analysis for the final rule. The analysis is available in the RIA. The RIA describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

6.4 Trading Program

Comments:

Commenter (0510) expresses support for specific provisions of the rule that address EJ concerns. Previous versions of the NO_X trading rule resulted in a surplus of underpriced NO_X allowances that allowed sources to selectively turn off post-combustion controls. The following proposed additions to this rule will ensure the market is not flooded with excess allowances and that sources actually operate installed controls.

Optimization of existing emissions controls and the new daily backstop emissions rate for large coal units will provide added relief to overburdened and vulnerable communities. Nearly all EGUs included in an EPA analysis were found to be located within a day's transport distance of many potential environmental justice areas. In the past, incentives to control emissions around the clock were insufficient. Ensuring that these large EGUs refrain from simply "averaging out" single days of high emissions caused by nonoperation of control equipment will protect the health of local and downwind populations.

Commenter (0503) expresses support for the proposed mass cap and daily rate backstop as a "significant step to providing additional environmental protection for overburdened communities." Commenter notes that by requiring daily emissions rate limits, the communities in which polluting facilities are located experience "an immediate and significant reduction" in pollution exposure which can lead to a corresponding reduction in adverse health impacts. Requiring upwind pollution sources to comply with daily NO_X emissions rate limits provides an immediate benefit to local communities and for farther away downwind nonattainment areas.

Response:

Thank you for your comments.

Comments:

Commenter (0527) discussed ways in which the current allowance trading program fails to address EJ concerns from ozone pollution. While the commenter appreciates the new restrictions placed on emissions trading schemes– including daily rate limits, limitations to banking allowances, and tighter, annual adjustments to NO_X budgets– we fundamentally do not support such programs and the continuation of these systems is a key misstep in this proposed regulation.

Commenter (0527) explains cap-and-trade can create "pollution hotspots" or "sacrifice zones" that further burden marginalized communities. Environmental and climate justice groups have long fought against these programs in accordance with data that demonstrates that emissions trading negatively impacts or provides few benefits to disadvantaged communities. Continuing the practice of cap-and-trade primarily serves to benefit polluting industries, and "may lead to higher emissions" overall. In fact, the EPA is not statutorily required to allow interstate emissions trading. The Agency should require reductions in emissions from upwind states to prioritize public health and protect overburdened environmental justice communities downwind and living close to polluting power plants and industries, rather than enabling cost-savings for industry and the power sector. Cost-savings for industry compliance projected to be $15 billion cannot compare to $80 billion asthma costs the U.S. economy annually in medical expenses, lost productivity, and deaths."

Response:

The EPA's responsibilities under E.O. 12898 and environmental justice analytical considerations are addressed in Sections VII and X of the preamble.

The EPA anticipates that enhancements to the EGU emissions trading program will reduce the potential for pollution hot spots and will reduce ambient concentrations of pollution. This rule reflects the EPA's consideration of the science of ozone transport and set state emissions budgets to reduce significant contributions to ozone nonattainment and maintenance receptors (*i.e.*, the areas with the highest ozone levels); implementing air quality-assured trading; requiring any emissions above the level of the allocations to be offset by emissions decreases; and imposing penalties for sources that contribute to a state's exceedance of its budget plus variability limit. Backstop daily emissions rates on coal-fired EGUs with add-on controls will begin in 2024 to better ensure that controls are operated each day of the ozone season which further protects downwind communities.

In addition, it is important to note that nothing in this final rule allows sources to violate their title V permit or any other federal, state, or local emissions or air quality requirements.

The emissions reductions achieved under the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards will help prevent premature deaths, reduce hospital and emergency room visits for people with asthma and other respiratory problems, help thousands of children and adults from missing school and work due to respiratory illness, and decrease asthma aggravation for thousands of Americans. This action's health and risk assessments, including quantified health and climate benefits, are contained in Chapter 7 of the RIA. Further analyses regarding air quality improvements associated with this rule can be found in the Ozone Transport Policy Analysis Final Rule TSD.

Comments:

Commenter (0519) states that the EPA's approach is inconsistent with its own environmental justice screening tools and is unnecessary to protect these communities. Commenter explains first, the EPA cannot utilize environmental justice concerns to expand its authority under CAA section 110(a)(3)(D)(i)(I). The CAA's good neighbor provision limits the EPA's authority to eliminating emissions significantly contributing to downwind air quality problems. The EPA's daily backstop limit exceeds this authority by subjecting covered units to overcontrol, requiring additional emissions reductions beyond the EPA's chosen level of stringency.

Commenter (0519) continues, second, this approach is not consistent with the EPA' s emphasis on localized considerations and impacts in its assessment of environmental justice. By imposing a one-size-fits-all backstop emissions rate, the EPA ignores the specific challenges faced by individual communities and removes critical compliance flexibility for affected units. It is far more reasonable and appropriate for the EPA to instead assess environmental justice screen areas to see if trading under the proposed FIP is providing a problem on a finer, more individualized basis, consistent with the EPA's environmental justice guidance.

Response:

The EPA disagrees that the daily backstop rate exceeds the Agency's authority under the good neighbor provision of the CAA. See preamble Section V.D.4. *Over-Control Analysis.* Although the daily backstop rate may benefit environmental justice communities, it was not introduced specifically to address environmental justice concerns. See preamble Section VI.B.1.c.i *Unit-Specific Backstop Daily Emissions Rates.* Furthermore, for the final rule, the daily backstop emissions rate requirement is deferred for coal-fired EGUs that do not have add-on controls, providing affected units additional compliance flexibility. In analyzing the environmental justice impacts of this rule, the EPA did not find evidence that the final rule would exacerbate environmental justice concerns related to ozone and $PM_{2.5}$ in affected communities. This action’s full EJ assessment is contained in Chapter 7 of the RIA.

6.5 Stakeholder Outreach

Comment:

Commenter (0763) requests additional outreach to EJ communities regarding this rulemaking. Commenter does not feel adequately informed to provide comment on the potential impacts of parts of the proposed rulemaking, such as the emissions and trade allowances.

Response:

The EPA continues to look for opportunities to increase our outreach to communities with environmental justice concerns during the rulemaking process and appreciates the commenter’s feedback for consideration. To provide stakeholders with information about this rulemaking, the EPA held a pre-proposal outreach webinar in October 2021, and an informational webinar in March 2022 that included an overview of the proposal and information on the allowance trading program. The content presented during these webinars and additional supporting information is available on the EPA webpage dedicated to the rule (https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs) and in the docket for this rulemaking.

6.6 Distributional Analysis

Comments:

Commenter (0538) writes that the EPA should revise and expand its distributional analysis to better reflect the impacts of the proposed FIP on vulnerable subpopulations. Commenter elaborates on their suggested changes. The EPA’s baseline demographic proximity analysis indicates that Hispanic and Black people, as well as people below the poverty level and with less education, are more likely to live near affected sources compared to the national average and likewise are more likely to face higher ozone exposures. However, its distributional analysis focuses on how the reduction of NO_X from these sources will affect ozone concentrations for populations located downwind, rather than populations near the affected sources themselves.

Commenter (0538) adds the EPA notes that the goal of this action is to “require NO_X emissions reductions that will eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind areas.” However, this does not preclude the EPA from considering co-benefits for upwind areas—particularly here in its distributional analysis, where the EPA has already demonstrated significant environmental justice concerns exist for vulnerable subpopulations living near EGUs. In determining which regulatory alternative provides the highest distributional benefits, the EPA should include consideration of how the proposed FIP affects vulnerable populations located near affected sources.

Commenter (0538) writes that the EPA should revise and expand its distributional analysis to better reflect the impacts of the proposed FIP on vulnerable subpopulations. In the RIA, the EPA concludes that none of the regulatory alternatives under consideration will raise "meaningful EJ concerns." However, the EPA also notes that Hispanic, Asian, and Native American people as well as less educated people will face relatively smaller ozone concentration improvements as compared to the overall population. Given that the EPA also found that Hispanic, Asian, and Native American people are more likely to live in areas of high ozone concentration than any other group, the proportionally lower improvement in ozone concentration means that these already vulnerable populations may remain relatively worse off than other subpopulations as a result of the proposed FIP—and in fact, the proposed FIP may worsen the disparity in air quality for these vulnerable populations.

Commenter (0538) provides the example, imagine that Area X has a majority non-Hispanic White population and a baseline ozone concentration of 20 ppb. Nearby Area Y has a majority Native American population with ozone concentrations of 40 ppb—a concentration that is 2x as high as Area X. A hypothetical regulatory policy that reduces ozone concentration by five ppb in both area X and Y would actually worsen this inequality, as the majority-Native American Area Y would now face ozone concentrations that are 2.3x higher than the majority-White Area X (35ppb versus 15ppb). However, by the EPA's logic in the proposed FIP, this hypothetical example would not raise environmental justice concerns because ozone concentrations decrease for all populations. This turns the goal of distributional analysis on its head, as the EPA has not fully evaluated the relative distribution of benefits as compared to baseline conditions. A complete distributional analysis should show whether the benefits of reduced pollution primarily accrue to disadvantaged communities, or if these communities will continue to be disproportionally burdened by higher pollution.

Commenter (0538) argues the EPA should fully evaluate the relative distribution of air pollution impacts for all subpopulations, rather than simply concluding that the proposed FIP does not raise environmental justice concerns so long as each group experiences some reduction in pollution.

Commenter (0538) writes that the EPA should revise and expand its distributional analysis to better reflect the impacts of the proposed FIP on vulnerable subpopulations. Commenter states that the EPA should conduct its distributional analysis at a more granular geographic level to capture the heterogeneous air quality impacts within a given area. The EPA's current unit of analysis, 12 kilometers x 12 kilometers cells across the contiguous U.S., is roughly equivalent to the size of a medium-sized city such as Pittsburgh, Pennsylvania. Thus, the current aggregation level of the EPA's analysis misses all distributional impacts within the area of a medium-sized city, despite the potential for significant disparities at this scale.

Commenter (0538) continues, the EPA should improve the granularity to a finer scale, ideally one kilometer by one kilometer for dense urban areas. The EPA can use existing tools, like the Intervention Model for Air Pollution, which allows for this level of finer spatial resolution. At this scale, the EPA could better determine the impact of its regulation on the populations of interests, particularly within large urban areas where the majority of the U.S. population live, which can have significant variations in air quality. For example, using Intervention Model for

Air Pollution's more granular scale, the Agency could analyze the distributional impacts within neighborhoods rather than at a city level.

Commenter (0538) adds, the EPA should also disaggregate its analysis comparing the environmental justice impacts of its regulatory alternatives, which currently relies on state-level averages. As the EPA notes, "[a]ir quality improvements across demographic groups within individual states are variable." Thus, it is unclear why the EPA relies on this aggregate state-level data to conclude that none of the regulatory alternatives create environmental justice concerns. The EPA cannot properly compare the distributional outcomes of the regulatory alternatives under consideration without a disaggregated analysis breaking down the air quality impacts at a much smaller geographical scale.

The commenter states for more information on the importance of using a granular spatial scale in environmental justice and distributional analyses, see Policy Integrity's report, Making Regulations Fair: How Cost-Benefit Analysis Can Promote Equity and Advance Environmental Justice.

Commenter (0538) continues, in evaluating the overall costs and benefits of the proposed FIP, the EPA calculates expected reductions in NO_X, SO_2, CO2, and PM 2.5. However, in its distributional analysis, the EPA discusses reductions in CO2 and PM 2.5 only qualitatively, and does not discuss SO_2 at all. The Agency's quantitative analysis is limited to NO_X reductions and their accompanying impacts on ozone concentrations. For a proper evaluation of distributional impacts from the proposed FIP and the identified alternatives, the EPA should consider all relevant pollutants.

Commenter (0538) writes that the EPA should revise and expand its distributional analysis to better reflect the impacts of the proposed FIP on vulnerable subpopulations. Finally, the EPA calculates for each population of concern changes in ozone concentration resulting from the proposed FIP and the identified alternatives, but it fails to conduct statistical tests that show whether these changes in concentration are statistically different from zero. The EPA is also not consistent in what it considers "significant" for changes in ozone concentration. In its analysis to determine which industries are significant contributors to downwind pollution, the EPA uses 0.01 ppb as a "meaningful conservative breakpoint," to distinguish sources with a contribution of "greater than or equal to 0.01 ppb to at least 10 receptors." Conversely, in its distributional analysis, the EPA characterizes the expected reduction in ozone concentration for most receptors as being "less than 0.04 ppb" and describes any variance in reduction between populations as "very small" rather than quantifying it. Likewise, the Agency describes—without quantifying—the distribution of benefits between the regulatory alternatives under consideration as "reasonably similar." If the EPA determines that a contribution of 0.01 ppb is significant in distinguishing between sources, the Agency should then explain why changes smaller than 0.04 ppb are not considered significant in its distributional analysis.

The current discussion in the EPA's distributional analysis lacks sufficient data on statistical power, which is critical to the EPA's comparison of regulatory alternatives and for the EPA's analysis of which groups would benefit most from the proposed FIP.

Response:

The EPA finds that the change in disparities between various groups analyzed is negligible. Technical limitations prevent the EPA from analyzing EJ distributional ozone exposure impacts at a more highly resolved geographic scale. We note that we did not say at proposal that the changes at "receptors" were less than 0.04 ppb – that figure was related to the change in ozone concentration experienced by 90 percent of the overall reference population. *See* Proposal RIA at 7.4.2.2. The change in ozone levels at identified nonattainment and maintenance receptors under the final rule, on average, is 0.66 ppb. *See* Section V.D.3 of the preamble. These improvements in ozone levels will bring important air quality and health benefits to all demographic segments. Our observations in Chapter 7 of the RIA that the rule does not make a significant change is only in relation to existing disparities in pollutant exposure, not the overall improvement in air quality that this rule will deliver.

6.7 Other Comments

Comments:

Commenters (0527, 0757) state that waste incinerators should also be included in the proposed rule. They explain that nearly 80 percent of incinerators in the US are located in EJ communities, and between 67 percent and 83 percent of the twelve incinerators that emit the most nitrogen oxides, sulfur dioxide, lead, mercury, PM, and carbon monoxide are located in census tracts with primarily low-income residents and residents of color. Municipal Solid Waste Incinerators have also been found to have higher NO_X emissions than coal-fired power plants. Emissions from chemical recycling or advanced recycling plants that incinerate plastics are also an emergent public health concern, with most also sited in areas of low income and communities of color.

Response:

As discussed in Section V.B.3.a of the preamble, the EPA is including MWCs in this final rulemaking. More information on the screening assessment for MWCs can be found 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* that is available in the docket for this rulemaking.

7 Costs, Benefits, and Other Impacts of the Proposed Rule

7.1 Costs

7.1.1 The Proposed Rule's Expected Costs Are Appropriate

Comments:

Commenters (0261, 0265, 0318, 0367, 0402, 0506, 0733) support the benefits of the proposed rule and the anticipated costs.

Commenter (0277) believes that reducing health care costs and loss of life, the proposed rule would far outweigh the cost of compliance – articulated as $15 billion (2016$, 3 percent discount rate) each year over the period from 2023 to 2042.

Commenter (0367) states that for non-power plant sources, the commenter supports inclusion of major stationary sources in the emissions budgets. The commenter notes that by requiring control equipment costing up to $7,500 per ton, the EPA would impose control costs that are roughly comparable to, but lower than, costs for controls on power plants. The commenter provides that non-power plant sources have not been included in the most recent regional ozone transport rules, but in an earlier regional trading program, the NO_X SIP Call, the EPA found significant contribution from nonpower plant sources. According to the commenter, the EPA's analysis has reasonably identified available, cost-effective emissions reductions from these sources that can assist in reducing upwind significant contribution.

The commenter contends that in setting emissions budgets that include reductions in non-power plant sources' emissions, the EPA has reasonably relied on available data to determine the effective emissions reductions that can be achieved by these sources, even as it seeks to further refine its information. The commenter states that as the Wisconsin court held, scientific uncertainty or even administrative infeasibility would not justify declining to include these sources. The commenter provides that the EPA was not only allowed, but was required, to identify emissions reductions from non-power plant sources, and failure to do so would have been unreasonable and contrary to recent case law.

The commenter provides that emissions reductions from non-power plant sources are necessary to address upwind significant contribution, which persists through at least 2026, when the emissions budgets first account for reductions from these sources. The commenter notes that upwind states— and EPA, when promulgating FIPs—are required to eliminate, not just reduce, upwind significant contribution as expeditiously as practicable. The commenter states the especially when significant contribution persists long after downwind attainment deadlines, the EPA must regulate sources such as major upwind non-power plant stationary sources where it has reasonably determined that meaningful emissions reductions are available, and particularly where cost-effective controls for non-power plant sources, like those imposed on power plants, can achieve such reductions.

Additionally, the commenter notes that even though the emissions reductions achieved from regulating non-power plant sources are less than those achieved from regulating power plants, the reductions are meaningful, accounting for an additional average reduction of about 0.2 ppb at each nonattainment receptor in 2026. The commenter contends that the EPA can and must reasonably regulate them. The commenter provides that significant contribution is comprised of many relatively small contributions from sources in upwind states that combine to prevent timely attainment and interfere with maintenance of the ozone NAAQS in downwind areas such as the states. The commenter notes that therefore, to eliminate significant contribution impacting downwind states, the EPA must require emissions reductions from a variety of sources, including categories not currently regulated. The commenter states that the EPA has demonstrated that meaningful emissions reductions from non-power plant sources are available and necessary to eliminate significant contribution and has reasonably included such reductions in its formulation of emissions budgets for the covered states.

Response:

Thank you for your comments. The EPA notes that for non-EGU industries and emissions units, the Agency did not propose emissions budgets and did propose emissions limits. The final action includes emissions limits for non-EGU industries and emissions units.

Comment:

Commenter (0505) states the EPA's cost analysis does not accurately or appropriately account for the retrofit difficulty, pre-control baseline, and discount rate used to calculate annualized retrofit control costs. More specifically, the commenter points out that the SCR control cost effectiveness threshold appears to be based on assuming an uncontrolled baseline and applying that cost effectiveness in all cases, regardless of the starting level of control. This approach, according to the commenter, is unreliable and typically underestimates the true cost effectiveness of a control strategy. While the commenter admits that the EPA's cost effectiveness approach and assumptions may be valid for states that have implemented little or no control strategies in the past, they assert that it is not a valid approach but for states, like Texas, that have implemented substantial NO_X controls on new and existing combustion equipment through legislation, rulemaking, and permitting.

Response:

Comments on EGU and non-EGU cost analysis are addressed in Section V of the preamble and Sections 2.2 and 4 of this document. Regarding the commenter's concern on the use of different discount and inflation rates, the EPA notes that 1) inflation rates account for the change in the price of goods over time or alternately the change in the value of money over time; and 2) discount rates are used to calculate the net present value of a future stream of costs and benefits. While inflation rates and discount rates are similar concepts, they are distinct and therefore different values may be used. While a general inflation rate is used in some circumstances to convert between different year dollars, in some cases the EPA used the Handy-Whitman Steam Production Plant Index as it better represented the costs of SCR and SNCR retrofits on EGUs.

In the fleetwide analysis application of the retrofit cost tool, as described in the EGU NOx Mitigation Strategies Final Rule TSD, the EPA used a reasonable assumption for an "input" NO_X rate that depended on the type of unit being assessed. The EPA defines the term "input" NO_X rate, or "uncontrolled" NO_X rate to be the emissions rate of the unit following the combustion process including the effects of all existing combustion controls, measured after it has left the boiler, and where it would enter any post-combustion control equipment (if any). For units without existing post-combustion controls, this rate was assessed as the 2021 ozone season average rate. For units with existing post-combustion controls, for the input NOX rate, to identify an emissions rate when the unit's control was not operating, we identified each unit's maximum monthly emissions rate from the period 2009-2021. This was done to identify the emissions rate when the post-combustion control is not operating so that the EPA could calculate the average dollar per ton cost of retrofitting an SCR on an uncontrolled unit.

Regarding comments suggesting that the EPA should only account for incremental NOx reductions for units that may currently be operating an SNCR, we disagree. These emissions reductions would be fully replaced by installing a new SCR system (*i.e.*, an operator would not "add" an SCR control onto an existing SNCR system). In addition to this analysis, the EPA also conducted a separate analysis of coal-fired units with SNCR retrofitting an SCR that calculated the dollar per ton cost using only the incremental NO_X reduction (*i.e.*, only the NO_X reduction from reducing the emissions rate from that of an optimized SNCR to a newly retrofit SCR). This analysis is presented in the EGU NO_X Mitigation Strategies Final Rule TSD (and was also shown in the EGU NO_X Mitigation Strategies Proposed Rule TSD). That analysis found that such upgrades were still cost-effective. Comments regarding the Non-EGU Screening Assessment are addressed in Section 2.2 of this document.

Comments:

Commenter (0367) supports requiring installation of new post-combustion control equipment, particularly new SCR, where appropriate. The commenter states that power plants, including many coal plants and combustion turbines in the states, have adopted SCR or SNCR, which are highly effective at reducing NO_X emissions. The commenter provides that controls are also necessary in upwind states, because significant contribution from upwind states persists through 2026, the first ozone season when EPA has set emissions budgets to reflect installation of these controls across the fleet. The commenter contends that the EPA has reasonably determined that new SCR and SNCR on upwind sources lacking these controls will be necessary to assist with eliminating this ongoing significant contribution.

The commenter states that the Proposal recognizes that it is much more cost efficient for upwind states to implement additional controls at lower marginal costs than for downwind states to implement ever more stringent controls. The commenter provides that the costs of up to $11,000 per ton of NO_X removed for new SCRs and SNCRs are higher than the costs of near-term measures EPA is requiring in 2023 and 2024, but even these costs are comparable to or less than the marginal costs for additional controls in the downwind states that have long been burdened by excessive ozone pollution from upwind sources. The commenter notes that to the extent EPA considers cost in establishing levels of control stringency to set state-specific emissions budgets, it can do so reasonably only by accounting for the much more stringent and costly controls mandated in downwind states that require their sources to employ Reasonably Available Control Technology (RACT). The commenter contends that downwind states in the OTR, including Connecticut, New York, New Jersey, Massachusetts, and Delaware, are required to implement RACT state-wide, which entails a set of controls that, in many cases, go far beyond the Proposal's control stringency.

Additionally, the commenter provides that Connecticut's emissions control program for fuel-burning emissions sources of NO_X is based on a control stringency of $13,118 per ton of NO_X emissions reductions. The commenter states that likewise, New York's RACT requirements correspond to approximately $5,500 per ton of NO_X emissions reductions, well above the Proposed Rule's $1,800 per ton control stringency for the first few years of implementation. The commenter notes that New Jersey has also required controls that significantly exceed the Proposed Rule's 2026 $11,000 per ton control stringency, including controls for oil-fired boilers at up to $18,000 per ton of NO_X emissions reductions and SCR controls for natural gas turbines (compressor turbines) between $7,033 and $18,983 per ton of emissions reductions. The commenter provides that New Jersey's ozone season cost effectiveness for installing water injection on a high energy demand days unit is $44,000 per ton of NO_X removed.

Response:

Thank you for your comments. The downwind states' prior control installation and cost levels are considerations that inform the EPA's multi-factor test and analytics. See Preamble Section V.B for more discussion.

Regarding the statement that downwind states with ozone nonattainment or maintenance issues have imposed much more costly emissions controls on their sources as measured in dollars per ton, our analysis in this action recognizes this reality and calls for EGUs and other industries found to be impactful in linked upwind states to reach a level of emissions control that is roughly commensurate with these downwind requirements. While perfect parity among all upwind and downwind states is not possible, our four-step framework provides a reasonable approach to defining significant contribution for a regional-scale pollutant like ozone and will deliver meaningful air quality improvement through reductions in ozone at the identified receptors.

Comments:

Commenter (0506) notes that the EPA estimates the costs of the Proposed Rule will be $1.1 billion in 2026, using a 3 percent discount factor, while the monetized benefits - excluding monetized climate benefits - will be between $9.3 billion and $18 billion in that year. The commenter asserts that the monetized benefits far outweigh the costs, even without including the monetized climate benefits, and without considering non-monetized benefits. The commenter notes that climate benefits alone, in terms of GHG emissions reductions from this rule, will total $2.1 million in 2026.

Additionally, the commenter provides that at the time the Proposed Rule was finalized, the U.S. District Court for the Western District of Louisiana had enjoined EPA and other agencies from using the SC-GHG to quantify the benefits of GHG emissions reductions expected from a regulation. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, the commenter notes that the EPA's analysis of the costs and benefits of the Proposed Rule pursuant to Executive Order 12,866 did not include the benefits of GHG emissions reductions. The commenter states that the court's injunction was later lifted (Louisiana v. Biden, No. 22-30087, 2022 U.S. App. LEXIS 7589 (5th Cir. Mar. 16, 2022)), and EPA prepared an addendum to the RIA that uses the social cost of carbon (SC-CO2) to monetize the climate benefits associated with the carbon dioxide emissions reductions projected to occur from the Proposed Rule.

According to the commenter, the EPA's cost-benefit analysis for the final rule should include the SC-CO2, but as informational only. The commenter states that the benefits of the Proposed Rule clearly outweigh the costs, even without considering the additional large benefits associated with the reduction in greenhouse gas emissions. The commenter provides that there is no reason to expose the rule to potential interference if the courts should ultimately decide that the EPA should not use this particular metric in decision-making. Further, the commenter states that assessing the climate benefits of the Proposed Rule for informational purposes is consistent with OMB Circular A-4's guidance and Executive Order 12866 on regulatory analyses.

Response:

Thank you for your comments. The EPA includes climate-related benefits in the RIA for the final action. This is for informational purposes as a part of the overall benefit-cost analysis of the rule in the RIA and is not part of the record-based rationale for the rule, which implements requirements under CAA section 110(a)(2)(D)(i)(I) pertaining to the 2015 ozone NAAQS.

7.1.2 The Proposed Rule's Expected Costs Are Excessive

Comments:

Commenter (0289) provides that the EPA's RIA projects annualized costs for the proposed FIP for the entire country but does not include state specific or unit specific costs. The commenter contends that the EPA must provide an updated RIA, which must include state-specific costs, and must evaluate costs on a facility-specific basis. The commenter provides that without doing so, it shows that the EPA is ignoring the impact of its proposed FIP on states, citizens, and business across the country. Without this data, the commenter notes that states and facilities cannot even evaluate EPA's proposed cost estimates to determine whether they are accurate or not. The commenter also points out the issue of EPA's cost estimate for 2023, where it projects that 230 million dollars will be saved over the business-as-usual case. The commenter suggests that if businesses can save 230 million dollars without a regulation, they would do so because it makes economic sense. Further, the commenter states that the 8,000 tons of NO_X ozone season emissions reductions in 2023 that the proposed FIP would impose will not result in cost savings to generators or electricity rate payers in Missouri. The commenter contends that those reductions will cost tens of millions of dollars per year. According to the commenter, that means, if EPA's projections for costs in 2023 are correct, then states like Missouri will be paying tens of millions extra in energy costs, while other states that are likely closer to and contributing more to the ozone problems in downwind states will be saving money.

In addition, the commenter contends that the RIA does not evaluate remaining useful life of the sources on which the rule imposes costs. The commenter states that if the proposed FIP is finalized as proposed, there will undoubtedly be newly announced retirements of both EGUs and non-EGUs that cannot afford to install the controls needed to comply with the rule. The commenter notes that the EPA's RIA does not evaluate the cost of transmission upgrades and replacement electricity generation that will be needed to meet electricity demand as a result of the lost capacity that will result from the rule. For the first time in the last few decades, the commenter asserts, MISO is projecting capacity shortfalls to meet peak demand in the summer of 2022, and rolling blackouts and brownouts, which are extremely rare in the United States, are now a real possibility in the Midwest United States this year due to a lack of baseload capacity. The commenter states that the latest capacity auction in MISO's Midwest region cleared at over $300 per MW-day, whereas last year the price was approximately $5 per MW-day, which is a 6,000 percent increase. The commenter contends that the reason for this is that the energy transition to more and more renewables with fewer and fewer baseload plants is advancing more quickly than upgrades to the electricity grid are able to accommodate. The commenter states that with more baseload retirements, the situation will only get worse, and this proposed rule is very likely to result in exactly that. The commenter notes the EPA must analyze the impact that more baseload retirements will have on society and the economy, including the increased risk of blackouts and brownouts in electricity regions and what cost those types of events may impose.

Response:

EPA modeling takes into account expected demand, generating availability, target reserve margins, and transmission limitations (and expansion cost). See preamble Section VI.B.1.d for a response to comments regarding reliability. *See also* Chapter 4 of the RIA.

Comments:

In addition, commenter (0289) states that the EPA does not evaluate the impact of potential job losses that will occur when facilities and power plants shutdown due to the newly proposed requirements, nor does EPA project the impact on costs for residents to heat their homes in light of the newly proposed requirements on the natural gas transportation industry. The commenter contends that the EPA must consider and provide an analysis of what the impact on retail natural gas prices will be for the various regions of the country that are impacted by the rule. The commenter notes that without this information, there is no opportunity for the public to weigh the projected costs and benefits of the proposed rule. The commenter provides that without a clear understanding of the actual costs that this proposed rule will toll on Missouri and other American citizens, it is clear the proposed rule is being rushed through the rulemaking process and has a real possibility of resulting in severe and damaging unintended consequences.

Commenter (0554) is concerned that the EPA has not taken all the necessary considerations into account to deal with the impacts of the Proposed Rule and to facilitate a just and orderly outcome. The cost, timing and retrofit requirements of the proposed rule will result in reliability concerns while forcing regressive investments. The commenter also states the EPA did not give adequate consideration to its impacts on the communities that will be affected by accelerated coal-unit retirements. Finally, the commenter notes the proposed rule threatens to impose a one-size-fits-all approach onto this complex program rather than working with the western states to find the best solution, which must be tailored to the conditions and resources in each state.

The commenter contends that the EPA must update its RIA to show exactly what the projected costs are for every facility that will incur new costs as a result of the rule. The commenter states that the EPA then needs to re-propose the rule so that facilities can have a chance to explain whether EPA's projected costs are reasonable. Additionally, the commenter provides that the EPA should consider remaining life of existing facilities, and where the new requirements will likely result in shutdowns and stranded assets, what will be the economic impact to communities where those shutdowns take place. The commenter notes that it appears that in developing this proposed rule, the area where EPA spent the least amount of resources is in considering the actual costs and impact the proposed rule will impose. According to the commenter, this is not an effective planning strategy and requests EPA to update the RIA so that the projected costs are transparent and comprehensive.

Response:

The EPA does not agree that we are ignoring the impacts of the rule on citizens and businesses across the country. The EPA prepared the *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard* (RIA). Chapter 4 of the RIA includes information on changes in fuel prices for fuels used to generate electricity and on changes in electricity prices. Chapter 6 of the RIA discusses potential EGU-related employment-related effects of the rule; we note that the rule will likely result in construction-related job increases (in addition to possible reductions in employment in some cases), because it will require construction labor to install emissions controls or may incentivize a shift to cleaner production technologies.

The EPA disagrees that it must know precisely what the projected costs are for each affected facility before it can finalize this rule. This rule establishes emissions reduction obligations to eliminate significant contribution based entirely on existing NO_X control technologies that are already in widespread use across all affected industries. The rule does not mandate the shutdown or retirement of any source. Cost determinations relevant to the Step 3 analysis in this rule are discussed in Section V of the preamble and Section 4 (The EPA's Quantification of Upwind State NO_X Emissions Reduction Potential to Reduce Interstate Ozone Transport).

Comments:

Commenter (0394) states that the EPA underestimated the cost per ton of the NO_X emissions reductions to be achieved through control technology by orders of magnitude due in part to EPA's decision to assign a 10-year life for recovery of SCR capital costs, which has the effect of lowering the incurred cost-per-ton of NO_X removed through the use of that technology. In reality, some units will cease operations before reaching the assumed 10-year life. A 5-year life for recovery of capital costs is more realistic and may double the incurred cost-per-ton. According to the commenter, the EPA underestimates the incurred cost per ton using a 10-year life for recovery, and the overestimation is compounded when a 5-year life for recovery is considered. Specifically, as explained in the Technical Report:

- The retrofit of SCR to coal units incurs a cost for the median unit in the population that ranges from $20,250 per ton for operation at the 56 percent capacity factor, escalating to approximately $28,000 per ton for units at the 90 percent population.
- The retrofit of SCR to distillate oil/gas-fired units – which would apply to 35 units under the Proposed Rule – incurs a cost for the median unit that ranges from $11,000 per ton for operation at the 56 percent capacity factor and a 10-year remaining lifetime, to over $66,000 per ton for operation at the 2021 capacity factor and 5- year remaining lifetime.
- SNCR retrofit as EPA proposes – to coal-fired units of 100 MW generating capacity or less – captures only six units. The incurred cost for the median unit ranges from $12,645 per ton to more than $100,000 per ton, which reflects operation at the 2021 capacity factor and 5-year remaining lifetime.

The commenter contends that SCR retrofit costs exceed EPA's estimate incurred by the median unit of SCR retrofit of $15,500/ton for coal at the 56 percent capacity factor and for SNCR for the population of boilers less than 100 MW of $10,800/ton for coal application. As a result, the EPA's judgments in the Proposed Rule regarding emissions reductions that can be achieved cost effectively are incorrect.

Additionally, the commenter states that while the assumptions and analysis used to support the Proposed Rule are problematic, they do support EPA's decision to continue excluding stationary, fossil fuel-fired boilers serving a generator with nameplate capacity of 25 megawatts electric or less producing electricity for sale from the proposal. Retrofitting NO_X controls are still neither cost effective nor technically feasible for existing intermittently operated small boilers. Regulating small boilers under this proposed rulemaking could disproportionately increase the burden on small entities with minimal environmental benefit. The commenter contends that this outcome would run counter to EPA's decision to "significantly reduce the burden on small entities by reducing the number of affected small entity-owned units" under the Regulatory Flexibility Act obligations to minimize disproportionate small entity impacts.

Response:

See the EGU NOx Mitigation Final Rule TSD and preamble Section V.B for EPA's response and sensitivity analysis regarding its representative book life assumption.

Comments:

Commenter (0401) provides that the general criteria noted in the proposal for applying controls to iron and steel mill units is an annual NO_X emissions rate of 100 tons with a cost effectiveness of $7,500 per ton of NO_X controlled. The commenter notes that the EPA RACT/BACT/LAER Clearinghouse does not identify any control technology for cupola NO_X emissions, and the cost per ton of NO_X emissions controlled would be significantly more than $7,500 per ton as discussed below. According to the commenter, steel production facility melt rates are generally an order of magnitude higher than those at foundries, and so would the NO_X emissions be higher, meaning very few foundries would have the capacity to exceed the 100-ton NO_X emissions threshold cited in the proposed rule. The commenter states that, in short, the comparison between iron and steel mills and iron and steel foundries is not equal, and therefore, foundries should not be included in the proposed rule.

Additionally, the commenter states that it appears the inclusion of iron and steel foundries is based on one reference noted in the TSD, a 2011 study by RTI that cited the technical feasibility of applying SCR to foundry cupolas. The commenter states that this study was not included in the rule docket, and therefore, could not be correctly evaluated. The commenter provides that the use of SCR is not technically feasible for a foundry cupola as SCR require consistent temperature, flow rates, and concentrations that do not exist for most cupolas. The commenter is not aware of any control applications of SCR on foundry cupolas. In addition, the commenter notes that the 2011 RTI study estimated the cost of applying SCR control to foundry cupolas of $10,000 per ton of NO_X emissions controlled, which is well above the $7,500 cost effectiveness threshold used in the rule development.

Response:

The EPA is not finalizing emissions limits related to blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and EAFs as proposed at this time. The only emissions units within Iron and Steel Mills and Ferroalloy Manufacturing that the EPA is finalizing requirements for are reheat furnaces and boilers. These comments are further responded to in Section VI.C.3 of the preamble.

Comment:

Commenter (0435) states the proposal is just one in a suite of planned regulatory actions that will add new burdens and costs to the electricity and industrial sectors alike, raising costs for ratepayers, consumers, and state and local governments. The EPA projects that the proposal will eliminate 11,200 jobs nationwide in operating and maintenance activities and fuel extraction jobs in 2025 and reduce future coal industry jobs by 1,000 in 2028. The Agency was unable to calculate job losses in the industrial sectors affected by the proposal, which means these job loss figures are, if anything, underestimates. The RIA also shows that this rule will crush power generation from coal by 38 trillion kilowatt hours - or a decrease of 7.77 percent by 2025 - at a time when the electricity supply is already facing shortfalls in the near term. Those significant impacts on jobs and power generation will inevitability decrease grid reliability and reduce access to cheap, affordable fuel, leaving ratepayers on the hook for higher prices. This includes citizens of West Virginia, who will be forced to pay five percent more on their electric bills in 2025 according to the EPA's analysis. Furthermore, the "benefits" the EPA cites are based on opaque and questionable estimates, "monetize[ed] climate benefits" associated with the proposed rule using the SC-GHG. The EPA claims in a separate "'technical memorandum" the proposed rule will save billions of dollars by avoiding certain impacts of climate change. The memorandum heavily relies on decisions made by the unaccountable "lnteragency Working Group on the Social Cost of Greenhouse Gases" (IWG), which has met behind closed doors with no meaningful public input and has continually avoided responding to valid Congressional oversight requests. This lack of transparency and accountability call into question the seriousness and credibility of the SC-GHGs.

Response:

The EPA prepared a reasonable analysis of economic effects and presented those in the Regulatory Impact Analysis accompanying the proposal. The RIA reflects updates to this analysis. Power sector effects are discussed in Chapter 4 and labor impacts are discussed in Section 6.2. The commenter does not provide additional information to support some of their claims related to additional job losses, decrease in grid reliability, and lack of transparency associated with SC-GHGs. The presentation of monetized climate benefits is for informational purposes as a part of the overall benefit-cost analysis of the rule in the RIA and is not part of the record-based rationale for the rule, which implements requirements under CAA section 110(a)(2)(D)(i)(I) pertaining to the 2015 ozone NAAQS.

Comment:

Commenter (0557) states the costs of the proposed generation loss are staggering and underestimated by the EPA. This loss of generation will impact Virginia's economy and competitive edge. In response to the proposal, NO_X allocations required to emit NO_X for EGUs have substantially increased in cost. As of June 15, 2022, the price is now over $30,000/allowance.

Response:

First, in regard to the 2022 allowance price, the allowance price has dropped by more than 50% from the level noted by commenter. Second, the commenter doesn't demonstrate that the 2022 price was solely driven by the proposal and not other market factors at the time (e.g., natural gas price volatility). Tables 4.15 through 4.17 in the RIA highlight EPA's finding that the rule would result in 1% or less increase in retail electricity prices in Virginia. Finally, the rule's emissions limits are derived off continued generation at historical levels (with mitigation measures in place), not any proposed generation loss. The EPA prepared a reasonable analysis of economic effects and presented those in the Regulatory Impact Analysis accompanying the proposal. The RIA reflects updates to this analysis. Power sector effects are discussed in Chapter 4. The allowance prices are based on supply and demand in the market and can change over time in response to market conditions and regulatory policy changes.

7.1.3 Costs Will Not Be Recoverable

Comments:

Commenter (0355) states that the EPA performed a "cost benefit" analysis that overestimates the benefits, fails to account for loss of electric reliability and widespread economic costs of this proposed rule, and as such, it is a severely flawed and inadequate analysis.

The commenter contends that the proposed rules will cause premature retirement and reductions of operations of coal and gas units; units that are needed to keep industries running and electricity provided to businesses and residences, including during peak demand periods and weather emergencies. The commenter states that the units identified by the EPA that would be affected by the proposed rules cannot be replaced by the 2026 period where the NO_X budgets fall dramatically. Additionally, the commenter notes that the EPA has provided no basis for the assumption that the identified at-risk generating units can be retrofitted by 2026 or that it would be economical to do so.

The commenter states that the costs of those retrofits are huge, and some of the identified units are slated for retirement within a few years after the 2026 implementation date, long before the EPA assumed 15-year period, thus making those retrofit investments potentially uneconomic and imprudent. Furthermore, the commenter provides that it is not clear that the supply chain can accommodate the products and services needed in the required time frame to install the retrofits, should the decision be made to do so. The commenter maintains that what is clear is that the affected utilities will seek to include the enormous costs of any retrofits or replacement capacity in utility rates, rates that are already facing upward pressures from rising fuel costs, new investments in transmission and other infrastructure due to the integration of renewables, and costs associated with the repair and replacement of transmission and distribution facilities due to the ever-increasing frequency and intensity of weather events. The commenter states that while the impact of higher utility bills harms everyone, they also disproportionately impact the under-the-poverty-line residential customers that the FIP states it is intended to aid. According to the commenter, the proposed rule needs to balance any identifiable environmental benefits against the reliability and economic problems it will create for the electric systems and customers.

Additionally, the commenter provides that the EPA's cost assessment on the cost effectiveness of SCR retrofits does not address several critical factors. First, the commenter states that the EPA's cost analysis improperly assumes that any SCR installed would be in-service for at least 15 years. The commenter provides that given the age of many of the units identified for such retrofits, this is an unsupported and unreasonable assumption. The commenter notes that the EPA's cost analysis fails to consider existing public and enforceable retirement dates for some units identified for SCR retrofits. The commenter also states that the EPA's cost analysis is inadequate without considering the impact of the SCR retrofit on those units. As such, the commenter contends that the EPA erroneously concludes that SCR retrofits would be cost-effective for the identified units even though many of these units have remaining lives less than EPA's assumed 15 years (beyond 2026). The commenter notes that the costs of the retrofits would likely not be prudent or economic for units that are close to retirement age. According to the commenter, there are nearly 5000 MW of affected capacity owned by Entergy in MISO South scheduled to operate beyond 2026 but scheduled to retire years before the 15-year time period assumed by the EPA in its retrofit analysis. The commenter states that the proposal does not provide any flexibility for the operation of units with relatively short remaining lives and that the EPA proposed rule should be amended to allow these units to continue to operate without SCR retrofit at least until their scheduled retirement dates.

Furthermore, the commenter contends that the EPA's cost analysis is flawed because EPA failed to consider delays due to materials shortages and cost escalations resulting from the current and ongoing supply chain problems. The commenter states that the EPA has not considered or addressed the competition for SCR expertise, raw materials, and other resources that would arise if numerous generators seek to simultaneously install SCRs to meet their respective obligations under this rule. Additionally, the commenter notes that the EPA also failed to incorporate any consideration of rising, non-transitory inflation, particularly as related to materials and fuel needed to build and transport the SCR retrofits. According to the commenter, were EPA to consider all of these additional cost factors in its analysis, the findings are likely to show that the costs associated with the SCR retrofit requirements in the rule are significantly higher than projected and not cost-effective.

The commenter also notes that the EPA's proposal would reduce the EGU's NO_X emissions budgets for Arkansas, Louisiana, Mississippi, Texas and 21 other states starting with the 2023 ozone season with more significant reductions in the 2026 ozone season. The commenter states that the EPA's proposed reduction is based on a presumption that coal and higher-emitting oil and gas-fired generating units will install expensive SCR NO_X emissions controls and place those controls in-service prior to the 2026 ozone season (May 1 – September 30). The commenter provides that the EPA has identified a total of over 50 generating units for these pollution control retrofits by 2026 in these four states, totaling over 26,000 MW of capacity.

According to the commenter, these required retrofits will be costly to all of the Louisiana Commission jurisdictional EGUs. The commenter contends that if a utility installs the SCR technology mandated by the proposed rule, it would seek recovery of those costs from ratepayers. The commenter states that of the MISO South generating units identified by the EPA for SCR retrofits, a total of 37 are owned and/or operated by Louisiana EGUs, for a total impact on approximately 14,800 MW of capacity. The commenter provides that Entergy is the largest supplier of electricity in Louisiana and has 15 units identified by the EPA for SCR retrofits and that all of Entergy's units are located in MISO South with approximately 9,370 MW of total unit capacity impacted by the proposed rule. The commenter expects that these SCR retrofits will cost hundreds of millions of dollars.

Commenter (0420) believes that the proposed rule, as written, will increase the price of energy and may result in the destabilization of the electric grid – which will would impact the nation’s economy and national security. In the case of Utah residents, the commenter suggests that families are already struggling financially, and the impact of higher electric prices would further eroding their economic security. The commenter briefly describes the makeup of Utah’s economy; the stat’s mining industry is estimated to contribute more than $6.2 billion to the gross domestic product (GDP). According to the commenter, Utah’s mining industry plays an important role in nation’s national security – the state produces 8 of the 35 nonfuel minerals or minerals groups categorized by the USGS as economic or national security (and hosts 20 more critical minerals), and is one of only two lithium-producing states in the U.S. Additionally, the commenter notes that Utah also producer copper – which is vital in the energy transition as it is used not only in electrical distribution but also as a manufacturing component in windmills, solar cells, electric vehicles, and energy storage. The commenter strongly feels that the proposed rule, if not modified, will undoubtedly be harmful to the Utah mining industry. The commenter implies that the state’s ability to provide reliable, low costs energy is largely a result of the state’s reliance on coal production (comprising more than 60 percent of the electricity generations in the state, employing more than 1300 people, generates tax revenue for the state, etc.).

Commenter (0434) discloses that they oversee the wholesale power market in the ERCOT region, ensuring generators are paid market-determined prices for the energy and ancillary services they provide while charging power retailers for power consumed (pursuant to its authority under Texas law). The commenter states that the cost of building new generating units is borne entirely by private investors, nor can the commenter impose such a requirement. According to the commenter, the price that generators are paid for energy produced and the price that power retailers are charged for energy consumed are determined every five minutes based on the supply and demand on the system.

Commenter (0407) overarching concern is the potential increase in cost of utility services for ratepayers, particularly for the states of Mississippi, and stresses that they need more time to determine what that increased cost will be; adding that additional information may be requested from the Agency to make a reasonably accurate cost determination. The commenter also questions EPA's authority to oversee, what has been predominately managed by states. The commenter underscores the point, in the case Mississippi, affordable, reliable electricity is the lifeblood of Mississippi's economy.

Commenter (0411) assert that the cost, under the current market and supply chains issues, to install the SCR equipment necessary to meet the Proposed Rule's requirements will be substantial, costs which the commenter suggests will be transferred to rates and ultimately paid by consumers.

Commenter (0375) proclaims, whether units in a utility's fleet run or do not run is determined by economic dispatch and operational constraints, and later adds that all other things being equal (particularly demand), a reduction in supply will result in an increase in price. The commenter states that the citizens of their state (Arkansas) are struggling with energy bills that have skyrocketed upwards during the last 18 months. The commenter claims that the proposed FIP leaves the Arkansas with a Hobson's choice of ether retiring generation units in an already supply-constrained market or spending hundreds of millions of dollars in compliance costs that will be passed on to ratepayers. The commenter asserts that regardless of the decision the result will be significant cost increases for consumers who are already struggling because of high energy costs.

Commenter (0375) states that energy costs are driving record inflation, and according to the commenter, the price increases disproportionately impact lower income Americans. The commenter adds that the state of Arkansas is ranked 48th in per capita income; thus, increasing energy costs are likely negatively impacting the quality of life in Arkansas. The commenter defines economic dispatch (as defined by the Energy Policy Act of 2005) and provides a brief explanation of the term, including examples. The commenter recognizes the efforts made by the Biden Administration to decreasing energy costs for households, including in rural, Tribal, and disadvantaged communities.

Commenter (0382) express their concerns that the proposed rule is rushed and will further stress the nation's power grid, by exacerbating the reliability, affordability, and resilience of the electricity supplied to homes and industries. The commenter adds that the mandate to develop or invest in expensive control equipment, under the current market conditions, will severely impact the manufacturing industry's ability to compete and will drive away valuable American manufacturing jobs to countries whose air pollution track records fall far short of the United States.

Commenter (0351) insist that only source of revenue available to pay the significant costs associated with SCR installation is through rate increases. The commenter explains that, given the short remaining life of Sherco 3 (after the 2026 deadline for SCR installation) over which to recover the SCR costs before the unit's retirement, the cost impact on members and their customers would be untenable. The commenter concludes that the only option under the Proposed Rule, is to reduce operation of Sherco 3 during the ozone season to keep emissions below the budgeted allotment, with potentially massive economic impact.

Response:

Comments on grid reliability and changes in the final rule for EGUs that are responsive to such concerns, are addressed in Section VI.B of the preamble. See also the Reserve Margins TSD in the docket for this action and Section 10.4 of this document. Economic effects of the rule, including energy prices and other projected power sector effects, are presented in the final rule RIA. As summarized in Section 1 of this document, the scope and total costs of this rule are comparable to prior interstate transport rules. These rules have been successfully implemented to eliminate significant contribution under the good neighbor provision for prior NAAQS without deleterious effects on the operation or reliability of the electric power sector. The requirements established for non-EGU industrial sources in this rule, as with EGUs, are based on widely-available, proven NO_X control technologies that are already in place on many sources in these sectors throughout the country.

Comments:

Commenter (0363) submits that the EPA's analysis is incomplete. The commenter contends that the EPA's analysis is based on market conditions that do not exist. The commenter states that the cost of reagents has skyrocketed. The commenter provides that supply chains that are necessary to install NO_X controls have been disrupted. Additionally, the commenter states that the EPA's proposed compliance methods are flawed. The commenter notes that generation shifting will exacerbate the financial impact of compliance on municipal utilities. The commenter states that the cost to install NO_X controls on generators slated for retirement cannot reasonably be recovered. The commenter notes that the EPA should afford the state of Arkansas an opportunity to submit a revised SIP prior to adoption of the proposed FIP. Last, the commenter encourages EPA to identify and consider small government entities that will be directly and substantially affected by the proposed FIP, such as the municipal utilities in Arkansas.

Commenter (0364) states they hold minority interests in White Bluff (ORIS ID 6009) and Independence (ORIS ID 6641). The commenter contends that even though the proposed FIP includes a list of proposed NO_X control strategies, the commenter will have little ability to determine which strategy is employed at White Bluff or Independence. The commenter provides that despite having little control over methods of compliance, City Water & Light will bear significant cost and risk related to implementation of the proposed FIP.

The commenter provides they also own three single-cycle natural gas powered EGUs collectively identified as “City Water & Light – City of Jonesboro" (ORIS ID 56505) (“Local Gas EGUs”). The commenter states that the Local Gas EGUs each have nameplate ratings below 75 MW (and true generating capacity less than 50 MW). The commenter notes that like other small simple-cycle natural gas EGUs, these units are expensive to operate but provide a fast ramp capability to support reliability during times of peak electricity consumption. The commenter contends that while the commenter has not yet performed an in-depth analysis of the cost to install SCR devices on the Local Gas EGUs, the commenter is not convinced that the capital and operational costs could reasonably be recovered in the limited periods when the Local Gas EGUs are operational. The commenter requests the EPA to exempt these units from regulation. The commenter states that the proposed FIP exempts coal steam units with less than 100 MW of capacity and all EGUs with less than 25 MW of generating capacity. Moreover, the commenter asserts that operating the Local Gas EGUs as peak response units produces less NO_X emissions than operating exempt generators as baseload units. To illustrate, the commenter states that because the proposed FIP exempts generators of every type smaller than 25 MW, it should likewise exempt generators of every type with capacity of 50 MW that are operated at a 50percent capacity factor. The commenter states that the EPA should resolve this conflict by further defining its exemption to include capacity and hours of operation. The commenter notes that this would allow units that are larger than 25 MW to operate for peak response while maintaining an exemption from the FIP. The commenter submits that such a rule would further the purposes of the Regulatory Flexibility Act and Unfunded Mandates Reform Act.

Commenters (0404, 0536) note that the EPA evaluated the costs and benefits of capital expenditures used to reduce NO_X emissions over 20 years (2023-2042). However, the commenter states that the White Bluff and Independence EGUs are subject to agreed orders that will cause the permanent cessation of all coal combustion by December 31, 2028 and December 31, 2030, respectively. According to the commenter, for White Bluff and Independence, the EPA should have evaluated costs and benefits of compliance in light of this shortened operational life. More specifically, commenter contends that the cost of compliance should include full cost recovery of capital expenses prior to the mandated retirement date and the benefit of compliance should exclude emissions reductions after the mandated retirement date. As such, the commenter recommends that White Bluff and Independence should be excluded from regulation under the proposed FIP, as should any EGU that agrees to cease operation before the end of 2030.

Commenter (0411) states that Sherburne County Unit 3 NO_X rates are already low due to the installation of low NO_X burners and separated overfire air . The commenter notes that the reductions achieved through the installation of an SCR will have a larger cost per ton removed than EPA estimated due to the fact that the unit will retire by the end of 2030. The commenter provides that installing an SCR on Sherburne County Unit 3 will not be cost effective. As stated in a 2022 response to a request by the North Dakota Public Service Commission (Case No. PU-20-441), the commenter noted that the minimum capital cost estimate for the installation of an SCR on Sherburne County Unit 3 is at least $150 million based on a 2020, pre-pandemic estimate that was escalated for inflation but not vendor price increases and global logistics impacts. The commenter believes EPA should create an exception for units scheduled to retire before the date in which the installation of a control device is deemed cost recoverable since the cost per ton removed on these units will be artificially high due to the short time period available to recover the costs. As such, the commenter asserts EPA should provide a consistent allowance allocation for these units until they retire and should not apply the backstop rate to these units.

Response:

These comments are addressed elsewhere in the record. Compliance with UMRA and RFA is addressed in the preamble. The Agency does not agree that it would be appropriate to devise further, more complicated exemptions from the rule's requirements for relatively small sources than is already provided for.

7.2 Benefits

7.2.1 The Proposed Rule's Expected Benefits are Appropriate

Comments:

Commenter (0261) states that the EPA's cost/benefit analysis of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards clearly shows that benefits far exceed costs, even though benefits are admittedly greater than reported. The commenter recommends consideration of some of the factors and statistics to follow to provide a more complete estimate of benefits in future regulation proposals. The commenter suggests incorporating the cost of premature mortality into the cost to benefit analyses of ozone precursors (PM, NO_X, ROG, VOC). The commenter provides that in 2018, 8.7 million people suffered premature mortality from fabric filter (FF) industry PM emissions. The commenter notes that a 2021 study estimated 10.2 million. Additionally, the commenter states that estimates of the number of annual premature deaths from FF PM in the US range from 335,000 and 355,000. According to the commenter, 340,000 multiplied by the value of a statistical life in the US ($10,000,000) is $3.4 trillion annually.

The commenter also states that combustion of FF and biomass emits about one dozen toxics. The commenter provides that many of these toxics are also GHGs, which are the foremost cause of climate change. The commenter notes that CO2, NO_2, CH_4, and Black carbon are common co-pollutants from each of the stationary sources targeted by this rule, specifying that although PM usually remains airborne for a few hours, wind can keep it aloft for weeks and carry it for hundreds of miles.

The commenter ascertains that an estimate of the death toll from climate change, 150,000 annually, is a very conservative estimate because cause-of-death records rarely mention air pollution. The commenter states that there is a high probability that premature mortality from climate change, as well as toxic co-pollutants, will continue to increase as long as FF combustion continues. The commenter contends that between 2030 and 2050, over 250,000 deaths per year are projected to be caused by weather extremes.

Furthermore, the commenter provides that the costs of climate change are referred to as Social Cost of Carbon. According to the commenter, the discount rate that best incorporates intergenerational effects is zero, and that no amount of funds spent in future years can reverse the damage from climate change this year. The commenter states the EPA should use a zero percent discount and post the SCC of NO_2, CH_4, and CO2 per MT in documents for this ruling and post annual updates on the EPA website. The commenter also provides that the average annual cost for medical care of those with chronic cardiovascular disorders is $16,000.

Commenter (0265) states that one aspect of this regulation not included in this docket but of relevance is the potential for the provision to lower the cost of healthcare expenditure that is attributed to air pollution. The commenter provides that in a 2020 report the estimated yearly cost of smog pollution is $7.9 billion and is attributable to 795 premature deaths, 4,150 respiratory-related hospitalizations, 485 asthma-related E.R. visits 365,468 other outpatient encounters in a year. The commenter notes that in a healthcare cost-benefit analysis, researchers found that scenarios where Ozone reduction is prioritized yield less expenditure than in scenarios with multiple pollutant models. According to the commenter, this means that while reducing all pollution is better for health outcomes in general, measures to reduce Ozone yield more efficient and less costly results. Moreover, these healthcare costs associated with exposure to Ozone and other pollutants are projected only to magnify in the coming decades due to the compounding health effects of climate change. The immense health and economic burden associated with Ozone pollution, which is only bound to increase in the era of climate change, necessitates the implementation and reinforcement of timely, targeted air quality regulatory actions.

Commenter (0402) asserts that these health benefits are extremely important, beyond any dollar value that could be placed on them and are sufficient justification to finalize the Proposed Rule. The commenter also believes these numbers under-count numerous other benefits from the Proposed Rule, including billions of dollars of climate benefits and environmental benefits. The commenter supports the Proposed Rule for the health and environmental benefits that it will provide, particularly for Tribal individuals that are disproportionately impacted by exposure to ozone partly due to the disproportionate incidence of asthma, hypertension, and diabetes in their communities, and urges the EPA to finalize and implement the Proposed Rule in the strongest form that the science justifies.

Commenters (0259, 0277, 0388, 0402, 0498) were pleased to see the strong levels of protections included in this proposal. The commenters state that as EPA has noted in its release, by 2026, the proposal will provide up to $18 billion in annual benefits for the United States. and is forecasted to prevent up to 1,000 premature deaths, avoid 2,000 to 2,400 hospital and emergency room visits, prevent 1.3 million cases of aggravated asthma every year, and 470,000 school absence days. The commenters note that emergency room visits with a child suffering an asthma attack can be terrifying, and we want to state again how grateful we are for the work EPA is doing to help prevent these hospital visits.

Commenters (0257, 0259) support the Proposed Rule for the health and environmental benefits that it will provide, particularly for Tribal individuals that are disproportionately impacted by exposure to ozone partly due to the disproportionate incidence of asthma, hypertension, and diabetes in their communities, and urges the EPA to finalize and implement the Proposed Rule in the strongest form that the science justifies.

Response:

Thank you for your comments. The EPA recognizes that the proposed rule is likely to also yield positive benefits associated with reducing pollutants other than ozone, $PM_{2.5}$, or CO2 (*e.g.*, direct exposure to SO_2, NO_2). Limited time, resource, and data limitations prevented us from characterizing the human health benefits associated with reducing direct exposure to SO_2 and NO_2 emissions. The Technical Support Document (TSD) for the 2022 PM NAAQS Reconsideration Proposal RIA, Estimating $PM_{2.5}$ - and Ozone-Attributable Health Benefits describes fully the Agency's approach for quantifying the number and value of estimated air pollution-related impacts. This document includes the rationale for selecting health endpoints to quantify; the demographic, health and economic data used; modeling assumptions; and our techniques for quantifying uncertainty.

In addition, data, resource, and methodological limitations prevented the EPA from monetizing ecosystem effects and visibility impairment associated with ozone and $PM_{2.5}$, as well as benefits from reductions in other pollutants, such as water effluents. We qualitatively discuss these unquantified benefits in Chapter 5 of the "Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard."

7.2.2 Expected Benefits are Undercounted

Comment:

Commenter (0538) states the proposed FIP's expected benefits greatly outweigh its expected costs. The EPA estimates that, between 2023 and 2043, the monetized criteria pollutant-related benefits of the proposed FIP will exceed its costs by $220 billion. And that already massive sum does not account for numerous unquantified health and environmental benefits of criteria pollutant reduction or for $670 million in annual climate co-benefits that will also result from the proposed FIP. The commenter notes CO2 reductions should also be considered as a benefit.

Response:

Thank you for your comment.

7.2.3 Benefits are Not Substantial and Meaningful

Comments:

Commenter (0323) states that the proposed rule is premised on the assumption that it would achieve 3.7 times the air quality improvement upon which the Revised CSAPR Update was based, but at a cost that would be 60 times the cost of the Revised CSAPR Update.

Commenter (0668) considers the proposed FIP unlawful "overcontrol." Specifically, the commenter notes there is minimal downwind air quality improvement expected from the proposed FIP comes with a sticker price of $22 billion, as projected by the EPA. The commenter states that, on average, the EPA's modeling, which itself is flawed, projects an improvement in air quality at the downwind nonattainment and maintenance receptors that Texas is linked to of only 0.06 ppb in 2023 for a cost of over $4.5 million, conservatively considering only costs associated with reductions from Texas—a cost of over $77 billion per ppb. Additionally, the commenter provides that even with significantly more stringent budgets and EPA's imposition of costly control technologies, the projected improvement in air quality from EGUs at the receptors Texas is linked to for 2026 is just 0.15 ppb for a cost of nearly $190 million, similarly considering only costs associated with reductions from Texas—a cost of over $1.2 trillion per ppb.

Additionally, the commenter states that the EPA errs by relying on co-benefits to justify the costs of its proposed FIP. The commenter notes that in EPA's own projection, less than 15 percent of the benefits identified in 2026 come from high day ozone exposure and instead, $8.1 billion of EPA's projected $9.3 billion in benefits in 2026 come from benefits expected to occur due to the simultaneous reduction in PM emissions. According to the commenter, the EPA cannot rely principally on PM benefits to justify its backstop ozone action, nor can EPA point to coincident climate benefits to justify its action, as EPA seeks to do in its Regulatory Impact Analysis. The commenter contends that the EPA's FIP authority is limited to ensuring states take required steps to control interstate transport of ozone, and EPA must justify its action based on ozone benefits alone.

Furthermore, the commenter asserts that although it is true that the EPA may determine what is cost-effective for purposes of defining "significant contribution," the Supreme Court has been critical when EPA oversteps its rulemaking authority by imposing significant costs for essentially no benefit. The commenter states that in opting to reiterate its four-step methodology, the EPA has an overarching obligation to ensure that its costs for controls have a meaningful impact on downwind ozone attainment. The commenter quotes, "EPA cannot require a state [to undertake significant costs] to reduce its output of pollution" by an amount virtually irrelevant to downwind-state ozone attainment, and EPA cannot rely on co-benefits unrelated to the basis for this rulemaking to justify EPA's costs. The commenter contends that approach imposes "costly overregulation unnecessary to, indeed in conflict with, the good neighbor provision's goal of attainment[,]"and constitutes overcontrol.

Commenter (0322) provides that as proposed, the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards has caused significant uncertainty in the impacted Group 3 allowance market. The commenter states that the market instability makes resource and compliance planning difficult. The commenter notes that the Group 3 allowances have increased from hundreds of dollars per ton (prior to the revised Cross-State Air Pollution Rule [CSAPR] rule in 2021 impacting the 2021 and 2022 seasons) to over $20,000 per ton of NO_X since the rule was proposed. The commenter provides that the EPA's own estimate for SCR installation is at $10,000 -$11,000 per ton. The commenter notes that SCR installation costs for units in Kentucky can range dramatically based on life of facility and capacity factor. According to the commenter, SCR cost per ton of NO_X removed can easily range from $10,000 to $70,000 based on life of facility, size of the unit and capacity factor, complicating resource planning. The commenter contends that this cost comes without meaningful improvements. The commenter states that the EPA's own analysis the proposed rule, if finalized, would result in a cost of $22 Billion at a three percent discount rate. The commenter provides that the EPA seeks to justify this cost by suggesting that this cost would result in "meaningful" improvements in air quality. To the contrary, the commenter states that in connection with the implementation of a National Ambient Air Quality Standard of 70 ppb ozone, the EPA's own analysis (87 Fed. Reg. 20097) shows the following air quality improvement from the four categories of controls involved – falling short of "meaningful" improvement:

- Existing EGU controls in 2023 -- 0.07 ppb
- New EGU controls/Gen. shifting in 2026 -- 0.36 ppb
- Non-EGU (Tier 1) 0.18 ppb Non-EGU (Tier 2) -- 0.04 ppb
- Total -- 0.64 ppb

The commenter is very concerned with the proposed rule's disconnect between energy supply, environmental compliance, and economic development in Kentucky. According to the commenter, Kentucky needs to remain competitive with surrounding states for new jobs, economic development, and low-cost energy. In addition, the commenter states that this proposed rule would result in a capacity shortfall of over 3,600 MW of capacity in Kentucky and poses concerns for electricity availability, affordability, reliability, and economic development load growth as early as 2026. Commenter (0550) states the EPA's cost analysis for its $11,000/ton cost threshold fails to take into account the disproportionate costs that would be imposed on units retiring in the near-term.

Response:

The EPA disagrees with the commenter's statements about the Agency relying on co-benefits to justify the proposed action. The statutory basis for this action is established through the analysis set forth in the preamble applying the 4-step interstate transport framework to address good neighbor obligations for the 2015 ozone NAAQS. Nonetheless, the projected reductions in other pollutants are real emissions reductions attributable to the requirements of this rule that the Agency discloses to the public through the RIA. In addition, as shown in Tables 5-4 and 5-5 of the *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, depending on which ozone exposure risk estimate is used to estimate the ozone-related benefits, the ozone-only benefits are larger than the PM benefits.

Commenters are not correct to imply that the rule's air quality benefits, even limited to the monetized benefits of ozone reductions, do not exceed the estimated cost of the rule -- see Tables VIII-5 and VIII-7 in the preamble. The improvements in ozone levels at identified downwind receptors are not trivial. See Section V.D of the preamble.

See Section IV of the preamble for further discussion of the air quality impacts from upwind states on downwind receptors and Section V.D of the preamble for discussion of both overcontrol considerations and an assessment of the improved air quality at downwind receptors available from the identified reductions.

Adjustments in trading program enhancements in the final rule are discussed in Section VI.B of the preamble and elsewhere in this document.

Comment:

Commenter (0538) states that the EPA estimates that its proposal will only lead to three receptors improving in attainment status in 2023 and only six receptors improving in attainment status in 2026. In other words, only three percent and six percent of the receptors that will be out of attainment in 2023 and 2026 (respectively) will change attainment status as a consequence of the proposed FIP. Accordingly, while the EPA's proposal represents a significant initial step, additional efforts to bring polluted areas into attainment will still be needed.

Response:

The purpose of this rule is to eliminate significant contribution pursuant to CAA section 110(a)(2)(D)(i)(I), not necessarily to bring downwind receptors into attainment. The Agency recognizes that additional measures may be needed to ultimately attain and maintain the 2015 ozone NAAQS throughout all areas of the country.

7.3 Other Impacts of the Proposed Rule

7.3.1 Proposed Rule Will Force EGU and Non-EGU Shutdowns

Comments:

Commenter (0261) states that it may be more economical for a business to shut down dirty stationary sources and replace each with a clean energy source. The commenter contends that construction of a solar or wind power plant is less expensive than construction of a fossil-fueled power plant and annual maintenance is lower. According to the commenter, the construction, installation, and maintenance costs of each PC add up and increase the price of products for consumers, which may decrease demand and sales volume.

The commenter provides that clean energy, *e.g.*, wind, geothermal, and solar, have significantly lower lifecycle emissions in Scopes 1, 2, and 3 than dirty energy. The commenter notes that green cement and steel plants are in operation that have a carbon intensity 40 percent lower than conventional cement and steel plants. The commenter contends that preventing emissions will have significantly higher social benefits than filtering out part of it. The commenter states that the most effective (and pricey) wet scrubbers remove up to 70 percent of PM emitted from smokestacks, however 30 percent is still emitted. The commenter provides that smokestack carbon capture equipment increases net CO_2 emissions over the lifecycle (while decreasing efficiency and increasing energy cost) and that there are no commercially available PCs for some kinds of pollutants. The commenter suggests that businesses should be given an option of replacement as a way of meeting attainment requirements. The commenter states that as dirty energy and products are replaced with clean, the EPA would be burdened with less regulation and could focus on other emissions sources (*e.g.*, mobile) and the cumulative value of benefits to society would rise. Additionally, the commenter states that the EPA should declare long-term plans for new regulations over the upcoming five or ten years, *e.g.*, 2025 CH_4, 2027 HFCs, 2029 PM, etc. to enable businesses to do the math and compare the cumulative costs of attainment via PCs versus attainment by replacement.

Response:

Thank you for your comments. The purpose of this rule is not to shut down any EGU or industrial facilities but to establish emissions control requirements based on available NO_X mitigation technologies to eliminate significant contribution for the 2015 ozone NAAQS.

Comments:

Commenter (0264) is concerned that dozens of coal units will be shut down because SCR retrofits are not economic due to site-specific engineering or other considerations. The commenter provides that the EPA's Regulatory Impact Analysis shows that 15percent of coal capacity, 23,000 Megawatts, would be retired prematurely by 2025 under the proposed rule. The commenter asserts that these unit shutdowns would translate to many thousands of unionized job losses in the coal mining, electric generation, and transport sectors, and are far in excess of any prior EPA projections of plant shutdowns resulting from implementation of a CAA rulemaking. For example, the commenter provides that the EPA projected a total of just 4,700 MW of coal capacity retirements under the 2011 MATS rule.

The commenter does not read the CAA, or its "good neighbor" provisions, as authorizing EPA to shut down roughly 100 electric generating units in neighboring states to achieve a fractional ozone reduction of one tenth of a ppb or less in downwind areas. The commenter contends that Congress did not intend the "good neighbor" provision as a means for upwind states to inflict severe economic harms on downwind states through the closure of major industrial facilities. The commenter recommends EPA take a more measured approach to defining control obligations for sources that are not yet equipped with state-of-the-art controls, thereby reducing the extent of premature retirements projected for this rule. The commenter notes that the history of the Clean Act clearly shows that Congress intended state-of-the-art controls to be applied to new sources through NSPS, and to existing sources within nonattainment areas through Lowest Achievable Emission Rate limits for pollutants contributing to nonattainment.

Commenter (0271) states that this rule means that the ERCOT, MISO & SPP power supply will experience premature closure of 35,806 MW of essential dispatchable generation in the next four years (which means that 37 percent of the SPP coal generation will be gone by 2030).

Commenter (0329) states that since 2002, Minnesota has closed no less than 17 municipal and investor-owned coal fired boilers greater than 25 MW and has invested in upgraded SO_2, NO_X and PM controls on remaining coal fired EGUs such that all currently operating EGUs (Sherburne County, AS King, Boswell) have at least state of the art combustion controls. The commenter notes that one operating unit has SNCR, while two have SCRs operating year-round, all of which have or will soon have federally enforceable closure dates.

The commenter contends that the FIP does not consider the unreasonable cost impacts of compliance by the remaining coal-fired power plants that are already scheduled for retirement. For example, the commenter provides that Xcel Energy's Sherburne Generating Plant Unit 3 (Sherco 3) is scheduled for retirement in 2030. The commenter states that Sherco 3's owners have estimated compliance costs of more than $100 million for a new SCR. According to the commenter, installing SCR would therefore be cost prohibitive for a plant that is slated to operate no more than five years after compliance is required in 2026.

Additionally, the commenter notes that the option of upgrading a large coal unit's pollution control equipment to reduce NO_X pollution and then delaying its retirement to allow the recovery of costs of installing the controls will result in increases in other pollutants, such as CO_2, which would jeopardize progress toward state and federal greenhouse gas reduction goals.

The commenter states that the restrictions in the proposed NO_X allowance trading program appear to make remaining in operation and acquiring allowances an unreliable approach. The commenter contends that this is because either option - purchasing excess NO_X allowances or curtailing operations - present significant cost risks. The commenter states that if allowances are to be purchased, their cost and availability would be unknown, in part due to the proposed FIP "dynamic budgeting" process. Furthermore, the commenter provides that if the operations must be curtailed during the ozone season that means the utilities' loads would be unhedged, leaving ratepayers exposed to market pricing at a time when MISO's energy and capacity markets are likely to be significantly short with resulting price volatility. The commenter states that having large units technically in-service but off-line due to lack of allowances has the potential to create reliability issues.

Commenter (0329) states that the rule assumes 15 years for SCR payback at coal EGUs. The commenter contends that in Minnesota, even if utilities could install equipment by 2026 (unlikely), they would only be able to use the equipment for 4-14 years given enforceable shutdown dates. The commenter provides that these timelines will be even shorter in practice given the time needed to plan, permit and install new control equipment. The commenter states that the emissions benefits of control equipment are similarly overstated for EGUs approaching retirement.

Response:

These comments are addressed in Section V and VI.B of the preamble and Chapters 4 and 5 of this document, and related TSDs. The EPA's projections of the economic effects of the rule are presented in the final rule RIA, and to the extent comments make claims that conflict with these projections, the EPA disagrees with those claims.

7.3.2 Proposed Rule Will Hinder the Economy

Comments:

Commenters (0300, 0329, 0380, 0340, 0359, 0399, 0509, 0513, 0668) state that the rule will result in shutdowns, adverse impacts to non-EGUs, and nationwide loss of jobs. At least one commenter (0509) believes that the EPA should withdraw its proposed rule. Commenter (0300) states that the implementation of the proposed FIP is not only injurious to Mississippians as a result of impacts on the United States' energy sector but on various other essential industry sectors as well. The commenter asserts that these needless restrictions on industrial sources will inevitably shift production outside the United States to countries with much less restrictive emissions controls than currently in place in the United States resulting in greater international pollution and transport, cause costs of essential goods and services to rise, and cause the loss of American jobs.

Commenter (0340) states that the EPA's requirement for control devices on non-EGU processes and equipment ensures that any new unit constructed in one of the 23 "Group 3 States" is also subject to the restrictions. The commenter stipulates that this additional requirement puts those states at a significant economic disadvantage. According to the commenter EPA is effectively making economic policy for states, choosing which states will enjoy increased economic growth and potential high paying jobs, and ensuring that the "Group 3" states will not.

The commenter contends that by including the implementation of daily backstop emissions rates for both EGUs and non-EGUs in the proposed rule, the EPA is restricting economic development and potential job growth in Kentucky. The commenter states that facilities that would be subject to the emissions controls and daily backstop rates proposed in this rule would be unlikely to consider Kentucky a viable location, instead potentially choosing to locate in a state that is not subject to the proposed rule.

As such, the commenter ascertains that this proposed rule punishes manufacturing states like Kentucky. The commenter provides that low-cost electricity is an incentive for industries looking to expand and has provided Kentucky with over $11 billion in investments and new jobs, including two new electric vehicle battery plants. The commenter notes that in a time when more emphasis is being placed on American independence from reliance on other countries for goods, this rule inhibits the ability of manufacturing states to be competitive in attracting new businesses. Given the implication of potential, similar future rules, that may include other states, the commenter is concerned that companies may not even choose to locate in a non-FIP state but choose a different country for their business.

Response:

Thank you for your comments. In Chapter 6 of *the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, the EPA included a discussion of the changes in employment in the electric generating and related industries. The EPA did not include a discussion of changes in employment in the non-EGU industries because of data limitations.

Comment:

Commenter (0329) contends that Minnesota has achieved significant criteria pollutant and greenhouse gas emissions reductions from EGUs and has committed to 100 percent carbon-free energy by 2040. The commenter states that the proposed Plan is disrupting long standing plans by affecting spinning reserve EGUs that provided reliability around renewable investments. The commenter provides that the new equipment requirements in 2026 and beyond also have the potential to spur new investment in coal EGUs, the opposite of Minnesota and EPA's stated climate and overall air pollution goals.

Response:

Minnesota is not linked to downwind nonattainment or maintenance receptors in 2026 in the final rule modeling, and thus no additional post-combustion controls are assumed, mooting much of the comment. How the rule accounts for power-sector transition and reliability issues are addressed in Section VI.B of the preamble.

Comment:

Commenter (0359) states that inclusion in this proposed transport rule will require much more stringent NO_X standards on industrial sources than would otherwise be required in many areas of the country. The commenter notes that some of the proposed NO_X limitations are more stringent than NSPS requirements under 40 CFR 60. The commenter provides that some NSPS for the industrial units subject to the proposed FIP do not regulate NO_X at all. Therefore, the commenter contends that being part of this proposed transport rule will place West Virginia at a significant disadvantage when competing for new industry and economic development with other states that are not subject to the proposed FIP.

Additionally, the commenter provides that the cost-benefit analysis overestimates the benefits of this rulemaking while grossly underestimating the costs. According to the commenter, the EPA in its cost-benefit analysis relies on benefits associated with the reductions in PM, in addition to ozone reductions. The commenter states that the EPA drastically underestimated the costs associated with the non-EGU controls.

Response:

Thank you for your comments. NSPS under Section 111(b) apply only to new and modified sources, not existing sources. The objective of the proposal under CAA section 110(a)(2)(D)(i)(I) is to eliminate significant contribution to nonattainment or interference with maintenance in other states. The EPA concluded that reductions in ongoing NO_X emissions from existing sources are needed to eliminate significant contribution.

The EPA disagrees with the commenter's statements about the Agency relying on co-benefits to justify the proposed action. The statutory basis for this action is established through the analysis set forth in the preamble applying the four-step interstate transport framework to address good neighbor obligations for the 2015 ozone NAAQS. The Agency is required by executive order to disclose to the public through the RIA projected reductions in other pollutants that are attributable to the requirements of this rule. In addition, as shown in Tables 5-4 and 5-5 of the *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, depending on which ozone exposure risk estimate is used to estimate the ozone-related benefits, the ozone-only benefits are larger than the PM benefits.

Comment:

Commenter (0380) states that the current proposal represents a dramatic departure from the cooperative history between EPA and the commenter. The commenter contends that without any communication with or input from the regulated Transmission and Storage (T&S) industry, the 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. The commenter considers this proposal to be based on a number of unfounded assumptions, including:

- The costs to retrofit this many engines will be significantly higher than EPA assumes. The commenter states that their 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 tpy 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.

COVID-19According to the commenter (0380), the consequences of the proposed rule will affect far more than the T&S sector. The commenter states that citizens and businesses rely on natural gas providers to heat their homes, cook their food, and run their businesses. The commenter explains 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. The commenter contends that 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.

Response:

The final rule provides for emissions averaging for engines in the pipeline transportation of natural gas industry, which we estimate could reduce the number of engines needing emissions controls to around 905. The rule also provides for case-by-case extensions of time for installing controls based on a showing of necessity. In the RIA, we estimate the total compliance cost for the engines in the pipeline transportation of natural gas industry to be $385 million annually (2016$), which is lower than the $900 million figure indicated by commenter. In our final rule 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*, we document how we estimated the number of engines and related emissions reductions covered by this rule; the estimated NO_X reductions are approximately 32,000 ozone season tons. Section V of the preamble establishes why these pollution control measures are appropriate to eliminate significant contribution for the 2015 ozone NAAQS. We do not believe the rule will have the broader negative economic effects that the commenter states and note that the rule does not affect the ability of the natural gas industry or FERC to ensure the delivery of adequate natural gas supplies to consumers.

Comment:

Commenter (0399) urges EPA to carefully consider the costs and benefits of the proposed requirements for the large industries, including the technological and economic feasibility of implementing controls to reach the identified nitrogen oxide (NO_X) emissions limits. The commenter recommends that the EPA consider the overall downwind reductions in NO_X from these requirements on particular facilities and industries. The commenter provides that to date, the EPA declined to publish requirements for industrial sources under the Cross-State Air Pollution Rule because the analyses on emissions showed the lack and uncertainty of the economic feasibility. The commenter asserts that it is still extremely costly and challenging for these industries to meet the level of emissions reductions that the EPA has estimated.

The commenter contends that the EPA should also avoid finalizing a rule with a timeline and emissions limits that would cause facilities to close and lay off workers due to unreasonable current high costs for control technology. The commenter states that the industries in question are trade exposed and must compete in a global market where cost pressures are significant, particularly given the current global economic changes in recent years from the COVID-19 pandemic to Russia's invasion of Ukraine.

Response:

Thank you for your comments. In Chapter 6 of *the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, the EPA included a discussion of the changes in employment in the electric generating and related industries. The EPA did not include a discussion of changes in employment in the non-EGU industries because of data limitations. Also, because of timing and data limitations, the EPA was not able to conduct economy-wide modeling. See Section 4.6 (Consideration of Volatile Organic Compound (VOC) Emissions or Other Pollutants).

Comment:

Commenter (0513) states that the EPA's decision to regulate cement kilns under the proposed FIP will significantly affect every aspect of the commenter's business— including long-term business planning and the day-to-day operation of its facilities. According to the commenter, the proposed FIP exceeds EPA's authority under the CAA and creates a substantial risk of significant and irreparable harm to the commenter's business and its customers by subjecting cement kilns to overcontrol, failing to provide any flexibility mechanism for these units, and applying an unlawful "one size fits all" approach to emissions limits across all impacted states.

Response:

Thank you for your comments. The EPA received comments and information through the public comment process after the proposal, specifically related to the cement and concrete products manufacturing industry. The final rule reflects changes from proposal and establishes emissions limits for cement kilns based on widely available emissions control technology for these source types.

Comment:

Commenter (0668) states that, in the West, coal plants are very important to the local economy as well as surrounding economies. The commenter provides that several of the potentially affected communities are rural, have significantly lower income populations and or low economic diversity. The commenter contends that the area will face hardship if units are forced to close on the expedited timelines stated in the Proposed Rule. The commenter notes that the welfare of the potentially affected communities that rely on these plants needs to be considered in EPA's decision making and timeline to avoid undue economic hardship. The commenter indicates that Pacificorp operates five units that directly employ hundreds of people and provide millions of dollars of taxes to the state of Utah and local governments. The commenter contends that the Utah units are extremely important to local economics surrounding the power plants. The commenter also notes that Hunter Power Plant directly employs about 186 people. and the Huntington Power Plant employs about 136. Additionally, the commenter states that thousands of other people are employed by and depend on mining and other power related industries. The commenter states that Emery and Carbon County are among the least economically diverse counties in the state and rely on the power industry and power plants for a significant portion of their tax and employment base. The commenter provides that PacifiCorp paid $22.6 million in property taxes to Emery County in 2021 which represents 68 percent of the County's total property tax revenues. According to the commenter, these revenues provide crucial funding for the Emery County Sheriff's Office, county government operations and the Emery County School District.

Furthermore, the commenter states that wages for plant workers are higher than overall industrial workforce, and a unit closure would have a significant impact on wages earned in the surrounding communities. The commenter estimates that the early retirement of a single unit at the Hunter Power Plant would result in approximately 20-25 percent employee reduction. The commenter also provides that any unit retirement would have broader impacts to associated industry jobs and local businesses serving the plants and communities. The commenter asserts that because the region relies so heavily on PacifiCorp's Utah units and associated mining and industry services, it is especially important to balance local interests, efficiencies, economics, and impacts while pursuing strategies to decrease environmental impacts and grow a cleaner power system.

In addition, the commenter references the Coal County Study, which explains "These two counties form a regional economy, with a shared commuter shed, shared industries and commuter spending patterns. Together, these counties face challenges with changing economic circumstances from declining coal production and the future closures of power plants." The commenter states that the report finds time is a critical factor to diversify the local economies and address the expected employment decline in the natural resource/coal sector. Additionally, the commenter notes that the welfare of the affected communities, which is intertwined with and dependent upon the presence of the plants and the need to ensure them a just transition are important factors that the EPA must consider as part of its obligation under the CAA and administrative rule making.

Response:

Thank you for your comments. In Chapter 6 of *the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, the EPA included a discussion of the changes in employment in the electric generating and related industries. The EPA did not include a discussion of changes in employment in the non-EGU industries because of data limitation.

7.3.3 Proposed Rule Will Transfer Costs to Utility Customers

Comments:

Commenters (0355, 0364, 0375, 0407, 0409, 0412, 0420, 0499, 0529, 0707) expect the cost of the proposed rule to be passed to consumers through utility rates. At least one commenter (0707) proclaims that electric utilities in their states (West Virginia) have no trouble recovering their environmental compliance costs through electric rates, thanks to the pro-coal state regulatory policies.

Commenter (0355) provides that the other major regulated utility providing service to Louisiana ratepayers is the Southwestern Power Electric Company (SWEPCO), which provides service to an area of north Louisiana. According to the commenter, one of SWEPCO's existing coal units serving Louisiana, and providing approximately 516 MW of capacity, would be significantly impacted by the EPA's proposal. The commenter states that SWEPCO's latest engineering estimate to install an SCR on that plant is $160 million. Furthermore, the commenter notes that SWEPCO is a 50 percent co-owner, resulting in a share of the cost estimated at $80 million. According to the commenter, SWEPCO's Louisiana customers have typically funded a 30 percent share of the costs for capital investments in SWEPCO generation facilities in the past. The commenter contends that using this same approach, Louisiana ratepayers would be responsible for approximately $24 million for the retrofit of one half of one unit.

Additionally, the commenter indicates that Cleco Power is another Louisiana public utility, but also has unregulated generation through an affiliate. The commenter notes that it has a small customer base and some of the highest retail rates in the state. The commenter states that the proposed rule would impact more than 5,000 MW of regulated and unregulated capacity owned by Cleco Power and its unregulated affiliate. Also, the commenter provides that Cleco Power believes that the EPA rule understates the level of capacity that would be affected by the proposed EPA rule as many of Cleco's units are old. As such, the commenter asserts that the proposed rule would impose similar cost risks on Cleco and its customers.

Commenter (0364) provides these comments because the citizens of Jonesboro will be financially impacted by the proposed FIP. The commenter holds financial interests in the output from electric generating units (EGUs) that will be affected by the proposed FIP. The commenter states the cost associated with implementation of the proposed FIP will vary among affected EGUs, but it is a cost increase that will in turn cause wholesale power costs to increase. Because the commenter's interest is municipally owned and operated on a not-for-profit basis, increased costs will not be borne by shareholders, but by the citizens of Jonesboro. The commenter notes that this is particularly troublesome due to the fact that median income ranks among the lowest in the nation.

Commenter (0375) states that the citizens of Arkansas are struggling with energy bills that have skyrocketed upwards during the last 18 months. The commenter provides that the proposed FIP leaves the state of Arkansas with a Hobson's choice of retiring generation units in an already supply-constrained market or spending hundreds of millions of dollars in compliance costs that will be passed on to ratepayers. The commenter notes that either way causes significant cost increases for consumers who are already struggling because of high energy costs.

Furthermore, the commenter provides that the state is also paying the cost for and examining the causes of the forced power outages that occurred in the state because of the extreme winter weather event of February 2021. The commenter contends that alarm bells are being rung by the experts that run the electric system because of reliability concerns driven in part by retirement of electric generating units being replaced with intermittent renewable energy sources. The commenter states that using unacceptable costs to force retirement of units needed to maintain reliability is a reckless strategy that we cannot afford.

Commenter (0407) is concerned that there would be a potential increase in cost of utility services for Mississippi ratepayers. The commenter states they needs more time to determine what that increased cost will be and may need additional information from the EPA on how it will implement the proposed FIP in order for the Commission to make a reasonably accurate cost determination. The commenter notes that the proposed FIP is broader in scope than previously developed transport rules, covers a much larger geographic area than prior rules, and that it would impose new control requirements on both Electric Generating Units (EGU) and a broad category of non-EGU industrial sources.

Commenter (0409) provides that rural electric cooperatives serve large expanses of the country that are primarily residential and typically sparsely populated. The commenter states that those characteristics make it comparatively more expensive for rural electric cooperatives to operate than other utility sectors, which traditionally serve more compact, industrialized, and densely populated areas. The commenter also asserts that this is why other types of utilities have typically shied away from serving rural areas, thus necessitating the advent of member-owned electric cooperatives. Using data from the United States Energy Information Administration (EIA) and other sources, the commenter estimates that rural electric cooperatives serve an average of 8 consumers per mile of transmission line and collect annual revenue of approximately $19,000 per mile of line, compared to the averages are 32 customers and $79,000 in annual revenue per mile of line in other utility sectors. The commenter contends that due to those geographically driven differences, 63 percent of rural electric cooperative members pay higher residential electric rates than do the customers of neighboring electric utilities. The commenter provides that higher rates impede the economic recovery of rural communities and can even challenge their viability, making it especially important for electric cooperatives to keep their electric rates affordable and avoid the sorts of unnecessary rate increases the proposed FIP portends. According to the commenter, low population density affects not only the cost of providing electricity, but also the demand for it. The commenter states that rural Americans are uniquely vulnerable to rising electricity costs. The commenter explains that in America's rural expanses, people generally do not live in closely confined houses or in apartments, but in detached, single-unit homes that endure significant exposure to the elements. The commenter estimates that more than 14 percent of cooperative consumers live in manufactured housing, which is often energy inefficient, while the national figure, by comparison, is six percent. According to the commenter, the percentage of mobile homes as a proportion of housing stock is 14.4 percent in cooperative territories. The national average is 6.1 percent. U.S. Census data with calculations provided by EASY Analytic Software, Inc. For those reasons, among others, the commenter states that the average household served by electric cooperatives uses 1,115 kWh of electricity each month, significantly higher than the 820-kWh monthly average for households served by investor-owned utilities (investor-owned utilities) or the 881-kWh monthly average for households served by municipal-owned utilities. Additionally, the commenter states that electric cooperatives are not-for-profit entities; they have no investor equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. The commenter also notes that electric cooperatives must ultimately pass along capital costs directly to their consumer-members through increased electric rates. The commenter provides that, given that electric cooperatives serve areas with low population density, these costs are borne across a base of fewer consumers and by families that already spend more of their limited incomes on electricity than do comparable municipal-owned utility or investor-owned utility customers. The commenter states that is yet another reason why cooperatives' members are disproportionately affected by the sorts of rate increases to which the Proposed Rule would give rise. Furthermore, the commenter notes that given that the G&T cooperatives maintain only marginal cash reserves for unforeseen events and anticipated operating expenses, financing for many capital projects necessarily require reliance on debt investors such as the United States Department of Agriculture's Rural Utilities Service (RUS), National Rural Utilities Cooperative Finance Corporation, and CoBank. As such, the commenter contends that the costs of borrowing, too, are necessarily passed on to cooperatives' consumer members. Ultimately, the commenter states that it is the cooperatives' consumer members who bear the cost of changes required by laws like the CAA and regulations promulgated under it.

Response:

The EPA does not agree that we are ignoring the impacts of the proposal on citizens and businesses across the country. This action will have substantial public health and environmental benefits that exceed compliance costs. The EPA prepared the *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard* (RIA). Chapter 4 of the RIA includes information on changes in fuel prices for fuels used to generate electricity and on changes in electricity prices.

EPA also notes that its EGU reductions are implemented through a trading program that provides additional compliance flexibility that cooperatives may utilize to accommodate any timing or cost concerns. Many of the nationwide figures provided above regarding cooperatives (including metric regarding the rural and transmission distances) are informed by locations in western states and midwestern states not covered in this final action. The EPA is using the same EGU applicability criteria that it has used in prior rules where successfully lamentation has included coverage of some large emitting cooperative units.

Comments:

Commenter (0412) contends that the proposed rule and particularly some of its add-on features such as dynamic budgeting will only add to the strain that customers are already feeling. The commenter states that certain judicial decisions may appear to limit EPA's ultimate deadline for instituting a rule, there remains considerable flexibility in EPA's design of key components and the timing of when those components are implemented. The commenter provides that as reserve margins shrink across the country and fuel costs rise, the EPA should use its discretion to balance its requirements under the rule with avoiding rate shock to customers.

Commenter (0420) is primarily concerned that the rule will destabilize the electrical grid and will drive energy prices up. The commenter contends that destabilization of the grid will be harmful to the Utah economy and to national security. The commenter states that higher energy prices will come at a time when Utah families are already struggling with escalating inflation with high prices at the gas pump, the grocery store, and more—further eroding their economic security.

Response:

See preamble Section VI.B.1.d for EPA's response to comment on reliability. The Regulatory Impact Analysis finds that rate impacts on average are well under 1 percent and that the benefits of the rule far exceed the cost.

7.3.4 Proposed Rule Will Diminish Ambient Air Quality

Comments:

Commenter (0300) states the EPA should evaluate the impacts of simultaneously ceasing or curtailing operations at numerous facilities that produce similar products on the ongoing supply chain issues sweeping the United States and strive to avoid further contribution to issues already devastating Americans and crippling the U.S. economy. Additionally, the commenter notes that the proposed FIP does not address the adverse impacts certain NO_X control technologies prescribed by the plan will have on ambient air quality. The commenter states that many of the emissions limitations proposed assume the application of post-combustion control technology, typically SCR or selective non-catalytic reduction (SNCR). According to the commenter, both technologies require increased energy demand resulting in indirect emissions increases at the facility or from off-site power sources (*i.e.,* via the grid). The commenter states that both technologies also require ammonia or urea, which inevitably results in some amount of ammonia slip. The commenter provides that ammonia readily reacts with sulfur oxides and nitrogen oxides in the stack or the atmosphere to form ammonium sulfates and ammonium nitrates, both considered $PM_{2.5}$. The commenter considers the recommendation from the Clean Air Scientific Advisory Committee to lower the primary $PM_{2.5}$ NAAQS and EPA's pending proposal regarding this matter, prescribing control technologies that are known to increase $PM_{2.5}$ emissions (direct and indirect) is not acceptable, especially when concerns exist regarding Mississippi's ability to meet the anticipated level of this new health-based standard. The commenter contends that the impacts of increased $PM_{2.5}$ at the source or in ambient air was not addressed or otherwise considered in this proposed rulemaking and should be further evaluated prior to issuing a final rule.

Response:

The rule is projected to reduce levels of $PM_{2.5}$ from EGU controls operating outside of the ozone season. In the Regulatory Impact Analysis accompanying the final rule, the EPA included estimates of the reduced incidence of $PM_{2.5}$ -attributable health effects associated with emissions reductions of NO_X, SO_2, and direct $PM_{2.5}$. To the extent there could be some localized increase in emissions of non-target pollutants, the EPA anticipates these would be quite small, and other regulatory programs under the CAA are available to address such concerns, such as permit-modification proceedings. We note that the potential for permit modification requirements being triggered is accounted for in the timing estimates for installation of pollution controls in the SC&A report on control installation timing for non-EGUs, included in the docket.

7.3.5 Proposed Rule Will Impede Federal Law

Comment:

Commenter (0435) contends that finalizing the proposal would also impede the successful implementation of the Infrastructure Investment and Jobs Act (P.L. 117-58). The commenter states that for the first time in the history of the CAA, the EPA is seeking to regulate emissions from certain industrial sources to address alleged ozone transport issues. The commenter provides that the affected types of industrial sources covered by the proposal include those in the natural gas, cement, iron, steel, and other sectors vital to the economy - but particularly important to the success of the IIJA. According to the commenter, by imposing new regulatory costs on domestic producers of key construction materials, the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards works at cross-purposes with the Buy America provisions included in IIJA to increase utilization of American-made products, including steel. The commenter states that the IIJA was a historic investment in our nation 's infrastructure, but inflation is already hitting the construction sector, quickly increasing prices and diminishing this substantial investment. The commenter asserts that imposing even more costs on construction materials will only further exacerbate price inflation and constrain production and use of American-made materials such as steel and concrete.

Response:

Thank you for your comments. This comment lacks reasonable specificity regarding any actual conflict with the provisions of P.L. 117-58.

7.4 Cost Analysis Revision Recommendations

Comments:

Commenter (0505) provides that the discount rates the EPA uses to adjust SCR equipment costs are not precise or consistent. The commenter contends that some of the sample combustion turbine SCR retrofit calculations adjust costs to 2021 dollars using a 2.5 percent average plant equipment cost increase from 2010 to 2020 while other costs are adjusted using three percent and seven percent discount rates to convert 2016 dollars to 2022 dollars and to project costs out to 2042 dollars. The commenter also notes that the January 2022 through March 2022 quarterly consumer price index, which is a surrogate for the more precise plant equipment price index, is 8.5 percent. Additionally, the commenter states that current expectations are that the plant equipment price index may stay above the EPA's proposed maximum seven percent inflationary level for the next several years. The commenter requests that the EPA reassess the discount rates it used.

Commenter (0765) contends that while EPA correctly relies on global social cost of greenhouse gases values to assess the Proposed Rule's benefits, it should modify its limited discussion of the rule's domestic climate impacts. The commenter provides that the EPA applies the flawed domestic-only values developed under the now revoked Executive Order 13,783 in a footnote, but those numbers are fatally incomplete, as EPA acknowledges in the footnote. The commenter states that the EPA should consider conducting a more complete sensitivity analysis using a sounder domestic-only estimate.

Furthermore, the commenter notes that the EPA explains that the social cost estimates developed under Executive Order 13,783 were incomplete underestimates that ignored how climate impacts occurring outside U.S. borders can directly and indirectly affect U.S. welfare. The commenter provides that the EPA presents what the Proposed Rule's climate benefit would be according to those values, highlighting climate benefits in the years 2023 and 2042. The commenter suggests that the EPA perhaps intended to show that even under such misleadingly low valuations, the proposed standards will still achieve hundreds of millions of dollars in annual climate benefits. The commenter also states that the domestic-only values calculated under the now-revoked Executive Order 13,783 were not simply incomplete and misleading underestimates; they have been ruled by a federal court to be illegally arbitrary values inconsistent with the best available science and economics. The commenter asserts that the EPA should make even clearer that these values are arbitrary and invalid and should not be relied upon.

At the same time, however, the commenter recommends EPA consider conducting a sensitivity analysis using a more realistic domestic-only valuation of the social cost of greenhouse gases. The commenter provides that the Working Group may in the future release guidance on an appropriate range for such a valuation, and considerable evidence suggests that—after weighing strategic benefits, spillover effects, and extraterritorial interests—any reasonable attempt to estimate the United States' share of climate benefits would be quite a high proportion of global benefits. The commenter contends that in the meantime, the best existing guidance available to EPA for a domestic-only estimate is not the arbitrary values calculated under the now-revoked Executive Order 13,783, rather EPA can look to the Working Group's past technical support documents for guidance.

Additionally, the commenter notes that in 2010, the Working Group provided an "approximate, provisional, and highly speculative" range of up to 23 percent of the global value as a domestic-only estimate but admitted even that was likely a significant underestimate. Though the commenter considers this to be an imprecise and gross underestimate, they believe those values at least have the virtue of some regulatory precedent, as government agencies have previously used them for sensitivity analyses. The commenter states that the EPA should therefore consider 23 percent of the global value to be the absolute minimum used for a domestic-only sensitivity analysis. The commenter also recommends EPA emphasize that such values are still gross underestimates, as they disregard most of the domestic impacts discussed above including international reciprocity, spillover impacts, and extraterritorial interests. The commenter provides that the EPA should also note that the integrated assessment models used to estimate the social cost of greenhouse gases were not designed for such localized, non-global estimates. The commenter states that the EPA could alternately look to the literature and consider conducting a sensitivity analysis with peer-reviewed domestic-only values such as those published by Yale University economics professor Matthew J. Kotchen, which for the United States are approximately 73 percent of the global social cost figures.

As such, the commenter contends that however EPA assesses domestic climate benefits—whether it sticks with its current approach or adopts an alternate approach—the Agency should clearly explain that the rule is cost-justified based on a consideration of only domestic climate benefits, and therefore the decision to focus on global climate benefits is in no way dispositive. The commenter concludes that, as the RIA shows, the rule is easily cost-justified without monetizing any climate benefits—domestic or global. Although, the commenter also notes that the EPA should maintain that the global perspective is the correct focus for its main analysis, for all the reasons detailed above.

Commenter (0765) contends that although Circular A-4 provides discount rates of three percent and seven percent as a default assumption, it also requires Agency analysts to do more than rigidly apply default assumptions. The commenter states that as such, analysis must be "based on the best reasonably obtainable scientific, technical, and economic information available," and agencies must "[u]se sound and defensible values or procedures to monetize benefits and costs, and ensure that key analytical assumptions are defensible." Rather than assume that a seven percent discount rate should be applied automatically to every analysis, the commenter states Circular A-4 requires agencies to justify the choice of discount rates for each analysis. The commenter provides that based on Circular A-4's criteria, there are numerous reasons why applying a seven percent discount rate to climate effects that occur over a 300-year time horizon would be unjustifiable—and that discount rates of three percent or lower are appropriate. First, the commenter notes that basing the discount rate on the consumption rate of interest (which the three percent rate represents) is the correct framework for analysis of climate effects, whereas a discount rate based on the private return to capital (which the seven percent rate represents) is inappropriate. The commenter provides that while Circular A4 suggests that seven percent should be a "default position" that reflects regulations that primarily displace capital investments, it also explains that "[w]hen regulation primarily and directly affects private consumption . . . a lower discount rate is appropriate." According to the commenter, the seven percent discount rate is based on a private sector rate of return on capital, as private market participants typically have short time horizons. By contrast, the commenter contends that climate change concerns the public well-being broadly rather than market participants narrowly. The commenter notes that rather than evaluating an optimal outcome from the narrow perspective of investors alone, economic theory requires analysts to make the optimal choices based on societal preferences and social discount rates. The commenter also notes that because climate change is expected to mostly affect large-scale consumption, as opposed to capital investment, a seven percent rate is inappropriate. Additionally, the commenter notes that the social cost of greenhouse gas estimates present climate damages in consumption-equivalent units, and therefore, Circular A-4's guidance in fact dictates application of consumption-based discount rates. The commenter provides that the National Academies of Sciences has agreed that a capital-based rate would be inappropriate for use with the social cost of greenhouse gases, given that climate damages are estimated in consumption-equivalent units. In addition, the commenter contends that there is strong consensus through the economic literature that a capital discount rate like seven percent is inappropriate for climate change.

Second, the commenter states that uncertainty over the long-time horizon of climate effects should drive analysts to select a lower discount rate. As an example of when a seven percent discount rate is appropriate, the commenter provides that Circular A-4 identifies an EPA rule with a 30-year timeframe of costs and benefits. The commenter explains that by contrast, greenhouse gas emissions generate effects stretching out across approximately 300 years. The commenter states that, as Circular A-4 notes, "[p]rivate market rates provide a reliable reference for determining how society values time within a generation, but for extremely long time periods no comparable private rates exist." As such, the commenter notes that Circular A-4 discusses how uncertainty over long time horizons drives the discount rate lower. The commenter provides that Circular A-4 cites the work of renowned economist Martin Weitzman and concludes that the "certainty-equivalent discount factor . . . corresponds to the minimum discount rate having any substantial positive probability." The commenter also notes that the National Academies of Sciences makes the same point about discount rates and uncertainty.

Third, the commenter asserts that a seven percent discount rate also ignores catastrophic risks and the welfare of future generations. The commenter states that, as the U.S. Environmental Protection Agency showed in a recent cost-benefit analysis, the seven percent rate truncates the long right-hand tail of social costs relative to the three percent rate's distribution. The commenter notes that the long right-hand tail represents the possibility of catastrophic damages. Thus, the commenter contends that the seven percent discount rate effectively assumes that present-day Americans are barely willing to pay anything at all to prevent medium- to long-term catastrophes. Given NEPA's mandate that agencies "recognize the worldwide and long-range character of environmental problems," the commenter states that it would not be reasonable for EPA to discount climate impacts at such a high rate as to effectively ignore the welfare of future generations.

Fourth, the commenter states that long-term time horizons in general counsel strongly against application of a capital-based rate. The commenter provides that The Working Group's latest guidance cites Li and Pizer's work on how the capital-based rate is generally inappropriate in many longer-term contexts. Specifically, Li and Pizer find that, given their best estimate of the shadow price of capital, the appropriate social discount rate collapses to the consumption-based rate relatively quickly, in the span of just several decades. The commenter asserts that given the long time horizon that analysis of climate policies demands, the capital-based rate is simply inapplicable.

Fifth, the commenter provides that several standard justifications for capital-based discount rates break down given the particular threats of climate change. For example, one argument for capital-based discount rates is that spending capital on climate abatement policies has opportunity costs and so, in policy analysis, future costs and benefits should be discounted at the rate of return to capital. However, the commenter adds that the irreversible, uncertain, and catastrophic risks of climate change may disrupt this "opportunity cost" rationale: while it may seem, for instance, that future, wealthier generations might have better opportunities to address climate change for themselves, irreversible or catastrophic damages could arise that make future mitigation efforts more expensive or impossible. Similarly, the commenter notes that if climate damages are "non-marginal," such that climate change significantly affects the very natural resources needed to drive economic growth, growth could plummet or even turn negative.

Sixth, the commenter provides that a seven percent discount rate is inappropriate because it is based on outdated data and diverges from the current economic consensus. The commenter states that Circular A-4 requires that assumptions— including discount rate choices—be "based on the best reasonably obtainable scientific, technical, and economic information available," yet Circular A-4's own default assumption of a seven percent discount rate was published 19 years ago and was based on data from even earlier. The commenter asserts that Circular A-4's guidance on discount rates needs an update.

Additionally, the commenter notes that Council of Economic Advisers (CEA) detailed recently after reviewing the best available economic data and theory. CEA gave two reasons to revise the seven percent rate, both of which are generally applicable but may have particular force in the context of climate change. The first argument is that the market data clearly shows that the long-term interest rates used to derive the consumption-based discount rates have fallen, such that the three percent consumption-based rate instead "should be at most 2 percent." Because of the relationship between long-term, tax-free interest rates and rates of return on capital (*i.e.*, the divergence between those rates is caused largely by taxation), a 1 percent drop in the consumption-based discount rate strongly suggests a corresponding drop in the capital-based rate. The commenter contends that this may be especially true for longer-term context like climate change, because of the lack of reliable market data to measure expected rates of return on assets held inter-generationally.

Furthermore, the commenter provides that the second argument the CEA presented for why the seven percent rate is too high is that market rates of return are artificially increased by returns associated with unpriced externalities, rents associated with market power, and private (as opposed to social) risk premiums. For example, a market return on an oil and gas investment is increased because the oil and gas operation can externalize some of the costs of its pollution onto society. Yet especially when crafting long-term climate policies, it would be inappropriate to discount future welfare based on the fact that the current generation of investors prefers the high market returns that are now available partly because of such externalities. As such, the commenter states that the seven percent capital-based rate is not only out of date and too high, but especially inappropriate for climate policy.

Finally, the commenter notes that Circular A-4 recognizes that intergenerational contexts raise unique ethical issues that further counsel for lower discount rates. Specifically, it recognizes that "[i]t may not be appropriate for society to demonstrate a similar preference when deciding between the wellbeing of current and future generations" as it does in the intragenerational setting." Circular A-4 thus recommends that agencies conduct additional analysis "using a lower [than three percent] but positive discount rate" for impacts with important intergenerational effects. The commenter asserts that most market data reflect at best individuals' current preferences for their own welfare over time and so simply does not capture society's preferences toward or ethical obligations to future generations. Basing a discount rate solely on market data ignores such important inter-generational considerations. The commenter notes that Executive Order 13,990 instructs agencies to ensure that the social cost of greenhouse gas values adequately account for "intergenerational equity." A seven percent rate ignores much of future generations' welfare and so would be inconsistent with that mandate.

However, the commenter concludes that while the above arguments are more than sufficient to justify rejecting a seven percent discount rate in the context of the social cost of greenhouse gases, the EPA should again note that the Proposed Rule would be cost-benefit justified even if the social cost of greenhouse gases were hypothetically zero—and, ipso facto, if it were calculated using a seven percent discount rate.

Commenter (0765) notes that the EPA has chosen to ensure that all climate benefits are discounted in an internally consistent way, by applying the same discount rate used to estimate the underlying social cost values (*i.e.*, 2.5 percent, three percent, or five percent) to calculate the present values of future climate benefits. That approach is consistent with the Working Group's guidance, but it also means EPA is calculating the present value of reduced greenhouse gas emissions differently than the present value of other costs and benefits (which mostly use three percent and seven percent discount rates).

If the opportunity presents itself, the commenter recommends EPA to consider working with OMB and the Working Group to move toward a declining discount rate framework that can straightforwardly resolve all these issues of consistent discounting, by adopting a single schedule of applicable discount rates that steadily declines over time. In the meantime, the EPA should expand on its rationale to its current approach to discounting. The commenter states the EPA should consider two non-exclusive approaches: (1) explaining why a general focus on discounting all costs and benefits at consumption-based rates, rather than at a seven percent capital-based rate, is appropriate in this particular rulemaking; and (2) explaining why special legal, economic, and policy considerations justify a different approach to discounting climate effects as distinct from other costs and benefits.

To begin, the commenter notes the EPA can explain that given the nature of the Proposed Rule's costs and benefits, it is more appropriate to discount all effects using consumption-based rates, and so the present value calculations that include some costs and benefits discounted at a seven percent rate can be viewed as lower-bound sensitivity analyses. The commenter provides that the capital-based discount rate theoretically assesses whether the net benefits from government action will exceed the returns that society could earn by instead investing the same resources in the private sector, but this framework for discounting and comparing benefits and costs makes sense only under the "extreme" assumption that all the costs of government action would "fully displace" (*i.e.*, crowd out) private investment. In this way, the capital-based rate "at best creat[es] a lower bound on the estimate of net benefits," by applying a maximum discount rate that reflects an extreme case not likely to apply to many government actions.

Additionally, the commenter states that in general, there is less of a chance now that U.S. government actions will crowd out private investments than there was in 1992 when OMB first set its seven percent capital-based discount rate, because the U.S. economy is relatively more open now. Additionally, the magnitude of the costs and benefits involved in many agency actions will be relatively small compared to the overall U.S. debt, again making it unlikely that agency actions will significantly crowd out private U.S. investment. The commenter states that some agency actions may also induce more private investment than they displace., and if the costs of agency actions will be more borne through displaced consumption rather than displaced investment, the crowding-out theory for a capital-based discount rate further breaks down. In this rulemaking, the commenter contends that the upfront technology costs will be felt primarily by individual consumers; other effects, like climate benefits, will be felt by society as a whole. In other words, because of the nature of the rule, the theory for a capital-based discount rate has a tenuous application at best. The commenter states that the EPA therefore would be justified in arguing for a focus on cost-benefit comparisons using consumption-based rates, with the application of a seven percent rate treated like a lower-bound sensitivity analysis.

Separately, the commenter asserts that the EPA would also be justified in taking a distinct approach to discounting climate effects, and should elaborate on the special legal, economic, and policy considerations justifying that approach. While effects like consumer operating cost savings will play out over the course of the next several decades, the climate effects of this rule are undeniably much longer term, affecting the welfare of future generations over centuries. Therefore, the commenter provides that the arguments in favor of lower consumption-based discount rates—based on long-term uncertainty, ethics, declining economic growth, inapplicable market data, and other considerations—apply much more strongly to climate effects than to other costs and benefits, and because a high capital based rate, like seven percent, will effectively ignore the welfare of future generations (*e.g.*, over the course of just 80 years, a seven percent rate discounts away 99.5 percent of a future effect's value), legal requirements to consider the welfare of future generations caution much more strongly against the application of a seven percent rate to long-term climate effects than to other costs and benefits. Notably, NEPA broadly instructs all agencies to interpret all their laws to the fullest extent possible to advance the national environmental policies, including to "fulfill the responsibilities of each generation as trustee of the environment for succeeding generations." Multiple Executive Orders, including Executive Orders 13,563 and 13,990, also call for agencies to weigh the interests of future generations appropriately and accurately.

Consequently, as the National Academies of Sciences have recognized, the commenter states that some differences in the application of discount rates may be warranted "when only some categories [of costs and benefits] have an intergenerational component." The commenter provides that the National Academies have offered recommendations for how agencies can best apply different annualized discount rates to climate impacts versus other costs and benefits, and EPA can rely on the National Academies' guidance to support its approach to discounting here.

Beyond the dozens of rulemakings (including prior EPA rules) in which agencies discounted climate impacts using consumption-based rates even when discounting other regulatory impacts using capital-based rates, the commenter notes that there is regulatory precedent outside the context of climate change for applying lower discount rates to long-term regulatory impacts. In 1999, the U.S. Department of Housing and Urban Development (HUD) finalized rules for lead-based paint hazards in certain residences. While OMB at that time recommended using only a seven percent discount rate, HUD discounted the lifetime earnings benefits for young children who avoid lead exposure at both three percent and seven percent. As HUD explained, a special "intergenerational discount rate" was applied to the lifetime earnings benefits only because "lifetime earnings benefits will be realized by the children and grandchildren of the adult taxpayers" bearing the rule's costs. The commenter notes that HUD also discussed why the seven percent discount rate may be less appropriate because the rule's costs, which would fall mostly on federally assisted housing, would be funded not by private investments but by federal expenditures, and so would tend to increase federal borrowing rather than displace private capital. Notably, HUD's analysis applied different annualized discount rates to different impacts depending on their nature and time horizon—demonstrating that the EPA is justified here in taking a similar approach.

Furthermore, the commenter provides that case law on the social cost of greenhouse gases also offers support for EPA's discounting approach. Specifically, in Zero Zone, the plaintiffs argued that the EPA had arbitrarily considered hundreds of years of climate benefits while limiting its assessment of employment impacts and other effects to just a thirty-year time horizon. The court upheld the regulatory analysis, concluding that the difference in time horizons was justified because the rule "would have long-term effects on the environment but . . . would not have long-term effects on employment." The commenter contends that the choice of time horizons is related to the choice of discount rate: any cost or benefit occurring beyond the end of the analytical time horizon is effectively discounted at a 100 percent rate (*i.e.*, it is assigned a value of zero). Analogizing from this precedent, the EPA's finding that the long-time horizon of climate change justifies a lower discount rate than the rate applied to shorter-term costs and benefits is similarly justified. The commenter contends that the EPA should explain the special economic, legal, and ethical considerations that support selecting a different annual discount rate for climate effects than for other costs and benefits.

Commenter (0765) the commenter provides that the EPA assesses climate benefits using discount rates for the social cost of greenhouse gases of 2.5 percent, three percent, and five percent. In its most recent Working Group TSD, however, the Group suggested that agencies "conduct[] additional sensitivity analysis using discount rates below 2.5 percent," just as EPA should include a sensitivity analysis with a robust domestic-only estimate, it should also prepare a sensitivity analysis based on a two percent or lower discount rate for the social cost of greenhouse gases.

As the Working Group explained in its February 2021 TSD, the commenter contends that there is considerable evidence from market data that the default estimate of the consumption-based discount rate should be revised down from three percent to two percent. In the context of long-term, intergenerational effects like climate damages, the case for a lower discount rate is even stronger, in light of ethical considerations and other factors. Multiple expert elicitations show a growing consensus around a discount rate below two percent, and factors like uncertainty, negative economic growth correlations, risk aversion, and the scarcity and non-substitutability of environmental goods all point strongly toward even lower discount rates.

For this reason, among others, the commenter asserts that the Working Group acknowledged in its latest TSD that its social cost valuations—presented at discount rates of 2.5 percent, three percent, and five percent—"likely underestimate societal damages from [greenhouse gas] emissions." The Working Group will evaluate the discount rate (among other issues) as it performs a full assessment of its social cost valuations to reflect the latest scientific and economic research. The commenter states that the Working Group has recommended that agencies apply additional sensitivity analysis around lower discount rates in the meantime.

To do so, the commenter recommends EPA look to the "value of carbon" estimates from the New York State DEC, which applied a two percent discount rate as its central value. Pursuant to DEC's estimates, at a discount rate of two percent social cost valuations for year 2020 emissions equal $125 per ton of carbon dioxide, $2,782 per ton of methane, and $44,727 per ton of nitrous oxide. DEC also recommended using a one percent discount rate for climate impacts, and provided annual social cost values for doing so. Because these valuations are based off of the Working Group's methodology, and differ only through the discount rate, the commenter asserts EPA can apply these valuations if it applies additional sensitivity analysis around lower discount rates.

Response:

Thank you for your comment. The commenter stated that the EPA adjusted some costs using three percent and seven percent discount rates to convert 2016 dollars to 2022 dollars and to project costs out to 2042 dollars. That is not accurate. The EPA presented costs throughout the RIA in 2016 dollars. The EPA estimates compliance costs for EGUs using IPM. The EPA used proxy compliance cost estimates from the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150. The proxy compliance costs for non-EGUs were calculated using a 7 percent interest rate. The relevance of inflation in conducting cost-effectiveness analysis at Step 3 is addressed in Section 4.3.1 of this document.

As part of fulfilling analytical guidance with respect to E.O. 12866, the EPA presents estimates of the present value (PV) of the benefits and costs over the twenty-year period 2023 to 2042. To calculate the present value of the benefits and costs of the proposed rule, annual benefits and costs are discounted using 3 percent and 7 discount rates as recommended by OMB's Circular A-4. These streams of benefits and costs are discounted using those discount rates back to the year 2022; they are not converted to 2022 dollars. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV.

With respect to climate benefits, before the proposal the U.S. District Court for the Western District of Louisiana issued an injunction concerning the monetization of the benefits of greenhouse gas emissions reductions by the EPA and other defendants. See Louisiana v. Biden, No. 21-cv-01074-JDC-KK (W.D. La. Feb. 11, 2022). Therefore, such values were not presented in the benefit-cost analysis of the proposal conducted pursuant to E.O. 12866.

The injunction was lifted while the proposal package was in interagency review. In response, the EPA prepared a supplemental memorandum titled "2015 FIP Climate Benefits Technical Memo,", which is available in the docket, EPA-HQ-OAR-2021-0668-DRAFT-0198. Following E.O. 13990, the EPA quantified the climate benefits in this technical memo using the February 2021 Interim SC-GHG estimates.

For the final action, the EPA continues to use the February 2021 Interim SC-GHG estimates, presenting benefits calculated using a five percent, three percent, 2.5 percent and three percent (95^{th} percentile value) discount rate. The presentation of monetized climate benefits is for informational purposes as a part of the overall benefit-cost analysis of the rule in the RIA and is not part of the record-based rationale for the rule, which implements requirements under CAA section 110(a)(2)(D)(i)(I) pertaining to the 2015 ozone NAAQS.

Comment:

Commenter (0538) states that the EPA should clarify and consider modifying several aspects of its cost-benefit analysis and should more fully explain whether and how this analysis informed its regulatory choices. In particular, the EPA should clarify its reasons for choosing the analytical timeframes it used in its cost-benefit analysis, give the greatest weight to the analysis that uses a 20-year timeframe, and evaluate whether a longer timeframe may result in a more accurate assessment of costs and benefits. In addition, the EPA should clarify the approach it took to discounting, and potentially give greater weight to calculations that use a three percent social discount rate rather than a seven percent social discount rate. The commenter then writes, the EPA should also either select the regulatory alternative that would yield the greatest benefits or provide a compelling reason not to do so. Based on the EPA's analysis, the more stringent alternative would generate $10 billion in additional benefits with a three percent discount rate over a 20-year period. The EPA should explain why it proposes to leave additional net benefits on the table.

Response:

The Agency presents analysis in the RIA over a 20-year time period because that allows for full implementation of the program and longer time periods may reflect additional uncertainties. The EPA presents the present value of the social net-benefits of the proposed rule at 3 percent and 7 discount rates as directed by OMB's Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year over the time period, would yield a sum equivalent to the PV.

The objective of the FIP is to assess and require emissions controls for EGUs and non-EGU emissions sources to eliminate significant contribution to downwind nonattainment or interference with maintenance at downwind receptors. The Agency finds as explained in Section V of the preamble that the selected emissions controls are sufficient to meet that requirement. The objective of the proposal is not to maximize net benefits.

8 Regulatory Text Changes

8.1 General

Comments:

Commenter (0501) requests that any significant change in course from the terms of the proposed rule be noticed through a supplemental proposal. The commenter noted that 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.

Commenter (0501) contends that the regulatory language the EPA has published includes provisions that are ambiguous, contain clerical errors, or otherwise should be clarified to avoid unnecessary confusion.

Response:

The EPA has made changes to the final rule regulatory text to address the specific issues raised by public commenters. These include changes to definitions, clarifications of applicability, and revisions of monitoring, recordkeeping, and reporting. The EPA is not expanding the scope of the final rule to additional states not included in the proposed rule and the EPA finds that none of these changes require a supplemental proposal.

9 Information Collection Burden

Comments:

Commenters (0376, 0416) oppose the EPA's approach (in the proposed rule) to developing emissions limits by avoiding industry-specific information collection. Commenter (0416) suggests that the alternative approach taken – relying on assumptions related to control device technical feasibility, baseline emissions rates, and control device efficiency is arbitrary and capricious, and results in deeply flawed limits. The commenter contends that the Agency typically conducts an Information Collection Request when developing new or modified CAA regulations for an industry in an effort to solicit existing data on source emissions, requests stack tests to address data gaps, and solicits information on technical and economic feasibility. The commenter adds that the Agency often engages with industry representative to ensure there is a clear understanding about the interpretation of the data. The commenter expresses concern that the EPA failed to follow this standard regulatory development approach when developing the proposed rule. According to the commenter, none of non-EGU industry categories were aware that the EPA was proposing stringent and expensive NO_X control requirements until EPA circulated the pre-publication version of the proposed rule. Commenter (0376) asks that the EPA engage industry and collect information prior to establishing emissions limits to properly promulgate effective regulations for industry.

Response:

Once the EPA has taken action to disapprove SIP submittals, the EPA must promulgate a FIP within two years. CAA section 110(c)(1). The EPA is subject to a consent decree deadline to finalize action on certain FIPs by March 15, 2023. 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. The timing of this action is discussed more in Section VI.A of the Preamble.

Commenters from several non-EGU industries and states raised general concerns regarding the ability for all sources to comply with the proposed emissions limits. As explained more in Section VI.C of the Preamble, 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. The EPA reviewed and considered industry specific information which the Agency received from public comments, and additional information provided by stakeholders during the comment period on the proposed rule.

The EPA provided a comment period until June 21, 2022, which provided 76 days to provide comment on the proposal, from the date it was published in the Federal Register on April 6, 2022. This public comment period included one extension of 15 days, from June 6 to June 21, 2022. Further, prior to publication of the proposal on April 6, 2022, the EPA published on its website on March 11, 2022, a pre-publication copy of the notice of proposed rulemaking as well as all of the major technical supporting documents, which allowed commenters to get a head start on their comments prior to the official publication of the proposal in the Federal

Register.[100]

[100] *See* https://www.epa.gov/newsreleases/epa-proposes-good-neighbor-plan-cut-smog-across-much-united-states.

10 Special Considerations

10.1 Complaints About Not Having Long Enough Comment Period

Comments:

General Comments

While many of the commenters (0198, 0200, 0201, 0205, 0208, 0209, 0210, 0211, 0213, 0222, 0224, 0231, 0232, 0235, 0238, 0239, 0241, 0245, 0244, 0258, 0278, 0279, 0286, 0295, 0300, 0301, 0308, 0317, 0323, 0336, 0338, 0340, 0341, 0344, 0348, 0357, 0359, 0363, 0364, 0365, 0376, 0372, 0387, 0398, 0396, 0405, 0407, 0411, 0431, 0437, 0504, 0505, 0509, 0516, 0518, 0528, 0526, 0529, 0541, 0550, 0760, 0764, 0782, 0798) appreciate the extension to the public comment period that extended the initial deadline by two weeks, many of the commenters still feel that the comment period offered no real relief and was not adequate/long-enough to allow sources/interested parties to properly analyze the modeling and supportive data used to prepare the rule, provide detailed comments and/or prepare supplemental information – making it difficult to confirm EPA' s modeling impacts and assumptions. The commenters, in general, asks that the EPA publish a re-proposed rule, make all the data and information relied upon publicly available and provide sufficient time for review and analysis – before closing the comment period. Several commenters remark on the length of the proposed rule (over 180 pages) and the voluminous of records and supportive data (over 200 documents) – *e.g.*, relevant case law and multiple technical support documents covering different aspects of the proposal ranging from inventories, modeling, control devices and measures, costs and policy analysis. At least two commenters (0359, 0505) maintain that the proposed rule lacks transparency. Some commenters (0295, 0301, 0411, 0526) argue that given a longer review period, it is probable that additional errors (to those already identified during the limited review period) would be found that could have a material impact on conclusions made by the EPA in this proposal. Similarly, commenter (0336) suggests a longer comment period would have allowed for discussions (between industry and EPA staff) to clarify and inform questions concerning the industrial unit standards; adding that the Agency may have also benefited from such question and answer (Q&A) sessions.

Commenters (0396, 0407) question the compressed comment period considering that it took the EPA more than two years to evaluate individual SIPs dealing with the same subject, and likely took more than a year to develop the proposal itself. Commenter (0300) implies that although EPA has identified the consent decree entered under Downwinders at Risk et al. v. Regan as the need to rush to regulate via this proposed FIP, the EPA is under no consent decree (*i.e.*, court ordered) obligation to finalize the FIP by any specific deadline. Similarly, commenter (0505) questions the length of the extension provided, given that so many stakeholders requested extensions.

Commenters (0509, 0782) pointed that the EPA modeling platform that has not undergone formal notice-and-comment review, and its use of a sophisticated photochemical grid model further complicates and limits one's ability to comment.

Commenters (0400, 0405, 0509, 0512, 0513, 0518, 0519, 0541, 0550, 0760), as a whole, object to EPA's choice to propose a FIP before the end of the public comment period for the proposed

SIP disapprovals and before some SIP disapprovals were proposed at all. Commenters (0400, 0512, 0513) add that this deprives the public, states, and affected entities the opportunity to submit meaningful public comment.

In a similar comment, commenter (0323) maintains that the EPA has not provided “legally sufficient” public notice and comment, and requests “adequate time for state response and public comment and review.”

Commenter (0523) believes that if EPA were to go further and finalize a rule that applies to SunCoke’s facilities, it likely would run afoul of the requirements for notice-and-comment rulemaking. In order for an agency to provide adequate notice and opportunity to comment, the final rule must be a “logical outgrowth” of the proposal. Small Refiner Lead Phase-Down Task Force v. EPA, 705 F.2d 506, 547 (D.C. Cir. 1983). The “notice must describe the range of alternatives being considered with reasonable specificity” such that interested parties will “know what to comment on” and the Agency’s decision making can be “better-informed.” “[V]ague and conflicting signals” are insufficient to provide reasonable notice. Michigan v. EPA, 213 F.3d 663, 692 (D.C. Cir. 2000). Here, the EPA has made, at most, some vague references that could indicate it intends to regulate non-recovery/heat-recovery coke plants, but those references are insufficient to alert interested parties that they should comment on the full range of questions involved in regulating such facilities.

Commenter (0504) implies that the proposed FIP disregards the CAA requirement that the EPA establish a rulemaking docket “[n]ot later than the date of proposal,” and if finalized, will violate EPA’s prohibition on finalizing rules “based (in part or whole) on any information or data which has not been placed in the docket.” The commenter expresses their concern that specific data/datasets, which the commenter suggests are fundamental to EPA’s analysis, are not currently available in the docket, even though the commenter states that they have submitted a request for this information to the Agency.

Lack of Access to Modeling Data

Commenters (0197, 0201, 0205, 0208, 0210, 0213, 0224, 0231, 0235, 0239, 0244, 0245, 0258, 0278, 0317, 0407, 0411, 0437, 0516, 0518, 0528, 0764, 0782) claim that the EPA has not provided adequate access to modeling data and informational and supporting documents, nor did the Agency grant a sufficient public comment period that allowed states and affected sources to properly analyze the proposal. Commenter (0782) states that this is particularly concerning because the failure to timely provide modeling files was also an issue in prior CSAPR rule updates. Commenter (0528) notes that the modeling platform use to support the proposed rule was made available mere months before the EPA released the proposed rule. Most commenters express their frustration that several informational and supporting documents to the rule – including inputs to the new modeling platform relied on by the EPA, were not readily available for review in the docket at the time of release (April 6, 2022), in violation of the APA. At least one commenter (0516) believes that there are sufficient grounds for reversal of the rule by the D.C. Circuit Court of Appeals, under the APA at 5 U.S.C. §706, because EPA failed to provide a meaningful opportunity to comment. Commenter (0518) recalls that federal courts have found that when an agency is hiding the information upon which it relies, upholding that practice would be "to condone a practice in which the agency treats what should be a genuine interchange as a mere bureaucratic sport." Conn. Light, 673 F.2d at 530-531.

Commenters (0208, 0210, 0244, 0437, 0509, 0518) share that stakeholders had to formally request data from the EPA directly – and then needed to physically ship a hard-drive to the government in order for EPA to upload and then return the hard-drive with the data. The commenters (including 0398) assert that even if requested, the EPA did not have a process in place to timely provide the data – *e.g.*, Ramboll U.S. requested the foundational modeling files three weeks before EPA published the proposed rule, but did not receive the data until the original public comment period was nearly half over. Similarly, commenter (0541) adds that the EPA released its “White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units” on April 21, 2022, with comments due originally on June 6. In another similar comment, comment (0437) states that they sent various questions to EPA after the proposal was published in the Federal Register in an attempt to understand the analysis that led to the proposed coverage of pulp and paper mill boilers and EPA posted additional information to the docket on April 27, 2022, three weeks after it opened. Commenter (0437) further asserts that some of the information in the docketed memos does not match information presented in the preamble, and the preamble discussion [do] not always comport with what ended up in the proposed regulatory language; thus, making commenting with such limited time more difficult. Another commenter (0317) claims that based on input from modeling experts, approximately five percent of the necessary data continues to be withheld by the EPA. Similarly, commenters (0208, 0244) formally request the following data and supporting documents, which according to the commenter are still not available:

1. The air quality contribution data that the EPA used to identify potentially impactful industries in 2023 and the R code that processed these data;
2. The CoST run results and the R code that generated the curves EPA used for identifying a cost threshold to evaluate emissions reductions in potentially impactful industries in 2023;
3. The maximum emissions reduction CoST run results that the EPA used to assess Non-EGU emissions reduction potential and estimated air quality impact in potentially impactful industries in 2023;
4. The 2023 state-receptor specific Revised CSAPR Update ppb/ton values, the Revised CSAPR Update calibration factors used in the AQAT for control analyses in 2023, the R code that processed the CoST run results using the maximum emissions reduction algorithm, and the summaries of the air quality improvements;
5. The 2023 state-receptor specific Revised CSAPR Update ppb/ton values, the Revised CSAPR Update calibration factors used in the AQAT for ozone for control analyses in 2023, and the R code that processed the CoST run results that the EPA used for its impactful boiler assessment;
6. 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 the Non-EGU

Screening Assessment tables on estimated emissions reductions, maximum PPB improvement, and costs.

Commenters (0504, 0514, 0798) maintain that the proposed FIP violates the procedural protections in CAA section 307(d), because the EPA fails to provide stakeholders with key information/documents until well after publications of the proposed FIP. As an example, commenter (0504) notes that the EPA did not provide the 2023 Industry Identification Analysis until April 27 – three weeks after the proposed FIP was published in the *Federal Register*. The commenter believes that this analysis is critical to understanding this rulemaking, because it identifies the inventory of the facilities the EPA considered in its modeling and screening analysis, the controls EPA believed could be utilized at each facility, the cost of those controls, and the NO_X emissions reduction potential EPA believes can be achieved through use of such controls. The commenter provides a list of 6 critical information/data that, according to the commenter, the EPA failed to readily provide, or is only available upon request – model inputs, codes and Control Strategy Tool ("CoST") run data (*e.g.,* CoST run results and the R code that generated the curves EPA used for identifying a cost threshold to evaluate emissions reductions in potentially impactful industries in 2023). Commenter (0514) suggests that under CAA section 307(d), it would be unlawful and arbitrary to include any emissions limits for SAFs or any regulation of silicon production absent a new proposed rule providing the opportunity for public comment on the basis for any such newly proposed limits. The commenter (including comment 0798) briefly recaps rulemaking procedures under CAA section 307(d) – *e.g.,* a proposed rulemaking must "include a summary of — (A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule." Commenter (0514) contends that the proposed rule does not seek to regulate NO_X emissions from SAFs or silicon metal producers and its accompanying docket includes no basis for any emissions limit specific to SAFs, no basis for determining that post combustion controls would be feasible or cost effective, and no basis for subjecting SAFs or silicon metal producers to regulation under the good neighbor provision in the first place.

Timeline for Processing Data

Commenters (0231, 0258, 0509, 0516, 0518) highlight that it takes several days to copy and setup the large files, like the modeling files that included over 37 Tb of data, so that a stakeholder could use the data and conduct a proper review. Commenter (0231) states that 10 Terabytes is equivalent to the entire printed collection of the U.S. Library of Congress. The commenters further notes that to conduct a standard analysis of the source apportionment modeling, stakeholders would require a minimum of an additional 80 - 100 days of computer time on a high-performance computer to assess the results. Commenter (0764) estimates 225 days (to reproduce modeling data) based on the capabilities of two state-of-the-art CAMx modeling clusters. The commenter provided the following schedule:

- 50 days for benchmarking the nine scenarios

- 5 days for pre-processing 1st and 2nd of nine scenarios
- 20 days for CAMx processing of 1st and 2nd of nine scenarios (assuming 10 tags)
- 10 days for post- processing 1st and 2nd of nine scenarios
- 35 days for pre-processing, processing, and post-processing of 3rd and 4th of nine scenarios
- 35 days for pre-processing, processing, and post-processing of 5th and 6th of nine scenarios
- 35 days for pre-processing, processing, and post-processing of 7th and 8th of nine scenarios
- 35 days for pre-processing, processing, and post-processing of 9th of nine scenarios.

Commenter (0317) provides the following timeline (of 76 days) for performing the most basic of analysis:

- Obtain EPA CAMx files for the above 9 scenarios: **two months**. Including SMOKE scripts/inputs/outputs; meteorological data; CAMx scripts/inputs/outputs; Post-processing scripts/inputs/outputs;
- Transfer EPA CAMx files to BREEZE CAMx clusters: **two weeks**. Including modeling environment setup and testing, matching EPA's SMOKE/CAMx versions and recompile them if necessary;
- Benchmarking the above 9 scenarios: **two months**. Rerunning EPA's 9 scenarios as they are (without any modifications), can compare BREEZE clusters rerun results with EPA's results;
- Inventory changes/updates: **three weeks** (EC two weeks; BREEZE One Week). Updating source parameters/emissions rates/any other parameters which do not match the actual facilities, removing none-existing/inactive/shutdown sources;
- Pre-processing (mainly SMOKE) updated baseline scenarios 1st (2016fj) and 2nd (2023fj) of 9 scenarios: **one week**;
- CAMx processing updated baseline scenarios 1st (2016fj) and 2nd (2023fj) of 9 scenarios (assuming 10 tags): **three weeks**;
- Post-processing updated baseline scenarios 1st (2016fj) and 2nd (2023fj) of 9 scenarios: **two weeks**;
- Pre-processing (mainly SMOKE), CAMx processing (assuming 10 tags), post-processing updated baseline scenarios 4th (2026fj) and 9th (2032fj) of 9 scenarios: **six weeks**;
- Pre-processing, processing (assuming 10 tags), and post-processing for updated 3th (2023fj_ussa) and 5th (2026fj_ussa) scenarios: **one month**;

- Pre-processing, processing (assuming 10 tags), and post-processing for updated 6th (2026fj_egusa) and 5th (2026fh_nonegusa) scenarios: **one month**; and
- Pre-processing, processing (assuming 10 tags), and post-processing for updated 8th (2026fj_30NO_X) scenario: **one month**.

Insufficient Comment Period

Commenters (0197, 0198, 0208, 0210, 0222, 0232, 0323, 0348, 0504) suggest that even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the proposed FIP, the public comment period EPA provided remains woefully insufficient due to the proposed FIP geographic scale, the scope of covered industry sectors, the number of potentially impacted emissions units, and the remarkable extent to which the Agency assumes emissions from those units can be abated using what EPA believes to be widely available and cost-effective controls. The commenters assert that it is not reasonable for EPA to expect stakeholders to consider this voluminous and widely dispersed record in responding to the Agency's request for comments.

Commenters (0198, 0210, 0222, 0231, 0241, 0244, 0407, 0516) underscore that the EPA is seeking comment on more than 50 specific issues – *e.g.*, the feasibility of phasing out, retiring, and replacing wet process kilns. These questions are significant technical inquiries that require comprehensive data gathering and complex analysis.

Commenters (0213, 0376, 0398) maintain that the provided comment period does not take into account real-world staffing resources or the complexity and expanse of the information to be analyzed by state implementers, as well as, according to one commenter, failing to consider the ripple effects of a sloppy and catastrophically costly FIP being forced on industry sources in states, like Arkansas that are less than marginal contributors to downwind ozone issues.

Commenters (0197, 0198, 0222, 0224, 0232, 0279, 0323, 0317, 0340, 0359, 0363, 0364, 0500, 0541) imply that the EPA was attempting to overwhelm affected parties by proposing a short comment period for such a complex rule and associated technical support documents, coupled with overlapping comment periods for both SIP disapprovals and the CT White Paper. The commenters believe that states should have reasonable time to digest EPA data and revise the SIP, and at least one commenter claims that this approach to overcome states is an unacceptable abuse of power. Commenters (0198, 0323) claim that the EPA's coincident rulemaking proposals for the FIP and SIPs effectively deprived stakeholders of about 30 percent of the proposed transport rule comment period; adding it is disingenuous for the EPA to act in a rush manner only in an effort to comply with legal requirements. Commenter (0317) maintains that typically, states would have up to twenty-four months to work with EPA to address alleged potential deficiencies identified by the EPA in a finalized SIP disapproval before EPA is bound to implement a federal plan [42 U.S.C. § 7410(c)(1)].

Commenters (0405, 0509, 0516, 0764) assert that numerous errors regarding the data the EPA utilized (*e.g.*, for the cement industry's existing NO_X emissions controls) were found during an initial review of the proposed rule, and plan to continue reviewing the modeling data after the comment period closes and may submit additional comments outlining errors and erroneous conclusions at a later date. Commenter (0516) adds that significant time is needed to evaluate and assess the impact of the source cap limit on cement plants that was lifted for the DFW Nonattainment Area; noting no justification for imposing the source cap limit on the cement industry was provided. The commenter asserts that the EPA copied the source cap limit specific to the DFW Nonattainment area, thinking that it could be applied more broadly to the cement industry, without evaluating, for example, the implications of the limit on the cement kilns in the 23 affected states, whether they could feasibly comply with such limits, etc. Commenter (0405) requests that the EPA remove the Iron and Steel sector entirely from the proposed FIP and allow for ample time in the future to accommodate a case-by-case RACT analysis.

Commenter (0323) briefly describes some examples of missed opportunities to submit additional technical analyses, including Alpine Geophysics which would have, for instance, executed an air quality modeling simulation of the control case to corroborate EPA's findings with the simplified AQAT analysis.

Commenter (0239) alludes that they would like additional time to evaluate the cost threshold for nitrogen oxide ("NO_X") reductions and evaluate the AQAT tool used to support the rule.

Commenter (0344) express their concerns that some sources (*e.g.*, municipal waste combustion) not included in the proposed rule will not have had an opportunity to comment on emissions limits that will potentially be included in the final rule and urge the Agency to include another comment period to properly inform states and affected sources how the EPA’s intends to address these concerns.

Commenter (0397) respectfully requests that the EPA re-publish the FIP for public comment if any state’s budget changes by 10 percent or more between the proposed FIP and the “final” rule. Meaningful feedback on a rule proposal requires that states have a reasonable expectation that the final rule will not be a significant departure from the proposal. Further, the EPA should re-propose the FIP if, based on comments submitted for this rulemaking or changes due to feedback provided prior to publication of the proposed FIP, any changes made to the 2016 v2 EMP result in a change in the status of the linkages between any upwind state and any downwind nonattainment or maintenance receptor such that the state would be removed from the list of participating states or a new state is added.

Response:

The EPA disagrees that it provided insufficient time for public comment; we have provided sufficient time for the public to review and comment on the policy, legal, and technical bases for this action. The EPA has otherwise fully complied with the procedural and docketing requirements of CAA section 307(d). Despite their complaints that the EPA failed to provide sufficient public process, the commenters here actually participated in this public notice and comment process, in many cases submitting detailed and lengthy comments.

Congress’ presumptive minimum period for public comment on CAA regulations is 30 days. CAA section 307(h). In order to provide time for a public hearing and allow for the submittal of rebuttal information for 30 days following that hearing, the EPA typically provides at least 45 days for comment on regulations subject to the rulemaking requirements of CAA section 307(d). *See id.* 307(d)(5)(iv). Here, the EPA provided a comment period until June 21, 2022, which provided 76 days to provide comment on the proposal, from the date it was published in the Federal Register on April 6, 2022. (The EPA held a public hearing on April 21, 2022. The EPA granted one extension of the comment period of 15 days, from June 6 to June 21, 2022. 87 FR 29108 (May 12, 2022).) Further, prior to publication of the proposal on April 6, 2022, the EPA published on its website on March 11, 2022, a pre-publication copy of the notice of proposed rulemaking as well as all of the major technical supporting documents, which allowed commenters to get a head start on their comments prior to the official publication of the proposal in the Federal Register.[101]

With respect to the comment that states and affected sources would not have an opportunity to comment on emissions limits for municipal waste combustors, the EPA disagrees. At proposal, the EPA made a detailed request for comments on whether NO_X emissions reductions should be sought from MWCs to address interstate ozone transport. The EPA specifically asked for comments on potential emissions limits, control technologies, and control costs. In regard to emissions limits, the EPA requested comment on emissions limits of 105 ppmvd on a 30-day average and a 110 ppmvd on a 24-hr average based on determinations made in the June 2021 OTC *Municipal Waste Combustor Workgroup Report* (OTC MWC Report). *See* 87 FR 20085-20086.

With respect to commenters' complaints that they were not afforded sufficient time to comment on the air quality modeling, the EPA disagrees. The 2016-based meteorology and boundary conditions used in the modeling had been available to the public for nearly a year and a half before proposal through the 2016v1 platform, which was used for the Revised CSAPR Update (proposed in October of 2020, 85 FR 68964). In addition, the updated emissions inventory files used in the proposal modeling (2016v2) were publicly released September 21, 2021, for stakeholder feedback, and have been available on our website since that time.[102] The CAMx modeling software that the EPA used has likewise been publicly available for some time: CAMx version 7.10 was released by the model developer, Ramboll, in December 2020. And on January 19, 2022, we released on our website and notified a wide range of stakeholders of the availability of the modeling results for 2023 and 2026 (including contribution data) along with many key underlying input files.[103]

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[104] we gave states and other interested parties multiple opportunities prior to our early 2022 SIP and FIP proposals to review and develop comments on the 2015v2

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[101] *See* https://www.epa.gov/newsreleases/epa-proposes-good-neighbor-plan-cut-smog-across-much-united-states.

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

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

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

modeling.

Due to the Covid-19 pandemic, the docket office was not open to the public during the comment period. Instead, the EPA posted a memorandum in the docket, Document ID No. EPA-HQ-OAR-2021-0668-0068, that described 1) information available in the Air Quality Modeling Proposed Rule TSD and 2) how the public could obtain the full set of air quality modeling input and output files. This memorandum provided a complete list of files available from the EPA upon request.

We supplied the full set of modeling files (roughly 15 terabytes) to those who requested them; while the EPA acknowledges the process of delivering such large files can take time, we do not believe having all of those files is necessary for the public to be able to comment meaningfully on the proposal here. For those who requested those files at the time of proposal, the EPA was able to ship the files in time to allow such requesters over 30 days to review them before the close of the comment period on the FIP. Further, for those who wished to comment on the EPA's modeling through reviewing all of those files and/or through running their own modeling, we note that the EPA used the same 2016v2 modeling of 2023 for all of its proposed SIP actions and the proposed FIP. Commenters could comment (and many did comment) through any of those public comment periods on the modeling, and the EPA considered such comments in taking final action on the SIP submissions and in taking this final action. Given the overlapping timing of most of EPA's proposals, there was at least one public comment period open at all times on the proposals using that modeling from Feb. 22, 2022, when the first set of disapprovals were issued, through July 25, 2022 (the close of the public comment period on the proposed disapprovals of several western states). That is effectively a combined comment period of 153 days, and is more than sufficient, in EPA's view, to allow for meaningful comment even with respect to technically complex modeling information.[105]

EPA does not agree that we are obligated to issue a new proposal with respect to the changes in this final rule that have been made from the proposal. The EPA has conducted new modeling (2016v3) in response to issues with the 2016v2 modeling raised by commenters; this is a logical outgrowth of the proposal. It is axiomatic that an agency may rely on new information not available at the time of proposal to support its final rule. *See, e.g., Chamber of Commerce v. SEC*, 443 F. 3d 890, 900 (D.C. Cir. 2006) ("[F]urther notice and comment are not required when additional fact gathering merely supplements information in the rulemaking record by checking or confirming prior assessments without changing methodology.") (citing *Solite v. EPA*, 952 F.2d 473, 485 (D.C. Cir. 1991)); *Fertilizer Inst. v. EPA*, 935 F.2d 1303, 1311 (D.C. Cir. 1991). The EPA issued the proposed rule outlining all data, assumptions and

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[105] The EPA proposed action on a re-submitted, new SIP submission from Alabama later in 2022, again using the same 2016v2 modeling, and so an additional comment period was open with respect to the application of the 2016v2 modeling in assessing good neighbor obligations for the 2015 ozone NAAQS from the date of that proposal, October 25, 2022, through November 25, 2022. *See* 87 FR 64412. The EPA gave consideration and responded to comments regarding the modeling on that proposal in the final action disapproving Alabama's and 20 other states' SIP submissions. *See* 86 FR 9336 (Feb. 13, 2023).

methodologies supporting the proposed regulatory requirements, all of which was available for comment. We received many comments on that data and our analytical methodologies, and we incorporated this feedback into the modeling conducted for the final rule. This updated information was found to support a final rule that is quite similar to what was proposed, and to the extent it differs, it is clearly a logical outgrowth of the proposed rule.

Where the EPA has found that states are linked in 2023 for which we had not proposed a FIP, or where the basis for any linkage may differ from the basis at proposal (or the EPA may ultimately determine no linkage exists), we are deferring action on those states to a separate rulemaking proceeding to afford an opportunity for review and comment on those issues. This is the case for Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming. Where states have been found to be unlinked in the final analysis, we are not promulgating a FIP (this is the case for Delaware). Where states have been found in the final analysis to not be linked in 2026, the EPA has adjusted the control stringency of the FIP to reflect this. Further, the adjustments in emissions control requirements for EGUs and industrial sources all are reflective of comments the EPA received on the proposal, and in general, these changes have reduced the stringency of the regulatory requirements in response to claims of infeasibility or the need for greater flexibility. For example, contrary to commenters' concerns here, the EPA is not regulating non-recovery/heat-recovery coke plants or submerged arc furnaces in this action and has removed the source cap limit for cement plants.[106]

The EPA also continued to meet with any outside stakeholder groups who requested meetings beyond the close of the comment period. These meetings are memorialized by memoranda to the docket, and the EPA has included any written material it received during or associated with these meetings to the docket as well. In general, these meetings afforded stakeholder groups an opportunity to further elaborate on their comments to ensure the Agency fully understood commenters' concerns.

Any additional opportunity for comment on the updated data used for this final action is therefore unnecessary, and would only delay implementation of the emissions reductions achieved by this rulemaking and required under the Act to be implemented by 2023 if possible. *See* Section III.B and VI.A of the preamble and Section 3.1While EPA is subject to a consent decree deadline to finalize action on certain FIPs by March 15, 2023, the amount of time EPA could provide for public comment was also informed by our substantive obligation to see that good neighbor obligations for the 2015 ozone NAAQS are addressed as expeditiously as practicable and no later than the next attainment date. *See Wisconsin*, 938 F.3d at 313-20; *see also New Jersey v. Wheeler*, 475 F.Supp.3d 308, 331 (S.D.N.Y. 2020) ("Congress necessarily determined that reasonable expedition was required [in implementing good neighbor obligations] rather than the formulation of perfect FIPs."). Under these circumstances, and

[106] Regarding commenter's complaint that a particular file was not added to the docket until April 27, 2022, EPA does not necessarily concede that having this file was necessary to meaningfully comment on the proposal, but in any case, this still afforded ample time for commenter to review and comment on that document by the close of the comment period on the FIP, and commenter (0437) in fact did so.

mindful of the legal and procedural obligations EPA is under, as established by Congress and the courts, the EPA believes the comment period length was appropriate and consistent with the requirements of the CAA.

Lastly, the EPA disagrees that we failed to readily provide six critical sets of information/data. The Agency received a few requests for the data cited above and after each request quickly shared the files through online forms, such as Microsoft OneDrive. The Agency also asked that those requesting the information confirm its receipt. We did not receive any responses that the information was not accessible.

10.2 States Not Linked in 2026

Comments:

Commenter (0533) supports EPA's proposal not to require additional reductions past the 2023 stringency level for Alabama, Delaware, and Tennessee to avoid overcontrol; however, the commenter is concerned that the EPA proposes to potentially overcontrol emissions from other states, including Arkansas, Mississippi, and Wyoming. The commenter believes that requiring NO_X reductions that would lead to overcontrol in such states would be arbitrary and capricious and contrary to the CAA. Accordingly, the commenter asks that the EPA reevaluate the NO_X emissions reductions needed from such states for the 2026 ozone season—including conducting new modeling before the 2026 budgets are established—to ensure that there will be no overcontrol. The commenter further requests that the EPA also ensure that EGUs are not bearing a disproportionate burden of any controls needed for the 2026 ozone season.

Commenter (0558) asserts Delaware has existing measures in place designed to reduce ozone from its sources and its approved SIP contains sufficient provisions to comply with Section 126's transport obligations. The commenter concludes that as a result of measures currently underway at the state to reduce ozone and comply with transport obligations that the participation of Delaware sources in the trading program will have almost no effect on ozone concentrations. The commenter notes that the EPA's new modeling indicates that Delaware is linked to the Bristol monitor in 2023; however, the commenter underscores that the monitor is projected to attain by 2026. The commenter adds that the EPA's model results show that Delaware's participation in the trading program would only reduce its contribution to the Bristol monitor by 0.04 ppb, a value equal to 0.05 percent of the NAAQS, between 2023 and 2026. The commenter briefly discusses different actions, programs, and regulatory steps that have been implemented by the state of Delaware aimed at reducing NO_X emissions (*e.g.,* Minor New Source Review Provision [7 DE Admin Code 1125 section 4] and a facility-wide cap for the Delaware City Refining Company) and maintains that the state could have demonstrated that it had already done the work to reduce ozone in their state.

Response:

For the final rule, the EPA updated the CAMx photochemical air quality modeling of the 2023 and 2026 base cases. The results of this modeling are presented in the preamble in Section IV.F. The maximum air quality contribution for Delaware and Tennessee are below the Step 2 threshold. However, as shown in preamble Table IV.F-3 Tennessee's maximum contribution to a "Violating Monitor" is 0.85 ppb. As described in preamble Section IV.F, Alabama has a contribution in 2023 that is above the Step 2 the threshold. Preamble Section I describes how EPA is addressing each of the three states Alabama, Delaware, and Tennessee for this final rule. With regards to Arkansas, Mississippi, and Wyoming, the EPA describes its response to Wyoming in the preamble Section I. With respect to Arkansas and Mississippi, the response can also be found in preamble Section I and the overcontrol assessment for these states in preamble Section V.D (as well as Section C.3 of the Ozone Transport Policy Assessment TSD). As described in Section I of the preamble, Delaware is not being included in this final rule, so the comment regarding Delaware is moot.

10.3 Comments About AQAT

Comments:

General Comments

Commenters (0289, 0300, 0306, 0323, 0336, 0340, 0343, 0365, 0395, 0397, 0409, 0437, 0499, 0505, 0509, 0518, 0528, 0554, 0760, 0764) oppose EPA's use of a simplified Air Quality Assessment Tool (AQAT) for determining EPA's projections of reductions, rather than on CAMx modeling, the preferred method for assessing the potential impact of proposed controls. The commenters maintain that the EPA's use of the AQAT is inappropriate, erroneous and misleading – leads to unsupported conclusion. A few commenters state that the EPA's rationale – that they did not have the time or the resources to use photochemical air quality modeling, because it was under a court deadline, is un-compelling, especially considering the exorbitant cost and resources it will require of states to implement EPA's selected controls. At least one commenter (0340) acknowledges that the EPA has used this assessment tool in the prior CSAPR rules; however, the commenter notes that those prior rules did not include such a significant reduction in NO_X emissions from non-EGU sources or contain required controls that could lead to early retirement of needed EGUs. Most of the commenters underscore the point that the AQAT is a spreadsheet, not a photochemical grid model. The commenters agree that to calculate ozone measures like those proposed, a photochemical grid model is needed; some of which add that the use of a simplified AQAT goes contrary to EPA's air-quality modeling guidelines. Several commenters express their concerns that the EPA seeks to use AQAT to a degree of precision it is not designed for or capable of achieving; noting EPA themselves have conceded the point that "[a]ir quality modeling would be the optimal way to estimate the air quality impacts at each cost threshold level from EGUs and non-EGUs emissions reductions" and that "AQAT is not the equivalent of photochemical air quality modeling." The commenters emphasize that these positions support the standpoint that results from this NPR are inadequate for the magnitude of this rule; adding that the hastily developed AQAT review is plagued by a number of errors. Some commenters request that the EPA re-run its model and make the results of the recommended air modeling publicly available and provide sufficient time for review and comment, as directed under the APA. At least one commenter (0340) recommends that the EPA withdraw the rule completely and consider other methods for determining upwind states' contributions to downwind issues, timing for EGU controls and emissions reductions, and potentially impacted non-EGU industries.

According to the commenter (0323), for reasons related to timing and resource constraints, the EPA elected not to perform full-scale photochemical air quality modeling in support of quantifying the impact of air quality improvements associated with various control cases considered for adoption in the proposed FIP and used its simplified Air Quality Assessment Tool (AQAT) instead. The commenter claims that considering the importance of this regulation, significant cost to impacted industries and electric consumers, potential impact on electric supply reliability, and miniscule air quality benefit projected for the required control scenario, at a minimum, the EPA should have run an air quality simulation to corroborate its findings with the simplified AQAT. According to the commenter, anything less constitutes an arbitrary and capricious action.

AQAT - Trading Enhancements

Commenter (0554) suggests that the assumptions underlying the EPA's AQAT analysis may not be valid due to the trading enhancements (*e.g.*, backstop daily limits, dynamic budgeting, etc.) that the EPA has proposed. Commenter briefly discusses the approach taken by the EPA in developing the AQAT – *e.g.*, the EPA determined the emissions reductions that would be generated by the controls required under its proposal, and then determined whether those emissions reductions will result in over-control. While this approach seems logical on its face, the commenter highlights that the EPA does not appear to have recognized that the emissions reductions it assumed based solely on implementation of controls may be far less than will actually be forced due to the restrictions on trading EPA has proposed.

AQAT – Overcontrol

Commenters (0306, 0505) claims that the EPA's reliance on the AQAT alone is not sufficient to determine if emissions are overcontrolled due to the proposed FIP; noting that the EPA itself concedes that the AQAT is not the optimal approach, nor is it equivalent of photochemical air quality modeling. The commenters recommend that the EPA perform one accurate and sufficient photochemical modeling run with the final set of selected control strategies to verify that the reduction in state contributions and design value are similar to those estimated by the AQAT tool.

Commenter (0289) understands that using the AQAT tool helps to conserve resources as source apportionment photochemical modeling is both time- and resource-intensive; however, the commenter contends that once EPA decided on its proposed controls at Step 3 it should have remodeled using its proposed control strategy scenarios for 2023 and 2026 using the source apportionment modeling. The commenter adds the AQAT tool does not consider the timing of ozone episodes at downwind receptors and how they relate to upwind state emissions reductions from specific sources they are proposing to control. While the commenter understands why the EPA would choose not to re-run the source apportionment modeling for every control strategy it evaluates, at the very least, the Agency should be obligated to re-run the model for the proposed control strategy. Without doing so, it leaves highly open the question of whether the proposed control strategy will result in over-control on any upwind states.

Commenters (0323, 0499, 0764) state that the RIA at proposal shows that the application of the simplified AQAT leads to maximum estimated air quality improvements at downwind receptors by no more than two tenths (0.2) of a part per billion ("ppb") ozone. The commenters add that as estimated by the AQAT method, no upwind state linkage was broken from receptors in downwind states. Based on these results, the commenters believe that the EPA should have prepared a final air quality simulation to determine whether actual modeled improvements would occur consistent with the base case modeling results and with EPA's own guidance.

AQAT – Third Party Reviewers and Reports

Commenters (0323, 0409, 0499, 0760) reference a review (entitled Review of EPA's Use of AQAT in the Federal Implementation Plan for the 2015 Ozone NAAQS Transport Proposed Rule, dated June 16, 2022) of EPA's use of the AQAT (for its Step 3 analysis) performed by a third-party reviewer (Alpine Geophysics). This review identified and discussed more than 10 errors in the report. Commenters (0323, 0499) briefly describe the contents of a memo (attached as supporting documentation) prepared by Alpine which reviews the inputs and assumptions made by the EPA in using the simplified AQAT and documents how this "shortcut" by the EPA compromises its technical findings as well as the impact of recommended controls in the proposed FIP – identifies methodological errors in EPA's approach. Commenter (0760) urges the EPA to review the Alpine report prior to making any final determinations concerning Step 3 of the interstate transport analysis.

Commenter (0518) references the Ramboll Report, which explains why EPA's claim "a significant portion of the nonlinearity is accounted for by using the calibration factors and having the air quality estimates occur at levels of emissions between the 2026 base case and the other case used in the calibration (which were both modeled in CAMx)" is invalid.

Commenter (0395) states that the AQAT itself has numerous shortcomings which are identified further in the Sonoma Report including the assumption of a linear relationship between emissions and resulting ozone concentrations and its treatment of all sources in Texas the same, despite important differences such as location, size, temperature and height.

Modeling Guidelines

Commenters (0365, 0499, 0509, 0518, 0764) argue that the EPA's decision to use a "simplified" AQAT tool is contrary to the Agency's modeling guidelines, which specifically recommend that the evaluation of ozone impacts due to a single source or groups of sources should be based on "more sophisticated case-specific chemical transport models ... (*e.g.,* photochemical grid models) ...".

Commenter (0509) reminds that the EPA's Guideline on Air Quality Models (Appendix W) recommends a two-tiered approach for addressing ozone impacts – Tier 1 includes the use of technically credible relationships between precursor emissions and a source's impacts and Tier 2 includes the application of more sophisticated case-specific chemical transport models such as photochemical grid models. According to the commenter (0509) EPA's AQAT linear spreadsheet doesn't qualify as Tier 1, because it has not been published in peer-reviewed literature, nor does it qualify as Tier 2 because it does not include a photochemical mechanism.

The commenter contends that because AQAT was not evaluated against observed ozone concentrations or independent CAMx simulations, its accuracy and reliability is unknown.

Commenter (0518) insists that, although EPA asserts that AQAT is "adequate to this purpose," the Agency presents no credible evidence to this effect – *i.e.*, no evaluation of AQAT against measurements, no evaluation of AQAT against independent photochemical model simulations, and no independent peer-review of AQAT or any peer- reviewed papers on AQAT used – does not satisfy the requirements of a Tier 1 screening tool from EPA's ozone single source ozone modeling guidelines. The commenter states that the EPA failed to follow its own air quality modeling guidelines and guidance, which states that ozone models are required to have a photochemical mechanism – a feature which the AQAT does not possess, and lays out procedures for applying an ozone model, which according to the commenter EPA did not follow – *e.g.*, selecting a model that has been peer- reviewed, developing a Modeling Protocol and conducting a Model Performance Evaluation.

Different Approaches/Assumptions Used in Steps 1 and 2 than in Step 3

Commenters (0365, 0409, 0518, 0760) note that the AQAT used for this propose rule, redefined the 2026 baseline emissions (uses different approaches/assumptions), making Step 3 results inconsistent with Step 1 and 2 of the proposed rule. The commenters contend that the use of different approaches/assumptions introduced large uncertainties into the analysis that render the results technically uncertain and too tenuous to support the imposition of the proposed control measures at Step 3.

At least one commenter (0760) specifically requests that the EPA conducts CAMx modeling using the same assumptions and inputs that were used in Steps 1 and 2.

Commenter (0409) highlights that in the IPM database numerous EGUs are mistakenly presumed to be retired or idled. In comparison, the EPA's Engineering Analytics (EA) inventory contains these units.

AQAT – Different Approaches/Assumptions Used (Engineering Analytics, EA)

Commenters (0323, 0409, 0760) claim that the Engineering Analytics (EA) approach used in the AQAT results in emissions projections at individual units and facilities. In many cases, these emissions projections are distinctly different than what was generated by the IPMv6 summer 2021 reference case that was used for the 2016v2 platform and CAMx modeling. More specifically, the commenters assert that the resulting emissions budgets (post-control), at multiple units, calculated with the EA, under the AQAT approach, are found to be higher than the emissions originally used in the photochemical air quality simulations from IPM/CAMx modeling and used to prepare the calibration factors for the simplified AQAT. In a similar comment, the commenters argue that the resulting emissions budgets (post-control), in multiple states, calculated with the EA are found to be higher than the emissions originally used in the AQ modeled base case simulations and used in the calibration factors for the simplified AQAT.

Commenter (0409) states the remedy case is not reliable because it does not provide accurately modeled air quality concentration projections at the downwind receptors, due to this discrepancy EPA does not have a basis to show that this proposed FIP resolves any states' good neighbor obligations; resulting in a failed model that is not reliable.

AQAT – IPM/CAMx- Developed Calibration Factors

Commenters (0323, 0505, 0528, 0760) underscore the point that while EPA indicates that use of AQAT, with some calibration factors is "adequate" for this purpose, the EPA themselves recognize that using AQAT does not account for the impact of spatial and category specific emissions changes on downwind ozone concentrations.

Commenters (0323, 0760) observe that IPM/CAMx-developed calibration factors for AQAT to include units operating at certain levels of control or have already been retired as estimated by IPM, and these photochemical model-derived calibration factors are based on the specific emissions inventory and unit level operating conditions estimated by IPM. Commenter (0760) claims that the EPA overestimated emissions reductions by double counting reductions achieved from retired units. The commenters (0323, 0760) explain that the emissions reductions calculated under the AQAT approach include changes associated with units that have been retired in the IPM base case simulations; adding that these calibration factors are not applicable as EA generated emissions reductions cannot technically be associated with a unit that has been retired. The commenter claims that the third-party reviewer (Alpine) identified thousands of ozone season NO_X tons that the EPA includes as emissions reductions from EGUs that the EPA had already modeled in Steps 1 and 2 as having been retired in the future base case.

Commenter (0505) disagrees with EPA's assumption that calibration factors used in the EPA's AQAT is sufficient to alleviate the concerns related to the linear ozone response assumption; adding ozone response to NO_X reductions is significantly greater than the ozone response to VOC reductions for all receptor-state pairs.

Commenter (0760) claims that because the air quality modeling results from IPM are at the unit (sub-state) level to calculate significant contribution values, it is arbitrary that the EPA has selected to use an alternative emissions projection to determine an optimized control case cost which does not include the same assumptions as the air quality base case. The commenter insists that the EPA should have determined the single best way to estimate future year EGU emissions and then used that method to conduct photochemical modeling for the future case and for any potential additional controls on that future case.

AQAT – Calibration

Commenters (0323, 0760) say that the EA method ignores important source characteristics (*i.e.,* emissions from the power sector are largely from tall stacks in comparison to other types of source emissions which can be released at ground level). The commenters claim that while EPA tries to further "calibrate" the simplified AQAT to account for this discrepancy (source type and location of the emissions reductions), the matter cannot adequately be addressed without additional photochemical modeling using the unique temporal- spatial patterns of the emissions inventories consistently throughout each of the proposed rule's steps.

Commenter (0528) asserts that the simulation (the 2026 simulation in which NO_X emissions from EGU and non-EGU point sources are reduced simultaneously by 30 percent) does not reflect real-world factors that affect ozone, including the emissions source and the location of the source; instead shows significant uncertainty in the ozone impacts predicted by AQAT.

Commenter (0528) highlights that AQAT does not distinguish between Texas sources that could be over 1,000 miles apart.

AQAT– Ozone Benefits Misrepresented

Commenter (0336) states their belief that the EPA's modeling projections for 2023 and 2026 ozone air quality for certain mid-Atlantic monitors may be unrealistically optimistic. The commenter provides the Harford Country monitor located in Maryland, Air Quality System as an example – noting it has been identified with a 2020 design value of 0.072 ppm; the fourth highest, eight-hr average ozone concentration measured in 2021 was 0.073 ppm. The commenter adds that the EPA's projections in the AQAT tool show that the monitoring site will experience improved air quality such that measured values will be approximately 8-10 ppb less in 2023 than in 2021. The commenter notes that this unlikely projection allows the Harford County monitor to be labeled an attainment monitor in EPA's four step process for determining transport requirements and screens out North Carolina, which contributes more than 0.7 ppb to the Harford County monitoring site, from applicability to the proposed FIP. The commenter suggests that inclusion in this proposed transport rule will require much more stringent NO_X standards on industrial sources than would otherwise be required in many areas. Some of the proposed NO_X limitations are more stringent than NSPS requirements under 40 CFR 60. Some NSPS for the industrial units subject to the proposed FIP do not regulate NO_X at all. The commenter concludes that this proposed transport rule will place states, specifically Virginia at a significant disadvantage when competing with, for example, North Carolina for new industry and economic development.

Commenters (0395, 0528) suggest that the AQAT misrepresents the FIP's ozone benefits by as much as double. The commenters note that in the Ozone Transport Policy Analysis Proposed Rule TSD, the EPA compares the design values predicted using both calibrations (*i.e.*, modeling results from a 2026 case where NO_X emissions from EGU and non-EGU point sources were reduced by 30 percent and an alternative calibration approach based on the difference in ozone contributions between the 2026 base case to the 2023 base case), and found a difference in ozone design values as large as 0.24 ppb in monitors linked to Texas. The commenters emphasize that contrary to EPA's statement that such differences are "moderate," this difference reflects a sensitivity "almost as large as the ozone benefits predicted by AQAT." Commenter (0395) adds that the second simulation bears almost no resemblance to the reductions in NO_X budgets of the proposal, especially the reductions proposed for Texas which are much more stringent than a 30 percent reduction.

Commenters (0323, 0760) state that in 2023, the estimated ozone reductions using the AQAT approach are projected to be between 0.1 and 0.2 ppb at monitors in Texas. At least one commenter (0760) adds that in 2026 the largest reductions in ozone from the proposed control strategy are estimated at the two receptors in Texas (*i.e.*, Brazoria County and Harris County), where the average reduction is only 1.3 ppb. The commenter asserts that in place of a direct comparison of the final remedy to an air quality simulation, the EPA can only provide a comparison of various calibration factors as justification for their conclusion that the simplified

AQAT provides reasonable estimates of air quality concentration changes at individual receptors at magnitudes in the hundredths (0.01) of ppb – an infinitesimally small value.

Commenter (0528) states their belief that the EPA's portrayal of the ozone benefits of the Texas FIP reductions using a reduced-form analysis – using an ozone AQAT instead of demonstrating a source-receptor relationship through photochemical modeling, is fundamentally flawed and creates an erroneous depiction of the Chicago-area ozone benefits of Texas NO_X reductions. The commenter further states that the EPA's portrayal of the ozone benefits of the Texas FIP reductions using a reduced-form analysis is not modeling and creates an erroneous portrayal of the Chicago-area ozone benefits of Texas NO_X reductions. The EPA failed to account for the EGU reductions recently imposed by Illinois statute, the EPA's assessment of the non-EGU emissions reductions that would result from the FIP is dramatically understated, and the EPA's cost-effectiveness analysis for Texas EGUs is off by up to an order of magnitude.

AQAT – Fit-For-Purpose

Commenters (0300, 0509, 0518) maintain, in general, that the EPA is using the AQAT to an accuracy and precision for non-EGU Sources that has never been established - identify whether the change in NO_X emissions causes extremely small ozone changes (*e.g.,* 0.10 and 0.01 ppb) at downwind receptors. The commenters argue that since EPA never evaluated AQAT against observed ozone concentrations or independent CAMx simulations, its accuracy and reliability have never been demonstrated to achieve the purpose for which EPA claims to use the tool. The commenters suggest that the level of precisions/accuracy is unachievable with this tool, because ozone formation is nonlinear – and states that is why EPA's guideline and guidance provides that the EPA will use a model with a photochemical mechanism to simulate ozone. The commenters conclude that the AQAT fails a basic "fit for purpose" test as it does not include a photochemical mechanism.

Linear Relationship between NO_X Emissions and Ozone Concentrations

Commenters (0505, 0518, 0528, 0760) claim that the AQAT inappropriately assumes a linear relationship between NO_X emissions and ozone concentrations, and the EPA has provided no calculations or analysis to support this claim.

Commenter (0505) disagrees with EPA's assumptions that ozone response to NO_X anthropogenic emissions reductions will remain linear since the percent change in total anthropogenic emissions for most states considered in the various control/mitigation scenarios are only a few percent.

Commenter (0760) asserts that by calculating Step 1 and Step 2 metrics using one set of operating conditions (IPM) and then applying potential emissions reductions using an alternative set of operating conditions (EA) at many facilities in the impacted modeling domain, the EPA chooses to ignore its own recognition of non-linear ozone formation and the temporal and spatial uniqueness of emissions source impact on downwind concentrations.

Commenters (0505, 0760) disagree with the assumption that downwind air quality improvement estimated by the EPA's use of the simplified AQAT is indifferent to the source sector or the location of the emissions source within the state where the ton of emissions was reduced. Commenter (0760) notes that under the AQAT approach, for example, reducing one ton of NO_X emissions from the power and industrial source sector is assumed to have the same downwind ozone reduction as reducing one ton of NO_X emissions from the mobile source sector, and maintains that an "one-ton-equals-one ton" estimate is demonstrably false as it grossly over-simplifies the non-linear chemistry of ozone formation and change associated with emissions reductions.

AQAT – Not an Established State-of-the-Science

The commenter (0528) believes that the AQAT is not an established state of the science. The commenter contends that while reduced-form tools can sometimes be useful to evaluate or screen candidate emissions control policies, they are inappropriate for demonstrating specific, legally enforceable emissions control measures.

AQAT – Regular Updates

Commenter (0397) requests that the EPA consider developing regular (annual or biannual) updates to the current EMP, running CAMx using a future year baseline and a reduced NO_X future year reference point, and updating the AQAT for use by state planning groups. The commenter acknowledges that while this would require additional resources and a commitment from EPA staff, it would help build on recent collaborative work on the development of the 2016 EMP, while also helping state agencies with their planning efforts. The commenter maintains that by investing in this tool, the EPA and state agency personnel would continue to develop a deeper understanding of its uses and limitations and that would help focus efforts on future rulemakings by flattening the learning curve for all parties involved.

Response:

As described in Section C of the Ozone Transport Policy Analysis Final Rule TSD, AQAT is built using photochemical modeling runs and interpolates between those existing runs (using a calibration factor to examine alternative emissions estimates), making it possible to examine many more scenarios than could possibly be modeled using photochemical modeling (considering the number of scenarios as well as the time and the costs). Furthermore, commenters have not established a viable alternative for the EPA to utilize (considering the limitations described above) and for the most part did not discuss EPA's sensitivity analysis at proposal where alternative versions of AQAT were utilized demonstrating the robustness of the results. At final, the EPA has again performed numerous sensitivity analyses. For example, Section C.4 of the Ozone Transport Policy Analysis Final Rule TSD presents an analysis using the alternative calibration factor, demonstrating that our findings are consistent and robust across a range of assumptions regarding source, location, and degree of emissions changes, supporting our conclusion that the rule does not overcontrol any states).

EPA disagrees that the commenters have identified methodological errors and shortcomings that invalidate the estimates from the tool. The EPA disagrees that AQAT does not meet EPA modeling guidelines. See the EPA's discussion about AQAT uncertainties, how AQAT is directly built using CAMx photochemical modeling, peer-review, and uncertainties in Section C.5 of the Ozone Transport Policy Analysis Final Rule TSD. Commenters also failed to acknowledge the EPA's sensitivity analysis at proposal where alternative versions of AQAT were utilized to demonstrate the robustness of our results.

Nonetheless, for the final rule, in addition to continuing to rely on AQAT, the EPA performed photochemical modeling using CAMx of a Final Rule Policy Control scenario. The results of this full photochemical grid modeling run confirm the Step 3 assessment made using AQAT (see Appendix J of the Ozone Policy Analysis Final Rule TSD and the RIA Appendix 3A for details). The EPA also performed further statistical evaluation of AQAT consistency with CAMx. Averaged across all air quality monitors, the mean bias was -0.01 ppb (-0.02 percent) and -0.03 ppb (-0.05 percent) using the primary and alternative calibration factors, respectively. Collectively, these comparisons against an independent photochemical air quality modeling simulation further affirmed that a calibrated AQAT can create reasonable estimates of air quality concentrations for each receptor.

As described in preamble Section IV and in Section C.3 of the Ozone Transport Policy Analysis Final Rule TSD, the EPA used photochemical modeling to determine the set of receptors and air quality contributions for Steps 1 and 2 of the 4-step interstate transport framework. See preamble Section IV.C for EPA's discussion of why IPM and engineering analysis are used at the various steps of the transport framework and the implications for using each at the various steps.

In response to comments about the precision used within AQAT, one of the primary uses of the tool is to identify when design values drop below the 71 ppb average or maximum threshold (signifying resolution of a receptor to attainment) and when state contributions drop below 0.70 ppb (signifying a state is no longer contributing to a receptor at Step 2). We note that the EPA's truncation procedures render additional digits in the decimals moot. In AQAT, in response to emissions changes, when a value drops below the threshold values (71 ppb or 0.70 ppb), that receptor or the contribution is estimated to be resolved. The "AQAT value" and a truncated value would show identical results as the air quality values pass these thresholds. Similarly, the EPA disagrees with commenters that estimation of air quality changes based on fractional changes in emissions resulting in fractional changes in emissions should not be calculated, or that they are insignificant. Reductions in emissions, even ones representing a fraction of a percent of a state's emissions can and do result in air quality changes. These should be accounted for to ensure that the EPA does not unnecessarily undercontrol or overcontrol sources and states.

In response to those commenters who discussed the alternative and primary calibration approaches for Texas, at final, the difference in air quality estimates between the engineering base and the control case was approximately 2 ppb (the maximum DV for the primary calibration factor for the Step 3 control configuration going from 72.51 to 70.47 – see Section C.4 of the Ozone Transport Policy Analysis Final Rule TSD for details). Regardless of the uncertainty, as described above, the results of EPA's Step 3 analysis using the primary and alternative calibration approaches do not result in changes in EPA's conclusions.

The EPA disagrees that the effects of this rule are "vanishingly small" or that the improvements constitute overcontrol. As described in Section V.D of the preamble, there are meaningful improvements in ozone levels at the identified receptors under the emissions control strategy of the final rule to eliminate significant contribution. For many receptors, this rule alone will make substantial progress toward achieving attainment (as further discussed in the Air Quality Modeling Final Rule TSD and the Ozone Transport Policy Analysis Final Rule TSD).

In addition, as described in preamble Section III, the EPA has established that the 2023 and 2026 dates are the most appropriate dates for establishing the requirements of the rule as well as assessing potential overcontrol. The EPA assesses full implementation of the selected Step 3 mitigation measures in its overcontrol analysis for 2026. The notion that the EPA would need to test alternative compliance patterns available under a trading program (inclusive of the trading program enhancements) for overcontrol is inconsistent with the EPA's past practice and would undermine its Step 3 analysis. In preamble Section V.D.4, the EPA discusses the relationship between the trading program enhancements and the overcontrol assessment.

In response to the commenter requesting routine updates to AQAT, this will be taken under consideration but must be balanced with other competing claims for Agency resources. We note that stakeholders have utilized existing AQAT tools, and we expect that others could use the methodology in the future (either with existing modeling data produced by the EPA, or with their own).

The EPA disagrees with the commenter's claim that the Harford County, Maryland monitoring site should be identified as a receptor. The EPA responds to a similar comment regarding the monitor in Harford County, Maryland in Section 3.4.3.2 (Projecting Future Year Design Values Based on Actual Conditions).

10.4 Electric Reliability Concerns

Comments:

Commenter (0302) states their belief that the proposed allowance setting process includes significant reductions in state budgets as units are assumed to install SCRs will likely result in additional unit retirements, or units incentivized to not operate; resulting in grid reliability concerns. The commenter acknowledges backlogs to approve new generation additions, such that if a utility decided to retire or idle a coal unit due to insufficient ozone season allowances, which are currently set on an annual basis in the proposal, then the company would lack the time necessary to plan, permit, construct, and place a new unit in operation. Additionally, the commenter notes that the minimum reserve margin requirements as a whole may not be achieved if multiple units are required to retire or idle as opposed to installing SCRs; the alternative, according to the commenter would be to controlled outages.

Commenter (0342) asserts that the EPA's goal in proposing the proposed FIP is not to simply improve NO_X control at coal plants, but to make the allocations so limited that plants are forced to cease operating; threatening grid reliability. The commenter further argues that the dynamic budgeting process allows the Agency to look at individual plant operations year-to-year from multiple angles and arbitrarily ratchet down emissions limits. The commenter claims that units will be penalized for optimizing controls – equipment degradation naturally, slightly decreases control efficiency CE year after year. The commenter explains that when emissions are capped based on this first year of performance, there are no longer enough allocations to operate within the expected performance range of the unit. Similarly, the commenter claims that units will also be penalized for unforeseen outages, maintenance, or other work occurring during ozone season. The commenter states that in the event a unit is out of service during ozone season, that unit will no longer be able to operate at full capacity during ozone season as those corresponding allowances will be removed in the upcoming season; thus, units that have historically been reliable baseload units may no longer be available to readily support the electric grid during periods of high demand in ozone season.

Commenter (0346) suggests that generation retirements be staggered to mitigate reliability impacts.

Commenter (0351) claims that the proposed rule effect of ratcheting down Sherco 3's operational capacity to no more than 31 percent of its normal operation during the ozone season (necessary to meet the 0.14 lbs/MMBtu of NO_X backstop limit without installation of SCR) will create grid instability for MISO's service territory. The commenter asks that the EPA consider creating an exception from the backstop limit for units like Sherco 3 that have less than five years of remaining operational life.

Commenters (0351, 0361) argue that the baseline assumptions used to formulate initial state budgets contain significant errors and suggests that grid reliability will increasingly be threatened as allocations are arbitrarily removed from the program. Commenter (0361) predicts that the ratcheting down of budget allowances over time without any mitigation measures taken to account for overcontrol, will lead to excessive allowance shortfalls – at a time where there are significant pressures on capacity prices in the Midwest, and specifically in MISO. The commenter observes that reliable coal-fired EGUs have been retiring at a rapid pace, and the resulting shortfall of baseload and dispatchable generation has been noted by federal and state officials and discussed in detail by MISO. Commenter (0351) claims that the EPA's analysis of the cost of controlling emissions, pursuant to the proposed backstop limit, did not consider the extent to which economic impacts (*e.g.,* an auction rates increase due to capacity availability shortage) electric generation and the transmission industry, nor did the EPA consider the reliability impacts associated with the near-term loss of unit capacity (Sherco 3), in a newly constrained MISO region.

Commenter (0361) maintains that the EPA fails to consider the impact of other existing or upcoming regulations on the energy sector and emissions reduction efforts — *e.g.,* the reconsideration of Effluent Limitation Guidelines, CCR approval processes, reconsideration of the NESAP, and announced regulations governing Greenhouse Gases; further pressuring for the retirement of these facilities in combination with slow and costly processes to bring new generation on-line increase the risk of generation shortfalls and reliability events

Commenter (0361) states that supply chain issues and restrictions on importing solar panels is making it increasingly difficult to bring new intermittent resources onto the grid; impacting the timetable. According to the commenter, these factors brought on by certain provisions of the Proposed Rule will result in serious increases in reliability risks and significant costs to consumers – but not in significant emissions reductions, particularly in the case of small generators (generators below 100 MW). The commenter concludes that the tightening allowance budget and command and control post- combustion measures will impose costs—both to EGUs and the grid more broadly—that will far exceed the proposal's benefits.

Commenter (0372) asks that additional time be allotted to adequately plan and transition energy resources – new generation must be planned, engineered, permitted, and built. The commenter fears that if the proposed rule is finalized, as written, then grid stability and reliance are dangerously at risk, especially if fossil generation is forced offline prematurely, without adequately replacing generation. The commenter claims that existing fossil-fuel generation units are needed, in the state of Kentucky, to help address the growing demand for energy and the increasing demand for economic developments, as Kentucky transitions to new energy resources. The commenter suggests that the EPA underestimated the amount of allocated allowances and asks that the EPA credit EKPC with the ozone season allocations it needs to ensure their continued ability to deliver reliable generation.

Commenter (0372) believes that the proposed rule allots insufficient time for RTOs to process unit deactivations, which take time to maintain grid reliability; noting that the proposed FIP implementation begins in less than a year for the 2023 ozone season and ask that the EPA work with and seek input from appropriate parties (including independent grid operators, like PJM) before finalizing the proposed rule. The commenter provides a short summary of their deactivation process that focuses on ensuring no transmission reliability criteria violations result from generation deactivation. The commenter expresses concern that the potential for multiple generators impacted by the rule to deactivate almost simultaneously may result in resource adequacy issues or other operational challenges, due to the loss of the operating characteristics of those resources.

Commenter (0394) worries that shortfalls in allowances will hinder the ability for energy providers to meet their customers' demands for electric power, and also hider their ability to maintain system reliability beginning in ozone season 2023, if the rule is promulgated with emissions budgets consistent with those set out in the Proposed Rule. The commenter recalls (along with commenter 0323) that the Technical Report estimates an allowance shortfall of 6,310 allowances within the nine states examined during the 2023 ozone season. The commenters expect allowances that are available on the market to be priced high due to market conditions resulting from tightness in state budgets where there are expected to be small allowance surpluses, and the constrains on trading that the EPA proposes to implement. Commenter (0394) warns that Kentucky and Texas are expected to experience substantial allowance shortfalls in 2026, totaling 4,119 tons and 8,780 allowances respectively, even as ozone season emissions decline. The commenter further warns that the effective allowance emissions rates for EGUs in these two states, coupled with allowance shortfalls, will constrain unit operations in these two states and may result in electric reliability issues, which will be exacerbated by the need to retrofit 79 units, totaling 42 GW of coal-fired capacity in the 25 states covered by the Proposed Rule with SCR by the start of the 2026 ozone season – including 25 units in Kentucky and Texas alone, representing a total of 11.8 GW of capacity.

Commenter (0394) expresses their concerns that allocated allowances under each state's emissions budget proposed standards are too stringent and may result in units shutting down on a scale and schedule that will not allow the remaining fleet capacity to keep pace with electricity demands – a problem driven in large part by incorrect technical and base case modeling assumptions. The commenter provides an excerpt from the commissioned report (showing public power operating coal capacity, amount of public power coal capacity idled by IPM in a run year, cumulative coal retirements modeled by IPM and IPM modeled coal to gas [C2G] conversions) that evaluated how EPA's IPM v6 Summer 2021 Reference Case treated public power utilities. The commenter recommends that the EPA review and revise its Reference Case to reflect correction in which units will actually retire or become idle. The commenter mentions that the EPA's proposals to limit use of Group 2 allowances banked prior to 2023 and to recalibrate the number of banked allowances available for use on an annual basis exacerbate the problem - allocation of inadequate numbers of allowances to public power EGUs. The commenter expresses concerns that they will not be able to buy Group 3 allowances, particularly as the bank is recalibrated, and as a result, be left without a means to meet their customers' electricity demands, while also complying with the rule. According to the commenter, CSAPR ozone-season NO_X allowances were trading up to $30,000 per ton (at the time of the comment period), which the commenter asserts is an exorbitant price for any utility, but astronomical for public power. The commenter highlights the fact that the EPA is selecting to penalize providers for non-compliance and expresses concern that as a nonprofit they will not be able to pay penalties on this scale, nor handle compliance costs; resulting in reliability issues particularly by EJ communities.

Commenter (0400) suggests that the lack of allowance liquidity and price escalation that has occurred since the FIP was first proposed, will result in down-dispatch of significant components of the coal and gas fleets by the first compliance date (2023), thereby thinning already small reserve margins and further exposing markets to reliability risks. The commenter contends that the proposed rule simply does not provide enough time for generation owners, states and (where applicable) RTOs/ISOs to coordinate compliance in a way that will allow reliability impacts to be considered and mitigated; adding that reliability will be exacerbated in 2024-25 by retirement/idling decisions forced by the downward adjustment of budgets as part of the dynamic budget setting process for all units and the daily backstop emissions rate for SCR-controlled units.

Commenter (0408) is concerned that they will not be able to provide reliable energy to customers; noting that the dramatic contraction of emissions allowances may lead to a potentially unbridgeable gap in resources through idling or retiring non-SCR units, because SCRs installation would be either not economically justified or could not be timely installed if, for example, PSD permitting is required. The commenter adds that the idling or retirement of non-SCR units without replacement generation would result in a reserve margin well below target range. According to the commenter, forced idling of non-SCR units in ozone season has serious reliability implications. The commenter announces that, in their case, the forced idling or retirement of non-SCR units in the fleet would be equivalent to 782 MW of their currently planned 7,727 MW system capacity by 2026 – compounded further by forecasted load growth on their system and a loss of capacity that would result in a drop below the target reserve margin range needed to reliably meet the needs of the service territory, as set forth in the commenter's Integrated Resource Plan, which is on file with the Kentucky Public Service Commission. The commenter asserts that the loss of an additional 782 MW of non-SCR capacity at risk in the fleet as a result of the proposed GNP would place the system 493 MW below the current minimum summer reserve margin target and considering the forecasted load growth as well as planned solar resources, by 2026, the minimum summer reserve margin deficit is estimated at 582 MW. The commenter warns that this low level of reserve margin is likely to lead to periodic Energy Emergency Alert notices per the NERC, and ultimately rolling blackouts in served communities.

Commenters (0409, 0411) assert that the proposed FIP must include provisions that allow for emergency dispatch of resources in the event of grid reliability issues, without penalty to the generating source – *i.e.*, when an emergency is declared, the duration of the event should be exempt from being counted towards a unit's ozone season budget, and the backstop limit provision should not apply. As renewable resources are added to the electric grid, the commenters express concern that energy shortages (within an already constrained electricity market, undergoing unprecedented changes) will be compounded in upcoming years, due to limited allowance allocations under this proposal. Commenter (0411) suggests that the number of emergency events are becoming more frequent with the volatile weather patterns experienced in recent years combined with increased load from the electrification of the transportation sector, industrial processes, and space heating. As an example, the commenter mentions unit derates and operational limitations due to thermal discharge limitations, during the 2021 summer months. The commenter offers the following suggestions to address allowance allocation concerns:

1. Include a reliability safety exception for announced NERC Energy Emergency Alert 2 (EEA2). These alerts are issued by the Reliability Coordinators and are not in the control of the operating company. The exception would allow all units to operate if an EEA2 is declared by the Reliability Coordinator and not be required to surrender allowances for the duration of the EEA2 conditions.
2. Clarify that the backstop limit does not apply during any announced NERC EEA2 alerts.
3. EPA should confirm that facilities must still comply with all other applicable emissions limits in their air emissions permits during EEA2 events. If dynamic budgeting is retained in the final rule, the EPA should clarify that emissions during EEA2events will be considered in the dynamic budgeting process for future year emissions allocations.

Commenter (0411) believes that the development of the allowance market via dynamic budgeting, the 10.5 percent budget cap, and backstop limit requirement will create ongoing, allowance market uncertainty affecting both the cost and availability of allowances; impacting the number of fossil-fueled units available to operate to meet load needs. The commenter questions the ability to purchase allowances on the market; claiming that the EPA underestimated the amount of allowances needed (for units in Wisconsin, Minnesota, and Texas) by 40 percent – *i.e.,* allowance allocation equals 60 percent of anticipated needs. The commenter contends that without adequate allowances, given the already difficult reliability situation reported by NERC, units may be unavailable for a significant amount of the ozone season since operators will not be assured that needed allowances can be found at any price thus forcing units offline to ensure compliance.

Commenter (0431) states that the presumed assumption by the EPA that all coal-fired units greater than 100 MW that do not currently have SCR technology installed will install such technology prior to the 2026 ozone season, results in a massive drop in the Arkansas state ozone season NO_X emissions allowance budget allocation in 2026 and beyond. According to the commenter this assumption is flawed because (1) there are four large EGUs in Arkansas that have federally enforceable dates to cease to use coal that will occur before the end of 2030. It is very unlikely that the owners of those units would choose to invest in expensive control devices such as SCR with only a few years remaining of coal-fired operation; and (2) This assumption is being made by the EPA without taking into account the remaining useful life of the EGUs and construction delays associated with the COVID19 pandemic, labor shortages, supply chain delays, a limited amount of engineering support to design the SCR retrofits, outage coordination to prevent electricity shortages, and the ongoing war in Ukraine. As an example, the commenter notes that at least 2 of their units (Unit 1 and Unit 2 at the White Bluff Steam Electric Station) are required to cease to use coal and based on their remaining useful life, these units are not logical candidates for SCR additions. Instead, the commenter notes that they are in the process of planning new generation to replace this generation by the end of 2030. The commenter warns that without some type of exemption from the proposed FIP, recalibration of the Arkansas state emissions allowance budget assuming typical operation of these units, and/or flexibility with the proposed CSAPR enhancements, idling of these units may be forced during ozone seasons in 2026 and beyond. More specifically, the commenter requests that the Flint Creek Power Plant (Flint Creek) near Gentry, Arkansas be given an exemption from the proposed FIP and/or flexibility with the proposed CSAPR enhancements, due to the areas significant role in providing electric grid reliability.

Commenter (0531) claims that the use of BACT equivalent emissions rates in the proposed state budget-setting process (along with active budgeting) resulted in tight allowance budgets, limiting EGUs’ ability to comply and create banks of allowances to provide excess allowance capacity to serve load – working to create a ceiling on the amount of load that CSAPR EGUs will be able to serve during any ozone season as CSAPR prohibits emitting more NO_X tons than a utility holds in allowances. According to the commenter, generation shifting and switching to lower emitting units is not an option when those units are limited either because they are intermittent resources (*e.g.*, wind turbines) or because they have environmental limitations (*e.g.* PSD limits on peaking resources). The commenter further notes that during the ozone season, at times, all available generation is called to operate to serve peak loads and worries that generators that do not hold enough allowances will not be available to serve needed loads. The commenter contends that the difficulty in transitioning to a cleaner more diverse generation portfolio cannot happen overnight, let alone within three years, and expresses concern that generators will need to balance the considerable cost of SCRs meeting BACT emissions rates with early retirement and/or load reductions to stay under allowance allocations/budgets.

Commenter (0531) argues that the resulting shortfalls from EGU owners unable to install enough SCR in time to meet the 2026 state emissions budget will impact the ability of EGUs (critical load serving entities) to serve the demand for power during high energy demand days. According to the commenter, in instances where units cannot achieve the BACT level NO_X allowance allocations the shortfall in allowances will have to be offset by reducing summertime generation, which is problematic for grid reliability as shortages in summertime capacity already exist in several areas of the country, including within the MISO.

Commenter (0533) suggests that the EPA consider factoring in evolving technologies and studies as they become available, if EPA plans to revisit the state budgets annually, or on a multi-year basis as the Class of '85 has proposed.

Commenter (0533) suggests that the EPA's assumptions that "large" coal-fired EGUs of 100 MW or greater will install SCR technology and meet an emissions rate of 0.05 lb/mmBtu, that coal-fired EGUs of less than 100 MW capacity and CFBs will install SNCR technology and achieve a 25 percent and a 50 percent reduction in emissions rates, and that oil- and gas-fired steam boilers of greater than 100 MW that historically have emitted at least 150 tons of NO_X per ozone season will install SCRs and meet an emissions rate of 0.03 lb/mmBtu are flawed; noting that the Agency fails to consider planned retirements, fuel conversions, and other constraints (*e.g.*, space limitations at a plant site) when developing 2026 budgets. The commenter worries that these flawed assumptions will lead to constrained state budgets that will, in turn, affect grid reliability. In a similar comment, commenter (0340) implies that the above-mentioned requirements will effectively force affected units to install new SCR controls, find other means of compliance, or retire; further arguing that by imposing limits (daily emissions rate) EPA is dictating which EGUs will continue to operate, and which ones will be shuttered. The commenter adds that, in the case of Kentucky, roughly 600 MW will need to be replaced or maintained by controls; adding that most of these units are nearing retirement, further limiting compliance options and likely leaving these units stranded. In short, the commenter states that the EPA's extremely short timelines for installing controls or replacing generation from its "third-party global engineering consulting firm" report are not applicable to Kentucky and many other states; jeopardizing the reliability of the electricity grid.

Commenter (0533) maintains that there are situations where the installation of SCRs would not be economical and suggests that many of these units would retire before incurring such capital expenditures. The commenter emphasizes that the point of a cap-and-trade program is that the affected sources can choose the most cost-effective units to overcontrol and allow expensive or technologically infeasible units to operate with lesser or no controls while meeting the overall state emissions cap. The commenter warns that if EPA sets the state budgets based using the proposed emissions rates and ignores individual circumstances at EGUs that may make achieving such emissions rates infeasible, they will eliminate the very mechanism that makes trading programs an efficient method of achieving the most cost-effective emissions reductions.

Commenter (0546) suggests that prior to issuing a final FIP, the EPA should evaluate available historical generation data for nuclear, hydroelectric, and other zero-emitting generation sources and assess whether the proposed FIP provides for adequate allowance availability in the event that a large zero- emitting unit is unavailable during the ozone season and additional fossil fuel-fired units are operated to meet electrical demand. The commenter states, to the extent, individual generating units dispatch at any given time is a function of the total electrical system load, the other generating units available to meet that load, and the relative cost of each available generation source. The commenter suggests that the EPA considered the implications of the interrelationships between zero-emitting generation and fossil fuel-fired generating units, particularly as zero-emitting generation resources become more important to the overall functioning of the CSAPR emissions trading program. The commenter discusses the reliability of some zero-emitting generation units (a nuclear or hydroelectric unit); noting that when these units are not available during a portion of the ozone season, other units (often fossil fuel-fired generating units) are needed to meet system reliability needs and electrical demand. The commenter maintains that the EPA's dynamic approach for establishing state emissions budgets (under the proposed rule) produce inflexible state emissions budgets, by imposing historically stringent limits; resulting in a scenario where sufficient allowances would simply not exist to accommodate the need to run a higher-emitting unit to meet electrical demand during a period in which a zero-emitting generation resource, which typically operates to serve a portion of total electrical system demand, is unavailable.

Commenter (0546) also proclaims that the EPA must consider the impacts of severe weather events (that occur during the ozone season and create irregular conditions for the bulk electric system in the regions impacted) when establishing state NO_X emissions budgets under the proposed dynamic budget approach. The commenter highlights that severe weather events can cause widespread power outages, which temporarily limit electrical system demand, and can directly damage EGUs that may remain out-of-service until the necessary repairs can be completed. As an example, the commenter described their experience dealing with severe weather (hurricanes and tropical storms) that occurred during the 2020 and 2021 ozone seasons, impacting their state of Louisiana. The commenter notes that storms in 2020 caused damage to the electrical system in southwest Louisiana, creating anomalous system conditions in Louisiana for much of the 2020 ozone season. Similarly, experiences felt in 2021, according to the commenter, after Hurricane Ida rippled across the Louisiana. The commenter recommends that the EPA not rely solely on historical unit operating and emissions data from a single year where such severe weather impacts or other anomalous events may have occurred, when establishing state NO_X emissions budgets, but instead, modify the proposed dynamic budget approach to consider multiple years of historical operation data in setting any state budgets. The commenter further asks that the EPA refrain from adjusting state budgets annual and instead should adjust them every three years. The commenter also recommends that the EPA consider potential impacts of severe weather events on low- or zero-emitting generation sources, resulting in additional dispatch of higher-emitting units to meet electrical demand.

Commenter (0554) express concerns that the EPA's proposed FIP emissions control installations, idling or retirements and replacements requirements, which are to occur simultaneously across a significant number of units over the course of three years, with corresponding reductions in the energy and services these units supply to the grid, will place energy supply and reliability in jeopardy. The commenter adds that each SCR installed would require a 6-week outage; noting the potential combined 84 total weeks of outages before May 2026 would present its own set of concerns for grid reliability. The commenter notes that the EPA estimated that approximately 18 GW of coal-fueled generation and 4 GW of gas steam generation would retire by 2030 as a result of the Proposed Rule. The commenter suggests companies they oversee will be heavily impacted by the proposed rule and questions the grid's ability to sustain the impacts of such significant generation going offline over such a short time frame without reducing the stability of the grid. Moreover, the commenter contends that the compliance timeline in the Proposed Rule does not allow sufficient time to replace capacity and energy from affected EGUs that would need to retire, sit idle, or continue operating at significantly reduced levels if SCR cannot be timely installed, nor is the timeline sufficient to make the transmission upgrades needed to add new resources and maintain reliable grid operations in the face of accelerated retirements or reduced operations from coal facilities.

In a similar comment, commenter (0554) disagrees with EPA's approach to reduce ozone season NO_X budgets – an approach the commenter insist would result in an increase in ozone forming pollutants/emissions (especially during ozone conducive conditions) due to the likely increase in grid emergency events. The commenter clarifies grid operator tend to rely on load modifying resources and demand response to address emergency events, which may require the use of less controlled units (not included in the CSAPR program). To illustrate, the commenter recall, under Step 3, in the case of MISO, EGUs and other Load Serving Resources must request waivers of emissions limitations that are preventing increased generation. When under Step 3, the commenter explains that emergency event generators with environmental restrictions must request waivers of emissions limitations to maximize generation, consequently, compliance with ozone standards and other NAAQS can be jeopardized as a result – *i.e.*, result in negative environmental impacts, in addition to the negative effects associated with load shedding (brownouts). According to the commenter, by constraining ozone season budgets to BACT emissions levels, the EPA is restricting the ability of CSAPR EGUS to serve load; forcing units to either meet BACT emissions levels on a continuous basis or retire as the dynamic budgeting and active banking provisions will increase the stringency of the CSAPR program tremendously – shortening allowance allocations under EPA's proposed rule, while simultaneously increasing prices. The commenter adds that the current Group 3 NO_X Ozone Season Allowance is priced at $25,000 per ton indicating that when allowances are further reduced by the proposed rule, allowance prices will most likely increase further. The commenter maintains that increases in prices will make EGUs cost-ineffective and force many of these units that are already near retirement to retire early further exacerbating the capacity shortfalls in CSAPR states like Missouri and Illinois. The commenter concludes that the proposed FIP will restrict and prevent CSAPR units from meeting load demand during high energy demand days resulting in more grid emergencies and will thereby result in increased NO_X emissions during these periods. Since grid emergencies are likely to coincide with ozone conducive conditions, the commenter warns that the proposed FIP may result in an increased ozone formation as a result of the emissions from other non-CSAPR generating sources; contrary to EPA's stated goal of reducing NO_X transport to eliminate contributions to high ozone events.

Commenter (0557) argues that limiting future emissions to levels commensurate with a single, past ozone season (2021) ignores states, like Virginia project future demand grow, which is particularly problematic especially as electric cars and building technology shift away from fossil fuels. The commenter recommends that the EPA build a growth factor into EGU state budgets to account for growing economies and associated electricity demand.

Commenters (0286, 0317, 0323, 0348, 0355, 0359, 0365, 0372, 0373, 0375, 0394, 0395, 0400, 0408, 0409, 0414, 0431, 0499, 0529, 0533, 0546, 0550) are highly concern over EPA's assumption that new SCR installations largely will occur in the Midwest and the South—with most in the Midcontinent Independent System Operator ("MISO") region, largely because this region is already expected to experience shortfalls in capacity in the upcoming years even before the proposed FIP is implemented, and many of the commenters fear that the rule will only exacerbate current reliability issues. More specifically, commenter (0372) notes that since 2015, MISO has retired numerous coal-fire units (18,300 MW of capacity); resulting in a decline in accredited generating capacity to the extent that the comment expects grid operators to order temporary electricity blackouts. The commenter quotes MISO, "Although installed capacity has increased in the last five years, accredited capacity has decreased due to thermal retirements and the increasing transition to renewables" – a problem likely to become more serious as additional units retire. According to commenter (0373) the MISO capacity shortfall expected in 2024 is over 560 MW, assuming identified retirements were to occur without additional new generation resources (on top of the 8 GW already under development for interconnection by 2024). At least one commenter (0373) argues that compulsory retirements intended by the FIP are reckless and should be rejected.

Commenters (0302, 0333, 0346, 0354, 0355, 0361, 0370, 0372, 0375, 0385, 0395) worry that the retirement of capacity at a time when many are experiencing capacity constraints, increases the risk of a load shed event. In general, commenters stress the need for and importance of having a diverse mix of resources (for generation), including coal-fired, natural gas, nuclear, solar, and others, and insists that expediting coal closures by encouraging generation shifting, increases the grid's reliance on natural gas and could make the grid more vulnerable to future severe weather events. To illustrate concerns, commenters cited human-health impacts and/or high costs felt as a result of the February 2021 winter weather event (the Winter Storm Uri) – a severe weather event where Texans suffered widespread, extended disruptions in electricity and natural gas services.

Commenter (0395) states that significant shutdowns will occur, and even more resources will be offline during summer months as predicted by the proposal; however, the EPA woefully overpredicts the number of facilities that will retrofit SCR on an existing plant and underpredicts the number of plants that will be forced to shut down due to this Proposal. The current electricity market is already undergoing a market-based shift toward renewable resources and away from fossil fuel. Existing coal-fired generating capacity has declined from more than 300,000 MW in 2010 to slightly more than 200,000 MW in 2022. Further regulation of coal-fired power plants will impose grid reliability risks.

Commenters (0323, 0531) state that the Midcontinent ISO (MISO) faces a capacity shortfall (as reported in the 2018 and 2021 LTRA) in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions. Commenter (0531) notes that load serving entities in 4 of 11 zones entered the annual planning resource auction in April 2022 without enough owned or contracted capacity to cover their requirements. The commenter explains that peak demand projections (in the area) have increased by 1.7 percent since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. The commenter expresses concern that MISO has experienced a drop in generation capacity in the amount of 3,200 MW or 2.3 percent, than in the summer of 2021; resulting in system operations needing to employ operating mitigation practices – *e.g.,* load modifying resources to meet reserve requirements under normal peak summer conditions.

Commenters (0333, 0354, 0370, 0375, 0385) remind that in recent years, SPP (which includes ERCOT and AECT members) has experienced capacity shortfall issues during peak conditions (*e.g.*, during Winter Storm Uri in 2021) and assert that these issues will only worsen if the prosed rule is finalized. According to commenter (0333), they expect the Planning Horizon for new transmission (within the SPP market) to take up to ten years; limiting the ability to plan for and construct additional transmission by 2026 to mitigate the effects of the significant loss in thermal generation that is expected as a result of this rule. The commenter concludes that sufficient time has not be allotted to adequately study and fully analyze all of the potentially significant reliability impacts of this rule. The commenter mentions that Entergy Texas Inc. is a majority-owned subsidiary of Entergy Corporation (Entergy) which operates in the MISO region (specifically Arkansas, Louisiana, Mississippi, and Texas), and notes Entergy Texas Inc.'s concerns, many of which resemble concerns (*e.g.*, forced early retirement) already highlighted by MISO and ERCOT.

Commenters (0333, 0394, 0395, 0434, 0550) maintain that the proposed rule will have serious reliability consequences for the ERCOT grid. The commenters note that in the ERCOT region, transmission expansion projects to add intermittent resources are being monitored for delays or cancellations, which could contribute to local reliability concerns; outcomes that were not considered by the proposed FIP. In general, commenters indicate that a preliminary analysis of the potential effect of the Proposed Rule on ERCOT in 2026 identified the following four areas of concern to maintain reliability:

1. The steady state transmission analysis found an investment of $1.2 to $1.5 billion is needed to maintain local reliability of the transmission system, and an additional $2.7 to $5.2 billion of transmission improvements would be needed to improve the ERCOT regional transfer capability after the retirement of the Proposed Rule's affected generation;
2. The probability of load sheading during the summer of 2026 increases almost nine times by 8 pm if 10,800 MW of affected generation retires;
3. ERCOT will only be able to approve one third of the expected maintenance outages required by the remaining thermal units in 2026, which will likely result in an increase in forced outages of these remaining units, substantially increasing the likelihood of grid instability, and further increasing the need for firm load shed to avoid total grid failure; and
4. The loss of the affected generation will reduce the gross inertia capacity of the system by 13 percent. This will likely result in increased out of market instruction by ERCOT to maintain minimum amounts of inertia needed to maintain reliability (inverter-based generation, such as wind and solar, do not supply inertia).

In a similar comment, commenters (0333, 0434) express concerns that the proposed FIP mandates that owners of certain EGUs install SCR technology by 2026, which would be prohibitively expensive and likely lead force these owners to prematurely retire units. In the ERCOT region, the commenters expect upwards to 10,800 MW of capacity to be impacted – 8,200 MW of coal-fired generation and 2,600 MW of gas-fired generation; potentially imposing catastrophic consequences for the electric grid. The commenters momentarily discuss several potential impacts associated with the retirements of these units – *e.g.,* increases in probability that generation owners will need to direct utilities to shed firm load (*i.e.,* to disconnect customers from the grid).

In a similar comment, commenter (0333) asserts that the proposed rule is incompatible with the current state law (Texas, Senate Bills 3 and 1281) and efforts, by the commenter, to improve reliability in the ERCOT region by prematurely forcing the retirement of significant amounts of dispatchable generation that are critical to the provision of reliable electric service to millions of Texas customers. The commenter mentions they are currently exploring ways to encourage the addition of new dispatchable generation in ERCOT in response to the February 2021 Winter Storm Uri. The commenter states, Senate Bill 1281 requires ERCOT to conduct a biennial assessment of the ERCOT power grid to assess the grid's reliability in extreme weather scenarios, and Senate Bill 3 requires the establishment of requirements to meet the reliability needs of the ERCOT power region, that "winter resource capability qualifications for [ancillary or reliability services] include on-site fuel storage, duel fuel capability, or fuel supply arrangements to ensure winter performance for several days, the establishment of weatherization requirements for both generators and transmission and distribution utilities, and ERCOT to review, coordinate, and approve or deny request by providers of electric generation service for a planned power outage during any season and for any period, as well as enhance the requirements for the maintenance and evaluation of emergency operations plans and extend the applicability of these requirements to over 800 utilities, generators, and other market participants across the state. In response to the legislative mandates for additional dispatchable generation in ERCOT, the commenter states that they selected to pursue a two-phase blueprint for ERCOT market redesign (Phase I and II). The commenter explains that Phase I includes shorter term changes to the ERCOT market to incentivize existing dispatchable generation to operate, and Phase II involves "long-term market design reforms to promote the supply of dispatchable generation and develop a backstop reliability service." Under Phase I, the commenter notes that they adopted changes (*e.g.,* to the minimum contingency level, etc., intended to incentivize existing dispatchable generation to deploy sooner in times of rising customer demand) to the operating reserve demand curve (ORDC) – a scarcity pricing mechanism that is intended to incentivize a range of market responses, including bringing on all available dispatchable generation such as gas and coal plants, to meet the increased electricity demand. For Phase II, the commenter states they developed a set of broad principles defined in the market design blueprint [in Project No. 52373], which include exploring market-based incentives, mechanisms, and methods of "ensuring the supply of dispatchable generation is sufficient to meet system demand in ERCOT."

Commenter (0340) supports the reduction of GHG emissions, however, expresses concern that potential increases in NO_X emissions from GHG controls will present problems for facilities that are subject to the strict limits of this proposed FIP; resulting in the shutdown or the early retirement of EGUs necessary for grid stability and reliability. Furthermore, the commenter states that potential changes to the EPA's Effluent Guidelines and the CCR rulemakings will have additional impacts to the electricity sector. The commenter recommends that the EPA re-evaluate the timing and necessity in the promulgation of multiple rules that impact the same facilities in the same time frames, as well as the potential cost and benefits of overlapping rules.

Commenters (0346, 0409) worry that the proposed FIP, as written, will the forced retirement of 79 EGU units (42 GW of capacity) within condensed window. The commenters state that they account for roughly 4,868 MW (16 units) of that capacity – a lost in capacity that spans over state lines and RTOs. The commenters (along with commenter 0400) underscore the point that installing control devices on smaller emitting units is cost prohibitive, and even if costs could be absorbed, the timeframe allotted is insufficient to complete the projects. At least one commenter (0346) claims these factors almost certainly solidifies the outcome that units with a capacity less than 100 MW will not be on-line during ozone season 2026. Commenter (0346) explains that if non-SCR units cannot run for five months out of the year (May through September) – the overhead required to run the units for just seven months in the non-ozone season will not justify continued operation.

Commenters (0346, 0409) argue that existing coal-fired generation cannot make up the non-SCR EGU shortfall resulting from proposed FIP provisions, and it is unclear, under the proposed rule, how these shortfalls in generation will be covered. The commenters further assert that the Proposed Rule aims to push fossil generation – particularly coal-fired EGUs – offline; impacting grid reliability, especially during hot temperature days and times of extreme weather events (*e.g.*, hurricanes), which place a strain on reliability. Commenter (0346) includes a number of tables and graphs as support, in their comments.

Commenters (0348, 0412) argue that the proposed FIP does not address the challenge, and impacts, of maintaining resource adequacy for the power grid. The commenters define resource adequacy as the ability of the electric system to supply the aggregate energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. Commenter (0348) observes that the traditional dispatchable generators targeted by this Proposed Rule tend to have much higher accredited capacity than the replacement capacity that has been brough on-line in recent years (wind and solar). Commenter (0348) notices the MISO is experiencing a trending decline in reserve margin, which is largely the result of the retirement of significant amounts of dispatchable generation – a situation that is likely to be accelerated by the proposed FIP. The commenter explains that the replacement of retiring generation with new, mostly non-dispatchable facilities that are not installed at the same time or valued at the same output presents its own risks, because the construction of new generation is often a lengthy and costly process. The commenter (0348) points to 3 economic analyses prepared (based on EPA assumptions) that assesses the impacts of retirements and retrofit units for 2026 and found that an increase in the number of hours of energy inadequacy of between 16 times and 80 times the base case due to the Proposed Rule.

Commenters (0359, 0372, 0382) are deeply concerned over the amount of projected capacity loss from retirements of non-intermittent power (18 GW of coal retirements are projected by 2030). Commenter (0359) references the article titled, "Grid Operators Underscore Utilities' Reliability Fears Over EPA's CCR Plans" that discussed the submittal of comments from regional transmission organizations (RTOs) filed regarding CCR rule extensions that could result in the loss of 3.1 GW of capacity within MISO. The commenter mentions that the PJM Interconnection, LLC which coordinates the movement of wholesale electricity to ensure reliability for over 65 million people in the Eastern and Midwest states also identified concerns resulting from the ripple effect resulting from reliability concerns within the MISO region. The commenter (along with commenter 0396) references articles published in Power Magazine as additional support. Commenter (0359) suggests that the EPA evaluate the possible overcontrol of the electricity sector and the potential impacts to the electric grid; adding that the proposed FIP is projected to displace approximately six times the capacity that is currently raising serious electrical grid reliability concerns from two of the major RTOs.

Commenter (0370) expresses concern that any reduction in operations will pose a threat to reliability in the form of reduced generation capacity. The commenter clarifies that for covered EGUs currently without SCRs to comply with the Proposed Rule's requirements, the associated owners will have to take one or more of the following actions: purchase emissions allowances as part of the trading program described in the Proposed Rule, install SCRs, operate the EGU at a reduced capacity, or retire the EGU. The commenter mentions an analysis performed (by the commenter) indicates two factors: (1) Planning Reserve Margin (PRM) requirement is expected to increase to 15 percent (from 12 percent), which means that the SPP BAA PRM projected for the 2027 Summer Season would not meet the minimum SPP PRM requirement; and (2) these projections do not consider any impacts the Proposed Rule's requirements will have on operating capability from thermal resources, impacts that could be felt as soon as 2023 and certainly by 2026.

The commenter (0370) recognizes that while some coal and gas resources may be able to operate at the needed capacity within budgeted allowances without additional reduction measures, it is clear that others will need to install SCRs to meet the Proposed Rule's requirements. Even when one considers potential additional capacity from generation facilities currently in the SPP generator interconnection queue, the commenter fears several thousand MW of coal generation capacity will be at risk when 2026 emissions budgets reach levels based on what would be achieved with SCR installation.

Commenter (0372) believes that the proposed rule will lead to a decreased capacity if finalized and is concerned that there is not sufficient time allotted for RTOs to process unit commissioning replacements – replace lost generation – which takes time to maintain grid reliability. The commenter highlights that the proposed FIP implementation begins in less than a year for the 2023 ozone season and ask that the EPA work with and seek input from appropriate parties (including independent grid operators, like PJM) before finalizing the proposed rule. The commenter asserts that any new proposal to add generation must be studied to determine whether any transmission grid reinforcements must be constructed prior the generator injecting power into the grid. According to the commenter, regions have been very successful in incentivizing generation developers to propose projects, but there is a large accumulation of projects in the queue. The commenter emphasizes that the magnitude of interconnection requests and the inefficiencies inherent in the interconnection processes severely delays the timeline for bringing a new resource on-line; adding that FERC requires RTOs to provide updates on their efforts to manage the bottleneck of interconnection requests when RTOs have 25 percent or more requests backlogged in the process. The commenter mentions that they filed the required report on the status of the interconnection queue with FERC (2,494 active projects, representing approximately 226.5 GW).

Commenter (0385) believes that this rule threatens to force San Miguel offline, exacerbating known localized grid concerns – a decision that the commenter feels is unwarranted, especially as impacts from extreme weather events (hurricanes, droughts, etc.) continue to test/strain grid reliability, the commenter worries that the proposed rule will reduce capacity from key resources (*e.g.,* coal) that can respond during extreme weather events.

Commenter (0394) questions EPA's decision to engage in power generation shifting and idling. The commenter (along with commenter 0286, 0323, 0348, 0396) quote, Clair Moeller, MISO President and Chief Operating Officer, "…..zones that do not have sufficient generation to cover their load plus their required reserves.….will have increased risk of temporary, controlled outages to maintain system reliability" and customers in those zones "may also face higher costs to procure power when it is scarce." Commenters (0323, 0396) add that capacity shortfalls were reflected in the market pricing for the capacity – *e.g.,* clearing prices have surged from $5 to nearly $237 per megawatt-day, in a single year. According to commenter (0396) this price increase is because there were more capacity retirements during the year than there have been for several years. The commenter fears, in general, that the underlying source is an industry already engaging in a transition that may be proceeding too quickly.

Commenter (0400) asserts that the proposed FIP is an attempt by the Agency to relegate coal-fired generation as the proposed allocation budgets would plummet by 2026 – forcing, even well-controlled coal-fired units with SCR controls to operate at reduced capacity factors due to the scarcity of NO_X allocations. In addition, the proposed and overly stringent enhancements leave no room for flexibility, forcing technology installations or retirements if the utility cannot afford the retrofits.

In a similar comment, commenters (0400, 0409) claims that a product of the FIP's methodology and assumptions is that it locks in unit capacity factors based on heat input data from Summer 2021; meaning NO_X allocations in state budgets will never exceed the capacity from that key year. The commenter (0409) adds that the EPA then applies dynamic budgeting, which will force capacity factors downward based on future heat inputs – knowing they cannot ever exceed 2021 levels due to the lack of available allowances. The commenter agrees that this is one reason that existing coal-fired generation will be unable to make up the non-SCR EGU shortfall caused by this rule and are unclear how these shortfalls in generation will be covered.

Commenter (0409) argues that the EPA the Proposed Rule, as written, will reduce capacity from key resources (fossil fuel generation) that can respond during extreme weather events; adding that intermittent renewable resources (wind/solar) are weather dependent. The commenter claims that pushing fuel-resilient resources off the grid impacts grid readability and exposes Americans (health and safety) unnecessarily during extreme weather events, due to, for instance, interrupted electricity services and/or outages. As an example, we can chart the role of fossil fuel generation in the context of Winter Storm Uri that knocked out power in Texas, causing devastating effects and deaths. Fuel-resilient resources (coal/nuclear/natural gas) can operate when called-upon, even in adverse conditions. In contrast, intermittent renewable resources (wind/solar) are weather dependent (*i.e.,* electricity is generated only when the wind is blowing, and the sun is shining). Additionally, commenter (0409) recalls that the NERC identifies key regions of the United States that may see a shortfall in capacity and cites concerns voiced by NERC such as grid security (*e.g.*, grid faces possible attacks from Russia, amid heightened geopolitical tensions), solar photovoltaic (PV) tripping (during grid disturbances), supply chain concerns (*e.g.*, shipping delay and labor shortages), and stalled transmission projects. The commenter underscores the point that the implementation of the proposed FIP would come during a time when NERC has already warned of potential reliability risks.

Commenters (0410, 0413) observe that ISO/RTOs are experiencing a trending decline in reserve margin, for which the commenter (0413) worries will accelerate as a result of the proposed rule, during a time when a need for reserves is at its highest due to extreme weather, high load conditions and generator retirements. Commenter (0413) states (along with commenter 0412) that resource adequacy is achieved when the megawatt capacity of the generators in a particular region exceeds the forecasted load for that region by a reserve margin. The commenters allude to replacement of retiring generations but stresses the process is costly and lengthy. Commenter (0412) adds that they have recently detailed in reports the increased strains on the system and the need for fossil generation, as one component, to provide needed back-up services as the number of renewables on our system vastly increases.

Commenter (0414) recognizes that concerns are already arising that electricity supplies (power-generating capacity) are struggling to keep up with growing demands throughout the country, in part, to the rapid transition to clean energy and increased electricity demand due to electrification of the transportation and other sectors. The commenter worries that such shortfalls in electricity supplies could lead to rolling blackouts (referred to as "temporary load shedding") and other emergency measures during heat waves or other peak demand periods occurring this year. The commenter asserts that although the exact impact is unclear, the implementation of the proposed rule could cause additional retirements of dispatchable coal-fired and other thermal generation (*e.g.*, oil- and gas-fired EGUs and nuclear power plants) over the next decade, particularly during the 2026-2028 timeframe.

Likewise, commenter (0414) asserts that the EPA's evaluation (of projected level of shutdowns) is too conservative and should not be limited to the 22,000 MW of dispatchable fossil-fueled generating capacity, which EPA projects will occur by 2030. The commenter alludes that the actual impact to generating capacity could be higher than indicated in the RIA at proposal, because projected levels do not consider impacts from current, upcoming rules to regulate the EGU source category, along with the current industry trends for transitioning to clean energy.

Commenter (0431) expresses specific concerns over NERC's prediction that the probability that Arkansas will experience grid emergencies during a summer heat wave is high; adding a loss of electricity under such conditions would be life-threatening to many at-risk citizens of Arkansas.

Commenters (0499, 0550, 0533) state that more extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability. Commenter (0550) also cites MISO's Reliability Imperative report, which discusses and identifies the complex and urgent challenges to grid reliability in the MISO region. On the whole, the commenters urge EPA to assess whether the revised Group 3 budget trading program restrictions that it has proposed will cause or exacerbate the ozone season electric reliability concerns.

Commenter (0512) states that the strain on their capacity resources has increased dramatically in the past two years. Idaho Power's 2019 Integrated Resource Plan did not show a capacity deficit until the summer of 2028. During the preparation of its 2021 IRP, however, IPC identified deficits in June 2023 and each year through 2026, and summer deficits have subsequently been projected for 2022 [51]. As explained in IPC's 2021 IRP, peak capacity requirements are increasing at a faster rate than forecasted even just a few years earlier, based on factors such as significant customer growth in Idaho, increasingly frequent extreme weather events, droughts, lower ability for demand response and renewable resource programs to meet peak load, and regional transmission constraints. The commenter's record peak load for its system occurred in Summer 2021. The commenter exceeded its previous peak on 12 different days in 2021, with the highest peak registering over nine percent above the previous record peak. The commenter is planning to maximize imports from adjacent utilities but is still facing deficits exceeding 100 MW for the summer of 2022 and 2023. In 2023, the proposed FIP would constrain full-load operations for Units 1 and 2 by 62 percent and 61 percent, and would constrain full load operations for Units 3 and 4 by 20 percent and 24 percent. By 2026, full-load operations would be further reduced by approximately 75 percent for both Units 1 and 2 and 40 percent for Units 3 and 4.

Commenter (0539) underscores the point that electric utilities are responsible for providing customers with safe, reliable and affordable electricity, and expresses their concerns that the proposed FIP, as written, will exacerbate reliability issues on an electric grid that is increasingly unreliable. The commenter warns that many areas of North America already routinely experience grid and transmission stability and reliability challenges, are at elevated or high risk of energy shortfalls for this summer; citing the NERC's 2022 Summertime Reliability Assessment as support. The commenter points out that many of the units subject to potential emissions and/or operational reductions under proposed FIP are located in these capacity-strained RTO regions. The commenter worries that the proposed FIP timeline would result in simultaneous, widespread and extensive changes to some of the country's largest EGUs, occurring over a condense timeframe, presents a substantial risk to the electric grid, and as a result, recommends that the EPA reconsider and extend the proposed FIP's timelines. The commenter references MISO comments, specifically CCR remarks, as well as noting MISO's concerns over shortfalls in capacity, which reduces reliability of the system by increasing the loss of load expectation, for instance, from one day in ten years to one day in 5.6 years. The commenter adds that MISO expects to continue to see shortfalls in capacity; citing Organization of MISO States survey as support. The commenter mentions that the proposed FIP is anticipated to result in accelerated capacity retirement, which will exacerbate the risk of maintaining resource adequacy in MISO – a problem not easily solved with new or replacement generation. The commenter encourages the EPA to conducted dedicated outreach to the Regional Transmission Operators such as FERC/NERC, MISO, the ERCOT, or other RTOs, all of which would be directly affected by impacts to the summertime dispatch ability of units regulated by the proposed FIP.

Commenter (0546) warns that the proposed rule, as written, may incentivize regulated entities to retire units earlier than scheduled, and before the 2026 ozone season. The comment restates the proposed FIP requirements for NO_X emissions budgets (starting with the 2026 ozone season); noting that 131 generating units (with a combined capacity of 58,300 MW) were identified for presumed SCR retrofits. The commenter emphasizes that more than 50 percent of the total capacity is located in just five states in the south-central US: Arkansas, Louisiana, Mississippi, Oklahoma, and Texas. With such a significant concentration of such units in these five states, the commenter worries that there is particular risk of regional reliability issues resulting from implementation of the proposed FIP. The commenter notes that the number of units identified for SCRs and located in MISO South total approximately 11,500 MW of capacity; adding that significant and costly transmission system upgrades would be expected should a number of these generation resources retire early as part of a strategy to comply with the restrictive proposed state emissions budgeting approach for the 2026 ozone season. The commenter explains that the time required to obtain all necessary external project approvals, complete material procurement, and to construct such upgrades make complying with the 2026 deadline infeasible. The commenter briefly describes a typical installation schedule; noting that external project approvals take up to 18 months, and transformer procurement requires up to two years, and new and rebuilt transmission lines within the area may take five to seven years to design and construct, partly due to the terrain and permitting requirements. The commenter concludes that the EPA's proposed 2026 NO_X budgeting approach simply does not allow for adequate time to execute transmission system upgrades which may be necessary to accommodate the accelerated unit retirements that would almost certainly occur should the EPA finalize its proposal without changes to provide additional flexibility to the program.

Commenter (0554) states that the retirement of a single 400 MW coal unit triggers the need for wind, solar, battery, dispatchable capacity, and transmission investments that require time for permitting, regulatory review, equipment procurement, and construction that is out of sync with the compliance timelines in the Proposed Rule.

Commenter (0554) maintains that replacement resources must be adequately designed, tested and verified to ensure that the transmission system can accommodate variable resources. The commenter anticipates investing tens of billions of dollars towards energy transition for coal-fueled resources. The commenter notes that the generation and other services of a single 400 MW unit is costly (billions of dollars to replace), and expresses concern that should, multiple coal units be forced to retire under the Proposed Rule, the resource replacement and transmission upgrades needed to replace the electricity generated by the unit will add to costs – tens of billions of dollars – and require lead times of no less than ten years. The commenter further worries that as wind, solar, and energy storage become a larger portion of utility provider's portfolio effective capacity contribution values will decline.

Commenter (0557) identifies key regions of the United States that may see a capacity shortfall and cited concerns such as grid security, solar PV tripping, supply chain concerns, and transmission projects. The commenter encourages the EPA work with the energy sector to build realistic time frames into the Rule; arguing that manufacturers are reliant on consistent, affordable electricity and the grid as it stands cannot sustain massive capacity reductions in such a condensed period of time.

Commenters (0395, 0550) recommend that the EPA consider accepting a reliability impact analysis conducted by the appropriate experts (FERC, NERC, RTO, and ERCOT) to assess more accurately grid reliability by evaluating the impacts from the proposed rule for all areas, as well as provide sufficient time for actionable feedback. The commenter (0550) expresses concern over Texas's vulnerability to sudden power shortages when power plants in the state unexpectedly close because each power plant provides a larger fraction of the grid's total power than individual power plants in either the Western or Eastern Interconnections. The commenter highlights the fact that the current market structure is not providing adequate incentive for new or expanded generation to meet the current and future generation demand in states, like Texas. According to the commenter, they are actively engaged in attempting to retain and expand as much dispatchable generation as possible to address reliability concerns, and strongly believe that the EPA's proposal will exacerbate pressures on plants that are already vulnerable to closure without providing sufficient time for the development of other environmentally sustainable solutions to mature.

Commenter (0412) states, in terms of reliability, fuel assurance means the availability and performance of a generation resource when needed by system operators. The commenter states that for thermal generation, it considers the probability that a resource will be on a forced (unanticipated) outage when needed, due to equipment failures, inability to secure fuel, or other reasons. The commenter supports the use of or incorporation of intermittent resources (wind and solar); however, the acknowledges the limitations of these resource (impacted by weather conditions), noting that the availability of intermittent resources is often based on their expected ability to perform when needed during peak periods of demand.

According to the commenter (0519), increases in clean energy demand is driving rapid-pace retirements of large, dispatchable, "24-7" fossil plants, with replacement capacity provided and distributed by weather-dependent, non-dispatchable, intermittent sources (wind and solar). The commenter stresses that stable electricity generation by remaining power plants is increasingly important to sustain the rapid build-out of renewables. The commenter worries that these power plants are being phased out faster than they can be replaced by other dispatchable energy sources, sufficient battery storage. The commenter cites the study, "Resource Adequacy in the Desert Southwest;" adding that the study found:

- As the penetration of variable resources grows and traditional generation retires, the periods in which the system is most vulnerable to reliability risks shift away from the traditional peak and toward periods of lower renewable production; this effect is exemplified by the shift in reliability risk to the evening net peak that occurs as solar penetration increases.
- As the penetration of energy-limited resources grows, the risk of loss of load events will spread across an increasing number of hours; as the number of hours in which the system is at risk increases, the value of energy-limited resources with finite durations diminishes.
- Variable and energy-limited resources exhibit complex interactive effects, meaning that the combined value of a portfolio of resources may differ from the sum of its individual parts."

Commenters (0289, 0355, 0359, 0373), at large, claim that the projected costs in the RIA appear flawed. It does not evaluate remaining useful life of the sources on which the rule imposes costs and must be updated and presented in state-specific and unit/facility-specific amounts. The commenters states that retrofit costs are significant, and many of the units identified by the EPA (subject to the rule) are slated for retirement within a few years after the 2026 implementation date, and long before the assumed 15-year period; essentially making those retrofit investments uneconomic and imprudent. Commenter (0289) adds that the RIA also fails to consider or evaluate the cost of transmission upgrades and replacement electricity generation that will be needed to meet electricity demand as a result of the lost capacity that will result from the rule. The commenter observes (at least in the MISO region) that the energy transition to more and more renewables with fewer and fewer baseload plants is advancing more quickly than upgrades to the electricity grid are able to accommodate. Similarly, commenter (0355) claims that the EPA has provided no basis for the assumption that the identified at-risk generating units can be retrofitted by 2026 or that it would be economical to do so. Commenter (0359) argues that the high number of projected retirements is directly related to the exceptionally high-cost threshold used in this rulemaking for EGU controls in 2026 – $11,000 per ton to retrofit or install new SCR control technology. According to the commenter, this threshold is unprecedented in past CSAPR rules, except for using $9,600/ton to represent the more stringent analysis in the RIA for the recently promulgated Revised CSAPR Update rule and to represent the more stringent analysis of $10,000/ton in the 2011 CSAPR final rule. Commenter (0373) asserts that the EPA has provided no analysis of the reliability impacts of retiring large amounts of coal-fired generating capacity within such a short period of time, nor did the Agency consider the impacts of retired units on inflationary pressures by reducing the flexibility to switch fuels when natural gas prices rise for power generation and other uses. The commenter opposes the proposed rule based on costs, detrimental impacts on the coal fleet and its potential threat to the reliability of the electricity grid.

Commenter (0289) worries that with more baseload retirements (as a result of the proposed rule), grid reliability particularly in the MISO region, will only get worse. The commenter recommends that the Agency to analyze the impact of baseload retirements on society and the economy (at large), including the increased risk of blackouts and brownouts in electricity regions and what cost those types of events may impose. Additionally, the commenter states that over the next nine years (2022-2030), announced coal retirements total slightly more than 86,000 MW, the bulk of which (more than 51,000 MW) are located within the footprints of PJM and MISO (spans all or parts of 26 states). According to the commenter, coal fleet in the two regions (PJM and MISO) are expected to decline by half by the year 2030; without considering impacts from the proposed rule, which is expected to result in more coal retirements. The commenter reminds that the proposed FIP is expected to result in 23,000 MW of coal retirements by 2030. The commenter highlights that replacing these EPA-caused coal retirements would require the construction by 2025 of 133,000 MW of wind power or 46,000 MW of solar power (based on MISO’s accredited capacity values).

Commenter (0333) briefly discusses obligations under reliability-must-run (RMR) contracts, which according to the commenter, provide a theoretical short-term—and expensive—fix to the operational reliability concerns that retirements, as result of the proposed rule, would create. The commenter recognizes that RMR contracts could conceivably include payments to fund the installation of SCRs, but these are short-run solutions, because by law, RMR contracts can only address violations identified within the two-year horizon of ERCOT's analysis, in this case, and the value of any capital improvements (such as SCRs) that would have been paid for by ERCOT would have to be paid back to the market as a condition for the generator's continued participation in the market beyond the term of the potential RMR contract. The commenter adds that during the time between when the RMR contract ends and the in-service date of the new transmission, the grid would still be subject to the reliability concerns. The commenter expresses concern that the ability to use RMR may be limited if the EGUs called upon do not have sufficient NO_X allowances to operate; adding PUCT Rule section 25.503(f)(2)(C) exempts generators from complying with ERCOT instructions that would violate environmental laws. The commenter illustrates the possible real-world effects of this rule by describing the generation events/challenges faced during the summer of 2019, as support.

Commenter (0354) believes that, if adopted as proposed, the proposed FIP will result in early retirements of many of the fossil fueled EGUs that provide dispatchable electricity generation in Texas; jeopardizing the continued availability of reliable electricity in the state. The commenter mentions that the demand for reliable electricity in the state of Texas is growing at a pace that exceeds the rest of the country and underscore the point that the state's ability to provide reliable electricity to meet that demand is being strained by increasing penetration of renewable electricity generation that must be balanced with dispatchable electricity generation. The commenter states that RTOs must have enough dispatchable electricity generation capacity to meet the state's growing demand to ensure that safe, reliable electricity is available at all times, including times of peak demand for electricity (hot summer and cold winter days) and when electricity from renewable resources wanes due to reduced electricity generation potential. The commenter asserts that there is not enough financial incentive currently available to attract adequate dispatchable electricity generation to meet the state's future electricity demand. The commenter states that it is absolutely critical that the proposed FIP does not lead to the premature shutdown of existing EGUs that provide the dispatchable electricity generation needed to support stable operation of the state's electricity grid required to provide reliable electricity. The commenter observes that the proposed FIP provides no indication that the EPA sought or considered input from the appropriate RTOs (ERCOT, SPP, and MISO) regarding either the potential impacts that retirements of units (or other aspects of the proposed FIP) would have on the continued availability of reliable electricity in Texas or possible solutions to mitigate or prevent the loss of reliable electricity that will result from the proposed FIP.

Commenter (0355) states their belief that the proposed rule result in the premature retirement of generation facilities that are currently relied upon, and that will be relied upon in the future to keep the lights on during critical periods of the year (and replacing them with less dependable wind and solar power); thus, adversely impacting the reliability of generation and transmission of electricity. The commenter mentions that, in the case of the MISO South region, much of their available capacity is expected to be lost due to the FIP (by 2026 and beyond). The commenter worries that absent significant investments in new capacity or retrofits, there will not be sufficient capacity to serve load in MISO South; adding that 2/3 of the of the country face the prospect of temporary blackouts this summer when electricity demand intensifies.

The commenter (0372) argues to the extent the FIP results in (early/premature) retirements that have not yet been announced, the FIP will cause additional reliability concerns that have not been taken into account.

Commenter (0395) predicts that due to cost of controls and the uncertainty of the market, it is anticipated that a significant number of units would retire early instead of attempting to meet the aggressive emissions rates EPA identifies. The commenter acknowledges that the EPA projects unit retirements in the amount of 22,000 MW in the affected states, including 9,000 MW in Texas. The commenter adds that the Agency also admits that an additional 81,190 MW will not retrofit controls and will not be available to the national grid during the ozone season. The commenter concludes, as this represents a significant fraction of the dispatchable capacity available in these regions, this Proposal, as written, threatens the stability and reliability of the nation's electric grid.

Commenters (0400, 0557) express their concern forced early retirements of EGU units will reduce capacity factors for a substantial amount of generation subject to the FIP. The commenters explain that the forced retirements will involve 48.5 gigawatts of capacity from 79 EGUs within a short window of time, at a time when there are already grid reliability concerns. According to commenter (0557) the proposed FIP will (1) cause stranded assets due to SCR control installation timelines for EGUs that cannot be met with existing contractual resources, aside from costs; and (2) require new power generation, because existing generation will be capped by limited NO_X allocations.

Commenters (0408, 0499, 0533) worry that the EPA's proposed revisions significantly restrict the NO_X ozone season Group 3 trading program, which could cause units to retire earlier than anticipated and/or limit their operations, including during periods when most needed for grid reliability. More specifically, the commenters state that the EPA's proposal to impose significantly reduced state budgets in 2026 along with the daily backstop emissions rate, beginning in the 2027 ozone season, on large coal-fired units currently without SCRs, without regard to whether such units will actually install SCRs, could result in additional unplanned retirements by 2026 – many of which are units clustered in the same regions, which may impact grid reliability.

Commenter (0409) fears that the proposed rule will effectively force many cooperatively owned coal-fired units, and other units of which cooperatives must rely on for significant power, to shut down; disproportionately harming electric cooperatives (coal-fired) and their consumer-members. The commenter presents background on the development of the 1978 Fuel Use Act [42 U.S.C § 8301 et seq]; noting that about two-thirds of today's cooperative coal-fired generation were built under the Act's "coal capable" mandate. The commenter maintains that coal-fired electric generation remains the dominant source of electric generation for cooperatives.

Commenter (0413) sees a shift in ISO/RTOs respective generation portfolios; noting that thermal generators continue to provide essential reliability services. The commenter is concerned that the proposed rule could cause generator retirements due to the limitations on operations and/or the cost of installing SCR by 2026; however, they stress that the level of retirement will depend on the level of flexibility offered in the rule.

Commenters (0499, 0528) remind EPA that in other actions – proposed determinations regarding CCR demonstrations in which EPA proposes to allow facilities to continue using their CCR impoundments “to the extent necessary to address demonstrated grid reliability issues,” subject to certain requirements and coordination with the respective RTO – the EPA has recognized the importance of reliability and specifically crafted provisions that would account for reliability concerns, but note that those steps were not done here. The commenters, in general, urge the EPA to address the reliability concerns related to retirements resulting from the final FIP in a similar manner and to engage with RTOs to better understand and account for such reliability issues. The commenters (in addition to commenter 0533) also urge the EPA to keep the docket open for additional comment specifically regarding grid reliability concerns; adding that additional time would allow RTOs the time needed to engage in a more robust assessment of potential reliability concerns and engage with EPA on these issues.

Commenter (0528) worries that the installation of controls and monitoring equipment (to meet EPA’s proposed schedule) will result in the early retirement of units, placing stress on the grid. The commenter maintains that a control option is not cost-effective if it causes multiple EGUs to retire early and results in grid failures. The commenter asserts that such efforts are an example of overcontrol because more NO_X may be reduced – via early retirements – than is justified. The commenter cites the Sargent & Lundy NO_X Controls Memorandum, noting that the report found that in the case of Texas, nearly five million MWh of coal-fired generation is anticipated to go offline in the next several years from planned retirements; adding that an additional 27 million MWh of coal-fired and oil- and gas-fired generation may go offline in Texas, according to the report. The commenter highlights that in past actions EPA has recognized the impact of CSAPR requirements on grid reliability; however, it was not considered for this rulemaking action.

Commenter (0912L) believes that the proposed FIP, as written, would essentially render moot the hundreds of millions of dollars ratepayers have already invested in enhanced NO_X controls, including enhanced combustion controls and SNCR systems, and imposes a draconian edict that all plants install replacements to those systems called Selective Catalytic Reduction (SCR) controls in just three years from the start of the new program is unrealistic and impractical. The commenter contends that even if regulated entities would be able to absorb SCR costs, it is not possible to accomplish such monumental task of universal SCR installation by 2026, due to permitting, current market conditions/prices and supply chain issues. The commenter believes that electric utilities will not have time or funds to install these expensive controls, nor will there be sufficient time to stage and stagger the planned outages necessary for such a massive construction project across the fleet. According to the commenter (along with commenter 0327), the most realistic outcome of EPA's action will be the mass premature retirement of coal and gas units not currently equipped with SCRs – the premature closure of 35,806 MW of essential dispatchable generation in the next four years (37 percent of the coal generation by SPP will be gone by 2030). The commenters encourage the EPA to slow the rulemaking process down and collaborate with appropriate organizations and agencies to ensure the reliability and resilience of the electric grid is not compromised.

Commenter (0286) notices an increasing trend of near-emergency and emergency conditions in its territory – *i.e.*, the number of "Max Gen" declarations (Emergency, Alert, Warning and/or Event) that have impacted the region have seen an increasing trend from 2018 (5 declarations) to 2021 (8 declarations). The commenter is concerned that USEPA's proposal will further exacerbate this dangerous situation with the reliance on power shifting and plant idling during this time of transformation of the United States power grid to a reliance on renewable energy.

Commenter (0332) provides a brief background on the makeup of the US electricity grid (40 percent of America's electricity came from clean carbon-free resources in 2021) and talks about existing improvements made and future improvements – *e.g.*, reaching a carbon reduction goal of net-zero by 2050, in an effort to diversify their generation portfolio. The commenter states that energy storage is a key asset in helping the grid integrate increasing amounts of renewables and offering resilience and reliability, and currently electric companies are the largest users and operators of operational storage in the country—representing 96 percent of active energy storage projects. The commenter adds that over the period of 2015 to 2020, there was a 544 percent increase in advanced energy storage devices. The commenter implies that renewable energy deployments are expected to continue – *e.g.*, EIA projects that in the United States the share of renewables in the electricity generation mix will more than double by 2050, resulting in a decrease in primary greenhouse gas emissions associated with electricity production, in addition to other air pollutants (NO_X, SO_2, etc.). The commenter adds that developing a broad range of advanced clean energy technologies can help further expedite the transition of the electric power sector to one that is low- or non-emitting while keeping electricity affordable and reliable for customers.

Commenter (0333) notes that they, along with ERCOT are swiftly developing rules regarding technical products and operational changes to maintain grid reliability in a fleet where there is already high variability due to the proliferation of intermittent generation sources – *e.g.*, development and implementation of the ERCOT Contingency Reserve Service (ECRS) for implementation in 2023 – an ancillary service designed to recover system frequency to 60 Hz following balancing events which typically occur because of forecast uncertainties and longer-lasting net load ramping events that result from reduced output by variable generation sources. The commenter reiterates that the need for ancillary services increases with the addition of renewables on the grid.

Commenters (0355, 0409, 0411, 0532) expresses their support, in general, of prudent integration of renewable power into the grid; however, the commenters insist that it must be done at a pace that does not exceed the technological or physical limits of power supply (*i.e.*, when reasonable and economically justifiable). The commenters assert that dependence on fossil fuel power generation in the foreseeable future is inevitable, and while the electric sector is poised to play a significant role in transforming and reducing emissions in other sectors of the economy through increased electrification, actions that threaten grid reliability (premature baseload coal plant retirements, without adequate time to replace loss generation) or increases in the cost of electricity will negatively impact these efforts and further strain electric system reliability. As an example, the commenter (0355) notes that a sudden drop in wind production during a 2019 heat wave (which at the time made up 20 percent of the generation in Texas) caused ERCOT to initiate emergency procedures to avoid blackouts and adds that MISO experienced similar events in the winter of 2019. The commenter further highlights that the coal fleet demonstrated its resilience during the 2021 Winter Storm Uri – almost doubling its output (+92 percent) compared to the previous year and by producing almost half (49 percent) of MISO's electricity during the four-day period; and stresses the point that the power outages would have been even more severe, and it is possible that many more people could have died, if the coal-fuel generation units were unavailable. The commenter recalls similar experiences in the SPP region, during that time. The commenter concludes, based on their experience and known limitations of available resources, that the soundest energy strategy is one that includes a mix of resources, including fossil fuel units.

Commenter (0372) expresses concern over the impact of severe weather events (ice storms) and high-demand times (winter and summer months) on the local system and overall grid readability. The commenter provides one example (*e.g.,* February 2021 ice storm) where the interruption of severs were avoided (due to a near simultaneous restoration of a key transmission facility and the return to service of Cooper Station generation). Had the interruption occurred, the commenter claims that residents would have been heavily impacted by a loss of electricity that powers heat appliances, furnaces and life-saving medical necessities.

Commenter (0375) claims that their states of Arkansas, is also paying the cost for and examining the causes of forced power outages that have occurred because of extreme winter weather events. The commenter recognizes that alarm bells are being rung by electric system experts, that the replacement of fossil-fuel generation with intermittent renewable energy sources is not always reliable and available. The commenter concludes that using unacceptable costs to force retirement of units needed to maintain reliability is a reckless strategy that we cannot afford.

Commenter (0395) disagrees with EPA’s prediction that new generation will come on the market to replace the capacity removed from the market by this Proposal; adding that new projected generation is likely to include more ‘unreliable’ renewable resources (solar and wind) – *i.e.,* amounting to 84 percent of new capacity in 2025 and 76 percent in 2028. The commenter states that, in the case of Texas, the state has been able to manage the volatility in natural gas prices due to its diversified generation fleet. The commenter underscores the point that over-reliance on renewable resources (solar and wind) can quickly create crisis grid scenarios, including rolling blackouts, because dispatchable resources are necessary to balance load as renewable generation fluctuates, because these resources are impacted by changes in weather conditions and, as such, their contribution to the grid fluctuates and cannot be relied upon at all times. The commenter admits that if/when, 625 MW of coal generation are forced to sit out the peak summer season in Texas in 2026 (as per EPA's own modeling), they will most likely shut down entirely; increasing the demand for natural gas and creating more volatility and significantly higher retail prices for electric consumers.

Commenter (0400) suggests that coal retirements in particular pose a significant challenge to grid reliability largely because of its importance to our nation’s security, state economy (industry offers high wages and employs over 300,000 people either directly or indirectly), and energy sector – accounts for 22 percent of the nation’s energy. The commenter discusses the abundancy of coal in the US (more than 250 years-worth remaining); as a result, coal is able to be used as an energy source to provide affordable electricity to households, businesses, manufacturing facilities, etc. The commenter stresses that coal is expected to remain a constant reliable fuel source.

Commenter (0411) states that a challenge to bringing renewable energy on-line is incorporating them into the current electrical grid system via a transmission interconnect. The commenter explains that existing interconnects are currently being used to feather fossil generation offline, and transition to renewable generation, maintaining, or re-using the interconnection point. The commenter claims that their interconnect queues are so constrained it has resulted in a bottleneck for transmission interconnections causing delays in a time frame of many years; making it difficult to meet the planned schedule to introduce renewable sources to the grid. The commenter fears that the proposed FIP will force the retirement of units prior to existing resource plan schedules for renewable transition and before the appropriate and necessary systems are in place to ensure adequate grid reliability; as a result, the commenter expects to see increases in costs and adverse reliability impacts.

Commenter (0434) briefly describes efforts made over the years to diversify their portfolio and invest in more renewable energy sources, specifically wind and solar generation, which have been deemed to have the greatest rates of return. More specifically, the commenter (along with commenter 0333) notes that the incorporation of renewable energy sources in ERCOT's energy portfolio has grown from less than1 percent of the total generation capacity (2007) to roughly 38 percent, and currently produces an estimate 37 percent of the energy in the region. The commenter adds that they expect that these intermediate sources will contribute or account for approximately 33,500 MW in generation capacity over the next three years; adding that gas-fired generating units are expected to account for only 4 percent, and zero coal units. While the commenter acknowledges the benefits of incorporating renewable energy sources energy portfolios, they agree that these intermediate sources pose problems – *e.g.*, unreliable and usage often impacted by weather conditions, and the more that power systems rely on these and other inverter-based generators, the greater the risk that a major grid disturbance will cause the grid to cascade into a catastrophic blackout condition. In an effort to provide examples of problems often associated with solar integrations, the commenter references multiple NERC reports that assess major grid disturbances to solar units, including five events in California and one last year in Texas.

Commenter (0414) acknowledges current efforts by industry to transition to clean energy and the decarbonization of the electric power grid; adding that transition is not just reducing CO_2 emissions from the electric power sector but also achieving substantial additional reductions in emissions of other conventional and hazardous air pollutants, including NO_X emissions that can contribute to the formation of ozone.

Commenters (0499, 0533) maintain that the EPA's assumptions about new sources of electricity that would replace the current fossil fuel-fired generation fleet must be verified with grid operators who have knowledge of future generation, are inherently flawed. The commenters worry that the supply of renewable generation may not be adequate to replace early retired EGUs; underscoring the point that due to an ongoing U.S. Department of Commerce investigation into solar panels, many currently-planned solar projects, for example, are delayed and may not be operational in time to meet the proposed 2026 deadline, and without sufficient generation to replace retiring fossil fuel-fired generation, there are likely to be significant reliability issues. The commenters highlight that the proposed FIP provides no avenue for grid operators to identify potential generation needs that may otherwise require the operation of units planned for retirement to solve a transmission or reliability constraint. The commenters briefly discuss the importance and role of essential elements (oil and natural gas) play in the transition to renewable sources and suggests that the proposed restriction to the Group NO_X trading program likely will make it more difficult for such units to provide needed stability to the grid. For instance, the commenters state that EGUs that operate at low loads during the ozone season to stabilize the grid may not be able to do so because they may not be able to achieve the daily backstop emissions rate during their limited operation. The commenters further add that during periods of high temperatures, more fossil fuel-fired EGUs are called on to operate to provide necessary electricity and grid reliability to meet peak demand, and it is during these periods, when coupled with overly restrictive regulations and such issues as high allowance prices, that EGUs' operation may be uneconomic. The commenters encourage the EPA to collaborate with appropriate organizations and agencies to consider the impacts of environmental regulations, which together can be far more impactful than when looked at separately or piecemeal. Additionally, the commenters mention that there are studies currently underway to evaluate and identify reliability issues and solutions (associated with electricity generated by solar and wind), so that they can be integrated into the planning of transmission and distribution projects. The commenters urge the EPA to consider these studies' findings in the modeling approach to obtain a more accurate picture of transmission capabilities that are necessary to help meet regional electricity demand.

Commenter (0519) believes that increasing retirements of stable, readily-dispatchable electricity generation facilities further aggravate existing supply challenges. The commenter references NERC's Summer Preparedness report, noting that the report found escalating concern regarding resource adequacy, highlighting the loss of large amounts of conventional resources as part of the clean energy transition and replacement by (inherently unreliable and energy-dilute) intermittent wind and solar. The commenter claims that the loss of these conventional resources coincides with high demand periods in the summer (which also covers ozone season), amplifying the impacts of these resource adequacy issues. The commenter supports the incorporation of renewables in electricity portfolios; however, even with over 20GW of renewables in use today, the summer period is highly reliant on conventional resources.

Commenter (0554) states that sufficient electric generation is a key component to a reliable electrical system, and one of the main responsibilities of a regulated utility is to maintain the stability of the electric grid by instantly delivering generation in response to demand as well as ensuring there are sufficient resources held in reserve to cover potential compromises in generation or transmission capabilities. The commenter notes that fossil-fuel generation has historically provided a low-cost, reliable, steady stream of energy while operating at high capacities, and although the commenter acknowledges changes in energy generation (to include more renewable fuels) they emphasize that coal units provide significant contributions to generation capacity and grid stability, particularly during periods of low wind or lack of solar generation. The commenter briefly compares capacity amounts between non-renewables to those EGUs subject to the proposed rule; noting that coal-fueled units affected by the SCR requirement in the Proposed Rule can generate 400 MW or more of electricity at any moment in time, while non-reviewable sources (wind and solar) required about 2.25 times the amount of capacity is needed to replace energy generated from each megawatt of coal capacity (or roughly 445 MW of wind and 445 MW of solar). The commenter adds that the capacity amount would still be insufficient to replace the 400 MW of coal lost, as it does not provide ramping capabilities needed to respond to intra-day and intra-hr changes in load. The commenter mentions that each of these generating assets require incremental transmission upgrades to accommodate interconnection, and additional upgrades are often required to facilitate the flow of power on the transmission system, which can be significant in both cost and time schedule.

Commenter (0547) argues that replacing higher emitting fossil-fuel-fired plants with lower emitting sources during the height of summer is impossible without impacts to the reliability of the energy supply, partly because there is very limited ability to transfer energy across regional grids or rapidly integrate renewable energy sources into the grids. The commenter further contends that the EPA's assumption that generation shifting is a reasonable emissions reduction control because "all EGUs that would be regulated by this proposed rule participate in highly coordinated, interconnected systems where generation shifting will inevitably occur in response to pollution control requirements" is flawed. According to the commenter the proposed FIP ignores two critical aspects of the nation's energy supply and transmission grid (1) there is limited capacity to transfer energy across the three separate energy grids and the nation's energy grids cannot rapidly integrate the new renewable energy sources onto the grid without massive and costly overhauls; and (2) Renewable energy sources are unreliable and produce significantly less MWs of energy; therefore, energy producers must continue to rely on fossil-fuel-fired baseload generation to meet our country's growing energy demands. The commenter provides a brief overview of the electricity systems as it currently stands, compartmentalized into three separate regional sections: Eastern, Western, and Texas Interconnections. The commenter briefly describes how their system straddles the Eastern and Western grids and serves separate markets. The commenter explains that these two grids operate with different electrical characteristics that prevent electricity on one side of the national grid from being delivered directly to the other. More specifically, the commenter notes that for power to be transferred between the east and west systems, alternating current ("AC") electricity must be converted into direct current electricity to cross the seam and then must be converted back to AC. The commenter adds that there are only limited amounts of physical transfer capacity between the interconnections, manage electric generating and transmission resources on both sides of the Eastern and Western Interconnections' seam to serve their member-load requirements. The commenter notes that over the years, differences have developed in the generation mix on either side of the seam – coal primarily on the west, where coal resources can be cheaply and dependably obtained, and coal, natural gas, and wind largely on the east, where more potential for extensive wind resources exists. As an example, the commenter briefly describes the difficulties with transferring energy across the seam at the Laramie River Station, near Wheatland, Wyoming; noting how, in this case, the plant cannot provide generation from Units 2 and 3 to customers on the east side (to Unit 1, which is electrically connected to the eastern system) unless it utilizes certain DC ties along the seam. The commenter contends that if they were forced to shutter the Laramie River Station Unit 3 during the summer months, the loss of 627 MW of power on the western system could not be easily replaced by wind energy generated on the eastern system—the loss of 627 MW of power exceeds the total capacity of transfer rights that the commenter has said to have secured across the nearby DC ties. The commenter concludes that without broad changes in both the physical constraints between the Eastern and Western Interconnections, utilities that straddle the divide cannot plan to meet member load requirements under a regulatory structure that presumes that it can simply redispatch renewable generation on one side of the grid to replace lost thermal power on the other.

Commenters (0361, 0396, 0411) maintain that the EPA should consider the potential impacts to the reliability of the bulk electric system if the requirements in the Proposed Rule are implemented. Commenter (0361) suggests that the proposed rule's reliance on generation shifting raises concerns, in an electric industry governed by state commissions, Regional Transmission Organizations (RTOs), and a large, interconnected bulk power system. The commenter further asserts that the flow of energy is a function of the operation of the grid and the relevant RTO and adding another layer of complexity (state emissions budgets) by which facilities would idle, cease to operate, or retire as a result of this Proposed rule would not only carry a disproportionate cost—it could significantly undermine the reliability of the bulk power system. Commenter (0396) warns that the possibility of mass retirements comes at a time when the bulk power system cannot afford it - especially as the bulk power system transitions to renewable resources. The commenter mentions that these challenges have been chronicled by numerous reports – *e.g.*, National Association of Regulatory Utility Commissioners' (NARUC) 2021 white paper, entitled "Resource Adequacy for State Regulators".

Commenter (0412) describes in detail mechanisms (capacity market, energy market and other emergency measures, including must-run generation) used to ensure the reliable operation of the bulk electric system. First, the commenter discusses its Reliability Pricing Model – long-term reliability and resource adequacy through capacity market – that requires each electricity provider to acquire enough power supply resources to meet demand (of its customers) not only for today and tomorrow, but for the future (three years out), which are secure through the capacity market. By matching generation with future demand, according to the commenter, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies, which in turns provides customers with reliable power and stable rates, while also attracting new investments and encouraging ongoing incorporation/transition to new fuel sources. The commenter also notes that load forecasting is a major input to the capacity market and an important part of maintaining the reliability of the bulk electric system, because, according to the commenter, helps make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. The commenter mentions that these forecasts can be used to make informed decisions when participating (or investing) in energy markets in the near- or long-term (occurs annually, provides a 15-year load projection). The commenter provides an overview of electricity generation, noting that electricity sent out onto the bulk electric power grid must first match customer demand. The commenter adds that the grid is monitored non-stop (24 hours a day and 7 days a week) by dispatchers, who see system conditions and predict what electricity will be needed on the grid over the next two hours. Specifically, the comment states that a secure electronic signal is sent to market operations center, which then transmit the signal to generating plants, telling them how many megawatts of electricity to generate. The commenter suggests that even with planning and coordination there are times when the current generation does not meet demand, during which dispatchers must approve and release energy reserves to fill in the gaps. The commenter states that the generation scheduling process begins a day ahead of when a generator is needed to run (called Day-Ahead Market, a marketplace where prices are set for energy that will be delivered in the future); adding that hourly prices are calculated based on generator offers, bids from entities that need electricity, scheduled energy trades, and market-related financial transactions. The commenter briefly remarks on the biding/pricing process (*e.g.*, load-serving entities bid in the amount of energy they would like to purchase, generators submit offers of how much they are willing to supply and at what cost). The commenter describes the differences between Real-time Market and Day-Ahead Market, noting that Real-time Market is a spot market, meaning electricity is procured for immediate delivery. The commenter adds that electricity prices are calculated at five-minute intervals for more than 1,000 different pricing points based on actual grid operating conditions and are published on the commenter's official, formal website. Energy suppliers, as stated by the commenter, are paid the day-ahead price for their scheduled output and the real-time price for any energy that exceeds the scheduled amount. The commenter declares that if a non-retiring generation resource participating in the energy market must be run to maintain the reliability of the bulk electric system, the commenter may schedule and dispatch that resource (*e.g.*, out of economic merit) to address that reliability risk. The commenter adds that must run generator offers are subject to price caps that rely on cost-based offers submitted by the generator (*e.g.*, costs of emissions allowances). The commenter acknowledges that they have no authority to order generating plants (generators that provide notification that they intend to deactivate or retire) to continue to operate; rather, the commenter suggests that they have the responsibility is to evaluate, through a deactivation analysis, the reliability impacts caused by the proposed deactivation and identify transmission solutions to ensure ongoing reliable transmission operations. The commenter says that they request the generating unit to continue to operate beyond its desired deactivation date. If the generation owner agrees to continue to operate, the generation owner may file a proposed rate with FERC seeking full cost recovery associated with operating the unit until it may be deactivated. Additionally, the commenter states that they have emergency operations plan to set forth to address various emergency and other unanticipated scenarios – a manual which describes the steps to take to mitigate an operating emergency pursuant to NERC Reliability Standard EOP-011-1 (Emergency Operations). The commenter explains that they use four levels of emergency-related activities starting with advisory activities and progressing through alerts (issued one or more days in advance), warnings (issued in-real time ahead of the event), and actions (issued in real-time, response required). The commenter agrees that there has been a shift in its respective generation portfolio through the addition of renewable generation and inverter-based resources; however, stress the importance of thermal generators that continue to provide essential reliability attributes and services. According to the commenter, thermal generators supply the bulk of the essential reliability attributes needed to support the grid, which include inertia, frequency response, reactive capability, fuel assurance, and black start.

Commenter (0413) recognizes, pursuant to legislative and regulatory directives, the ISO/RTOs responsible with ensuring the reliability of the bulk electric system in their respective footprints. In performing these functions, the commenter observed that ISO/RTOs must comply with federally-approved reliability standards promulgated by the NERC and the applicable Regional Entity.

Commenter (0400) asserts that the EPA has not coordinated with appropriate parties (FERC, NERC, RTOs, or States) regarding energy reliability impacts of this rule. Commenter (0400) (along with commenter 0550) asserts that the EPA has no expertise on grid reliability and suggests that the Agency surpassed its authority granted to them by the Congress under the CAA and oversaw the regulation of utilities is traditionally associated with the police power of the States – without any meaningful evaluation of grid reliability concerns.

Commenter (0520) states their belief that the Proposed Rule will likely cause early coal-unit retirements that will undermine the reliability of the bulk electric system and adversely impact affected coal communities as well as customers and electricity consumers in the West.

Commenter (0554) states their belief that the propose FIP undermines the reliability of the bulk electric system in the West; thus, jeopardizes energy supply and reliability. The commenter contends that it is not possible for a regulated entity to either install SCR on multiple units or retire and replace the energy generated and vital ancillary services provided by these units by 2026. The commenter underscores the point that extending the timeline to install SCR by a few years alone is not enough to resolve the cascading effects to system reliability. The commenter recommends that the EPA allow states to work with all affected stakeholders to implement the CAA's good neighbor provision and achieve a clean energy transition in a manner that balances community interests, reliability, costs, and environmental impacts. The commenter maintains that cost and timing considerations are likely to make SCR a non-viable compliance alternative for many units in the West, because installations of SCR on a coal or gas-fired power plant is a significant and requires long-term investment that, despite the cost-effectiveness calculations developed by the EPA to support the Proposed Rule, will simply not make economic sense for customers, because, over time, customers will benefit more from investments in low-cost renewable resources, storage, and non-emitting dispatchable resources (nuclear, fuel turbines).

Commenters (0333, 0434) state that changes in the location of generation sources can require the construction of new transmission facilities to deliver power from generating resources to customer loads. The commenters briefly discuss the findings of a shorten or limited assessment performed (by the commenter) to determine the transmission needs that would potentially arise in 2026 with the expected retirement of 10,800 MW of thermal generation, due to the proposed FIP. The commenter notes that the study identified a need for several new 345 kV and 138 kV lines and transformers to mitigate reliability issues as a result of the retirements, at a cost of $1.2 to $1.5 billion and take roughly five years or more to complete. The commenters stress that these costs would be borne entirely, in this case, by Texas consumers. The commenters expect (based on other studies they have conducted) that, in their case, retirements alone would accelerate the need for an additional 345 kV import path into the Houston area to address thermal and voltage issues and several 345 kV upgrades in and around the San Antonio area; costing roughly $2.7 to $5.2 billion and take five years or more to complete. The commenters worry that billions more might be needed to build a new import path from West Texas to serve the major metropolitan load centers in Texas, particularly if new generation is built with a focus on using more renewable sources (wind and solar). Given that transition facilities take at least five years to build, the commenters worry that impacts from premature/early retirements may remain unresolves for an extended duration. According to the commenters, a generation owner must provide at least 150 days' notice of an intention to suspend operation of a generation resource [16 Tex. Admin. Code § 25.502]; adding that generation retirement decisions are typically made with only the minimum required notification before the SCRs would need to be installed. The commenters acknowledge that this delayed notice means possible exposure to the operational consequences of the retirements until the time that the transmission improvements could be implemented – *e.g.,* the following thermal overloads (due to retirements):

- Eight 345 kV transmission lines (251.7 miles)
- Sixteen 138 kV transmission lines (117.3 Miles)
- Three 345/138 kV transformers
- Two 138/69 kV transformers

Commenter (0348) respectfully requests that the EPA consider the effects of generator closures on the electric transmission system, specifically in the MISO footprint, pointing out that it already commented to EPA in a previous proceeding that loss of any significant portion of the 3.1 GW from the Dallman, Erickson, Meramec, Ottumwa, and Sioux power plants would push resource adequacy coverage of regional demands into dangerous territory. The commenter indicates that the MISO region (although fuel- and technology-neutral) needs a certain level of dispatchable and flexible resources to reliably manage the transition to a decarbonized energy future. The commenter reiterates that the MISO region is already facing challenges that include declining reserve margins and fewer always-on "baseload" resources, due to retirements of thermal units. The commenter expresses concern that the installation of new capacity from other resources is not occurring at the same rate as the baseload retirements and are not always available to provide energy during times of need. The commenter maintains that additional closures of generators would worsen an already difficult situation, continuing to place MISO in near-emergency or emergency conditions. The commenter admits that MISO will likely continue to rely on imports from its neighbors to help address system reliability concerns in the near term, this is not a sustainable situation for either MISO or its neighbors. The commenter expects an increase in the need to implement temporary controlled load sheds and rely on emergency resources and non-firm energy imports to maintain system reliability. The commenter references MISO's Seasonal Readiness Workshop as support.

In a similar comment, commenter (0348) indicates that the EPA's push towards transformations of generating fleet and the electric grid has resulted in numerous issues and associated risks that are current transmission infrastructure is not setup to address. The commenter worries that the result of this accelerated transformation without having adequate infrastructure, increases risk of not having enough generation to meet demand shifts from historic times of peak power demand to other periods – *i.e.,* hot summer evenings and cold winter mornings – when low availability of certain resources is coincident with high power demand; subsequently, unable to deliver energy to customers.

Commenter (0355) provides an overview of the electricity grids in the US and why maintaining it is important – help provide Americas reliable power to heat and cool their homes, keep their lights on, etc. The commenter mentions that to maintain a stable grid, fossil fuels are relied upon to provide more than 60 percent of the nation's electricity, and in some states, are relied upon for more than 90 percent of their electricity, due to their low-costs and reliability. The commenter worries that the proposed rule would require more power sector NO_X control retrofits (by megawatt) in the two-year time frame of 2025-2026 than has ever been achieved in any two-year period, which could force the premature retirement of many of these units.

Commenter (0370) concedes that if sufficient additional generation could be constructed by the deadlines imposed by the Proposed Rule, it expected that the commenter (SPP) and other organizations will continue to experience delays in the interconnection process. The commenter states that it is not simply a matter of constructing and interconnecting new generation; additional generation requires additional transmission infrastructure; adding it can take up to ten years or more to plan, approve, and construct transmission facilities that would be required for new generation.

Commenter (0372) insists that the EPA factor in the timeline needed for connecting new or replacement generation resources to the electric grid; further asserting that it is simply not realistic to force units offline without a replacement safety net. The commenter mentions changes made recently to improve the efficiency of their interconnection study process; adding although, they are still processing backlogged projects. The commenter states that a preliminary timeline of how the backlogged projects will be worked through the transition, and when, new projects would be studied under the changed process has been developed/approved, which, if submitted today, a project owner would not receive interconnection study results (needs and costs) until 2027 or later. After which, the commenter notes that the construction and regulatory approval processes begins (*e.g.*, Certificate of Public Convenience and Necessity and other permitting processes), which itself may take years to complete. The commenter settles that if the owner of a non-SCR unit does not or cannot install an SCR commensurate with EPA’s 2026 timeline, there is insufficient time to bring new, replacement capacity on-line – even replacement capacity located at the same site of a deactivating generation unit.

In a similar comment, commenter (0372) states their belief that the proposed FIP uses models with simplified assumptions that fails to account for significant factors in utility markets and transmission systems (*e.g.*, generation shifting analysis), and urges the Agency to consider the pressure the proposed FIP will place on transmission systems. The commenter providers a high-level overview of how electricity flows throughout the grid – in different directions on the transmission infrastructure driven by changes in ambient temperature, inclement weather, economics and plant availability to name a few. The commenter stresses the point that the unless the electrical connections exist between different geographical locations, the electrical power cannot be moved freely between them – a plant in western Kentucky cannot substitute for a plant in eastern Kentucky. The commenter states that RTOs are working to build transmission assets that allow greater flexibility of power flows, but these projects continue to face many policy issues with respect to assignment of cost and siting. The commenter adds that assumptions use in the IPM model, version 6 runs are flawed and run contrary to transmission system physics (*e.g.*, electrons flow to load), resulting in a model output that essentially redesigns the entire flow of power within a state. The commenter further notes that geographic location and the present and future projections of the adequacy of transmission infrastructure are a significant factor when attempting to "sub in" for another unit because it is a lower NO_X emitting unit. The commenter reiterates that the location of the transmission lines defines the generation options for the area – *e.g.*, the grid in that area of Kentucky is primarily electrified by three generation sources: Cooper Station (Cooper), E.W. Brown Generating Station (Brown), and Wolf Creek Hydroelectric Plant (Wolf Creek); a total of 590 MW is needed between these three generation assets to serve this area of Kentucky during typical peak load conditions. In this case, the commenter maintains that the combined 590 MW need for this area to sustain grid reliability make it so that these three generation assets cannot be offline simultaneously without creating a condition in which customer interruptions would be necessary (*e.g.*, unintended power outages or rolling blackouts). The commenter announces that the Brown Unit 3 (413 MW) may be retiring by 2028 [31]. The commenter suggests that the retirements of units, coupled with moderate increases in power demands further straining grid reliability in this area.

Commenter (0411) claims that replacing capacity lost due to unit retirement or reduction in unit output will require construction of new generation – a process that can take years to complete. The commenter mention that there have been significant investments in transmission over the last 15 years, to interconnect and transport energy from renewable energy resources to loads; however, the commenter express reliability concerns since the process for interconnecting generation to transmission in SPP and other organizations is experiencing ongoing delays.

Commenter (0412) states that, according to NERC, the industry has often defined "reliability" with two concepts: system security (the ability of the electric system to withstand sudden disturbances such as electric short circuit or unanticipated loss of some system component such as a line, transformer, or generating unit) and resource adequacy. The commenter notes that system security is comprised of 2 elements: (1) transmission security; and 2) maintenance of sufficient ancillary services. The commenter talks about the importance of transmission security, noting that it ensures that all transmission assets do not exceed their designed maximum loadings and that designated voltage levels are maintained in actual operation or in the case of a contingency. The commenter adds that generation contributes to system security through (1) changes in the amount of generation that is dispatched to produce energy in real-time to meet load, and through (2) the provision of ancillary services (*e.g.*, reactive power, regulation, frequency response, and black start) that support the transmission of energy from generation.

Commenter (0519) briefly describes distribution of power resources, noting that size and location are driving factors for new transmission to reconnect the new and more distributed sources of generation. The commenter adds that this is a lengthy process. More specifically, the commenter states that before a generator can be retired or connected to a transmission grid, permission must be granted by the system operator and reliability coordinator once the transmission needs and impacts are studied RTOs are experiencing unprecedented growth in generator interconnection queues due to the growing retirement of large fossil units and large number of smaller, replacement generation. The commenter adds that wait times in these queues are increasing the typical duration from interconnection request to commercial operation date – *e.g.,* 915 days to 1,645 days.

Commenter (0547) mentions that the Biden Administration recognized the constraints of transferring energy across our electrical system and has made transmission infrastructure a priority to facilitate interstate transmission across these interconnections and the seam separating them; refencing recent efforts to focus on grid reliability by Federal Energy Regulatory Commission. The commenter notes that there are substantial barriers that must be addressed before large-scale integration of renewable energy sources can be accomplished without negatively impacting the reliability of the electric system – *e.g.,* There is not enough available transmission capacity on the grids to connect all of the new or proposed renewable energy projects. According to the commenter it is universally acknowledged that new transmission capacity is needed across the United States to support a transition towards a decarbonized energy supply. The commenter believes that achieving the President's goals – a 50 to 52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030 and net-zero emissions economy-wide by 2050 – will require a doubling or tripling of the size and scale of the nation's transmission system; adding that there currently exists a shortage of transmission capacity for new wind and solar projects.

Commenter (0554) claims that transmission resources, particularly in the West, are already constrained, and fears that the potential impacts on the transmission system of replacing (even a few) retired or idled units. The commenter announces that they are currently reviewing the potential impacts from replacing retired or idled units and plan to present findings to EPA to consider for the final FIP, as well as provide revised cost information, as the commenter suggests that the EPA underestimates replacement costs and the amount of renewable resources, such as wind and solar, that would need to be interconnected to replace the generation currently provided by one or more fossil-fuel units. The commenter contends that even if sufficient new non-fossil-fuel resources were available, transitioning the amounts of new energy to replace what is currently generated by the affected fossil fuel units into the system cannot be accomplished within the short timeframe provided by the Proposed Rule. In addition, the commenter underscores the point that renewable resources are often not at the same location as a retiring fossil fuel unit, which would require additional transmission lines and thus additional time. The commenter cites PacifiCorp's interconnection cluster study, which found that a required $1.7 billion in transmission investments from all new resources wishing to interconnect, including new renewable resources, would be needed. To demonstrate the costs and time needed to access available transmission, the commenter briefly describes 2 recent PacificCorp transmission line projects (Gateway South and Gateway West segments D.2 and D.1) that have taken (so far) 12 to 15 years to plan and is expected to cost billions of dollars, in addition to providing an example of the costs expected and timeframe needed to accommodate a plant closure – *e.g.,* PacifiCorp's Carbon plant in Utah, required more than $39 million in transmission upgrades and took approximately three years.

Commenters (0333, 0434) describe the importance of inertia to the stable operation of the electricity system. The commenters state that grid inertia is a function of the rotational inertia of all the spinning turbine rotors that are synchronously connected to the grid. The commenters mention that the more inertia a power system has, the less it is susceptible to cascading out of control in the event of a major disturbance, such as the loss of a large generator or load; presently intermediate sources (wind and solar) do not supply inertia. The commenters conclude the higher the percentage of non-thermal units, the lower the system inertia, and the higher the probability that a power system will experience a catastrophic failure in the event of a major disturbance. Commenter (0434) (along with commenters 0333, 0394) has determined that a loss of 10,800 MW of generation (in the ERCOT region) due to the proposed FIP would reduce the gross inertia capacity of their system by 13 percent, and in some cases, the inertia reduction would require the commenter to use its out-of-market reliability unit commitment authority to deploy other thermal units to be on-line to supply the minimum amounts of inertia needed to maintain reliability. To that extent, the commenter expects that the proposed rule will result in requiring other thermal units to run, offsetting the environmental benefit of the retiring units assumed by the EPA. According to the commenter, requiring thermal units to run involuntarily will increase the costs to consumers by increasing the marginal cost of operation and will further decrease the availability of thermal generator outages, given the need for a minimum amount of inertia at all times. The commenter reiterates that if EPA cannot commit enough thermal generation to supply the necessary inertia to stabilize the grid, the grid will need to be operated in conditions that could create an unacceptable risk of cascading outages and a catastrophic system-wide blackout.

Commenter (0396) summarizes MISO's remarks on the importance of conventional power plants to grid stability; adding these plants have heavy rotating components that are synchronized to spin at the same frequency as the grid, and this rotational kinetic energy (or inertia) helps stabilize the grid when a system failure, or contingency, occurs – a feature not shared by renewable resources (wind and solar). The commenter highlights that over the last five years, capacity at MISO has decreased by 8,300 MW.

Commenter (0554) claims that existing fossil-fuel resources affected by the Proposed Rule play a significant role in providing the synchronicity needed to stabilize the electrical grid – which enables different parameters such as voltage, frequency, phase angle, phase sequence, and waveform to run appropriately across a system. The commenter clarifies, noting that fossil-fuel units have significant inertia that provides damping to stabilize the transmission system and without replacing this inertia, a heavily loaded transmission system will have more oscillations during an outage, which can trip other transmission elements and degrade the reliability of the transmission system. The commenter adds that fossil fuel units also provide the majority of the fault current – enables the system to distinguish between normal and abnormal conditions – on the transmission system. According to the commenter the early retirement of coal units would reduce the fault current by as much as 60 percent on nearby transmission system buses. The commenter suggests using synchronous condensers, as an option, to replace the synchronicity provided by fossil fuel units; however, warn that these units represent a major investment, must be extensively studied before implemented, and could take years to build – *e.g.,* 12 months of study, three to four years to build, costs between $50 million and $100 million, depending on the size, location, and system components.

Commenters (0333, 0434) argue that a significant increase in retirements of thermal generating units due to the proposed FIP will increase the likelihood that the generation supply in the their region will not be sufficient to serve customer load, and underscores the point that intermittent sources of generation are not sufficient to account for energy disparages; creating a need for quick-ramping dispatchable forms of generation (gas and coal) to offset the loss in power – *e.g.,* in the evening as solar energy dissipates. The commenters worry that if the amount of dispatchable generation capacity is reduced, the risk that they will not be able to meet its load demands—particularly in the evening hours—increases. The commenters briefly discuss the findings of an assessment they performed to quantify this risk for summer 2026, assuming the retirement of 10,800 MW of coal and gas generation; noting that the probability of the supply of generation being inadequate to serve the demand on the grid during the 7 to 8 p.m. window at some point in summer 2026 increased from 4.5 percent to 40 percent—approximately nine times the risk of an insufficiency occurring without these retirements. The commenters clarify that this vulnerability is most pronounced during this one hour but extends to other hours of the day. The commenter adds that firm load shed increases to such an alarming level would be problematic at any time of year, but during the summer months in states like Texas, when temperatures at 7 p.m. can still be at or near 100 degrees, creates a particularly acute vulnerability.

Commenter (0412) indicates that features and ancillary services, including inertia and frequency response – the frequency of alternating current on the transmission system (scheduled to 60 Hz in the US), are key indicators of the electric system's health and stability. The commenter notes that frequency deviates upward when generation exceeds demand and deviates downward when generation is insufficient. The commenter explains that frequency response is provided and maintained by inertia (from the rotating mass of synchronous, mainly thermal, generators), primary response, and secondary response.

In a similar comment, commenter (0412) states that system voltage is a key indicator of the electric system's health and stability – if voltages drop too severely, the low voltages can cascade through the system to lead to a localized or widespread blackout, and if voltages get too high, it can cause failure or permanent damage to system equipment. The commenter clarifies that voltage control is a resource's ability to either injected or absorb "reactive power" to maintain or restore system voltage to prescribed levels following a disturbance. The commenter highlights that, unlike real power, reactive power cannot be easily transmitted over long distances, and therefore requires resources used for voltage control to be located in close proximity to consumers or areas where voltage regulation is challenging.

Commenter (0412) defines black start as a reliability attribute provided by units that have the ability to start up and deliver electricity to the power grid without an outside source of power; adding that these units are intended for system restoration by helping to reenergize the grid following the unlikely event of a widespread outage or blackout.

Commenter (0554) admits that fossil fuel generation plays a critical role in stabilizing the balance of energy generation and load requirements (frequency response) due to its ability to ramp generation up or down depending on system needs quickly and reliably – which is vital to accommodate highly variable resources. The commenter clarifies noting that in comparison with fossil-fueled plants, the frequency response required from renewable resources can be variable in nature (*e.g.*, in regard to solar, cloudy vs. sunny days). The commenter asserts that because of the vital role fossil-fuel units play in integrating variable generation (*e.g.*, avoid blackouts or system oscillation), accelerated retirement of coal units could restrict the level of renewables that can be safely and reliably added to the grid. The commenter claims that the voltage support and frequency response that fossil fuel units provide actually accommodates higher levels of variable resources and helps lessen the impact of a transmission system element being out of service. The commenter suggests that a deliberative approach to phasing out fossil-fueled resources that factors in these operational and implementation realities is needed so that the frequency response and ride-through services these units provide can be adequately replaced.

Commenter (0333) states that they, along with ERCOT are statutorily obligated to ensure the availably of dispatchable generation. According to the commenter, Federal tax credits and the shorter lead times for renewable projects have made investment in renewable technologies more attractive than investment in dispatchable generation, and as a consequence, virtually all future planned generation (in ERCOT) is either solar or wind capacity. The commenter cites ERCOT's recent capacity demand and reserves report that suggests roughly 12,536 MW (or 96 percent of generation) is expected be solar and/or wind capacity by the summer of 2023.

Commenter (0351) states their commitment/willingness to achieve a meaningful balance of renewable and fossil generation to meet member and MISO obligations, and state renewable energy standards, and worries that the proposed rule will hinder their ability to meeting obligations, including load serving obligations through 2030. The commenter describes working in conjunction with Xcel Energy to plan, develop and implement a strategic initiative centered around the planned retirement (pursuant to the Consent Decree with the MPCA) of Sherco 3 (359 MW of capacity) in 2030, which according to the commenter, will result in the Southern Minnesota Municipal Power Agency reducing its greenhouse gas emissions by 90 percent from 2005 levels and being at least 80 percent carbon free in 2030. The commenter asserts that the Proposed Rule turns this strategic planning completely on its head and will result in significant cost increases to members and customers, due to having to recover the high cost of an SCR over the very short remaining life of Sherco 3, or greater exposure to MISO energy market fluctuations due to the inability to operate Sherco 3 as a hedge against those costs.

Commenter (0355) agrees that while the electric sector is poised to play a major role in transforming and reducing emissions in other sectors of the economy, *e.g.*, transportation using electric vehicles, the EPA's proposal threatens grid reliability, increases the cost of electricity, and will negatively impact these efforts.

Commenter (0408) asserts that the Proposed Rule contains numerous aspects that create challenges in meeting state resource planning obligations. The commenter, Kentucky's Public Service Commission, requires LKE submit an IRP every three years that includes the following activities:

- Screening of demand-side and supply-side resource options
- Assessment of target reserve margin criterion

- Development of long-term resource plan

The commenter defines resource planning and maintains that the dynamic budgeting, bank recalibration, daily backstop limit, and secondary emissions limit in the Proposed Rule add a layer of uncertainty to the process, due to the uncertainty of the emissions allowance budget upon which the detailed analysis would be based. The commenter states that since they would no longer be able to incorporate a known budget in their planning models, the commenter says that they will have to base models on the ongoing ozone season operation of all generating units within the state. The commenter expresses similar concerns for determining banked allocations amounts needed (sufficient for operational flexibility), since the proposed rule advocates for annual recalibration. The commenter warns that without sufficient banked allocations, purchased power from neighboring providers may be the only remaining option to meet customer load, and to the extent there is no available power for purchase or transmission is unavailable (on such high demand days), customers but also the interconnected grid, may be at significant reliability risk. According to the commenter the modeling unknowns from the proposed FIP makes resource planning exponentially more difficult and may require more generation resources to cover for system variability than would otherwise be needed – leading to higher rates and may not be achievable in the timeframe required by the proposed FIP.

Commenter (0547) believes that the EPA's failure to consider, in the proposed FIP, important aspects (limited capacity to transfer energy access grid, unreliable renewable energy sources) when considering the use of generation shifting as emissions controls, upends energy producers strategic planning towards greater investment in renewables by dramatically increasing the costs of operating fossil-fuel-fired EGUs without also considering the critical importance of maintaining reliable baseload. The commenter maintains that power companies and cooperatives rely on diverse asset portfolios to generate and dispatch electricity in a reliable and cost-effective manner. The commenter implies that even as they and other power companies drive towards greater reliance on renewable energy, coal and gas will remain critical to meet the nation's growing energy demands; adding that the energy generated by existing wind projects alone are not sufficient to maintain grid reliability. The commenter explains that even the largest wind projects constructed offer less megawatt capacity than coal- and natural gas-fired resources – *e.g.*, Units 2 and 3 of the Laramie River Station in Wyoming provide a total of 1,140 MW of power to the western system, while the wind projects constructed range from a capacity of 2.6 MW to 172 MW. According to the commenter, these resources cannot be swapped out at a one-for-one MW ratio, because each type of power generation performs an important function, and artificially driving generation away from a particular resource will have both, short- and long-term impacts on reliability. The commenter also suggests that wind and solar cannot be considered reliable sources of baseload generating capacity, because they only generate power when the weather permits. The commenter acknowledges that Coal generation may be less flexible—because it cannot be quickly cycled to follow wind in meeting market demand—but it is reliable and cost efficient. The commenter briefly talks about the importance of integrated resource planning, and how it, in part, is an exercise of predicting short- and long-term trends in federal regulations and choosing options that are most likely to be (a) permitted under the regulations and (b) built in a timely way to meet changing generation and transmission resource needs. The commenter stresses that power generators depend on regulatory certainty, the ability to employ various energy strategies (diversifying resources) to meet its members' energy needs through reliable sources, and the ability to manage their carbon footprint by incorporating resources into their diversified portfolio that have either low or no carbon emissions.

Commenter (0394) believes that efforts to comply with a final rule consistent with EPA's proposal would further strain public power, which is already under pressure from the cumulative impact of EPA and state rules. The commenter briefly remarks on EPA's recent proposal decisions on the first group of CCR Part A closure extension requests, which according to the commenter will have profound effects on the electric utility sector, including public power utilities. The commenter clarifies noting that facilities that do not receive approvals of their Part A CCR closure extension request, will be given 135 days to cease the receipt of coal ash waste into surface impoundments. The commenter worries that the loss of the disposal capacity could force affected facilities offline potentially during the 2023 ozone season depending on when EPA issues its final CCR Part A determinations, thus exacerbating electric reliability concerns. The commenter maintains that the proposed rule regulatory incentive to retire units by 2028 adds to the existing pressure and electric reliability concerns. According to the commenter, flexibility is needed as the fleet transitions to increasingly less fossil-fuel-fired generation. The commenter recognizes that when public power utilities lack capacity, they have to purchase power on the market, which are already prohibitively high (and likely to continue to increase), due in part to the increasing ammonia costs, which is needed to run SCRs, and the high cost of natural gas.

Commenters (0333, 0434) express concerns that the proposed rule would impact regulated entities' ability to conducted periodic generator maintenance, which is essential to ensure thermal generating units such as coal- and gas-fired generators can continue operating during peak periods when they are most needed. The commenters state that a 1,000 MW thermal unit typically requires 30 days of maintenance outages each year. The commenters explain that whether any particular thermal generator can be allowed to take an outage during a specified timeframe largely depends on whether other thermal generators are available to operate during that period – not accounting for lower levels of generation from non-thermal sources, such as wind and solar, during the maintenance outage. The commenters warn that if the amount of available thermal outage capacity drops below a level that allows the remaining thermal units to conduct the maintenance they need to operate reliably during peak periods, this can have catastrophic long-term consequences for the reliability of the grid. Point to a recent analysis conducted by the commenter themselves, the commenter states that they found that, based on the expected retirements, only approximately one-third of the needed maintenance outages would be permissible in 2026, which can dramatically increase the probability that a substantial number of the remaining two thirds of generators will experience a forced outage at some unpredictable time. The commenters conclude that depending on the timing and magnitude, these forced outages could destabilize the grid and/or require firm load shedding to avoid total grid failure.

In a similar comment, commenter (0409) states their belief that reliability-based requirements in organized regions like RTOs and ISOs will make it infeasible for EGUs to opt for further NO_X emissions controls technologies simply and unilaterally. The commenter provides an example, and states that owners' ability to take an outage for SCR/SNCR installation is not certain and is subject to denial if, for example, there would be insufficient generation remaining on-line from a reliability perspective. The commenter further asserts that short-term maintenance outages simply will not accommodate installation of one new SCRs, which EPA optimistically estimates could take as little as 21 months at an individual plant and 36 months at a single plant with multiple boilers, or even two state-of-the- art NO_X combustion controls under EPA's perhaps unrealistic estimate that such installations would take two to three weeks.

Commenter (0322) states that a critical factor in the recent success of Kentucky's economic development is access to available, affordable, and reliable energy; however, the commenter worries the proposed FIP threatens this critical factor and negatively impact Kentucky's economic development. More specifically, the commenter fears, if enacted as proposed, the proposed FIP would results in rapid decreased electric generating capacity without sufficient time to transition to a lower emissions (NO_X, carbon, PM, etc.) generation mix; increasing the risk of major impacts, including rolling blackouts from the supply and demand imbalances generated by this proposed rule. The commenter further worries that the proposed rule has the potential to result in 2,600 MWs of capacity shortfall by 2026 if utilities with older electric generating units do not add unjustifiably expensive controls, convert to natural gas, install low NO_X emitting electric generating units, or participate in a flawed emissions trading market. The commenter provides the following recommendations:

- Eliminate Bank Reallocation.
- Eliminate Dynamic Budgeting.
- Provide allowance for startup, shutdown and malfunction events.
- Eliminate punitive "backstop limit," and secondary emissions limit provisions that surrender allocations at a 3-1 ratio.
- Adjust unrealistic combustion control and existing SCR control limits

Commenter (0329) supports the proposed rule and the EPA's efforts to reduce air pollution; however, they express concerns that the proposed rule will unnecessarily increase reliability risks and ratepayer costs. The commenter feels that the proposed NO_X budget restrictions and the tight timeline required for compliance would encourage or force earlier-than-planned coal plant retirement—or ozone-season curtailment—for several major power plants in Minnesota, most of which are member of the MISO – a FERC approved regional transmission organization that has primary responsibility for maintaining electrical reliability in our region. The commenter reaerates that MISO is currently facing a capacity shortage due to states in the central region of MISO procuring insufficient capacity to meet their needs, and according to the commenter, the proposed rule could make the existing capacity shortfall worse. More specifically, the proposed rule does not allow enough time for their utilities to procure replacement capacity for coal plants that could be forced to retire earlier than scheduled per state approved plans. The commenter expects that obtaining 500 MW or more of accredited capacity by the end of 2026 would be difficult and expensive. The commenter underlines the point that eleven of the fifteen states covered (Minnesota, Wisconsin, Illinois, Missouri, Kentucky, Indiana, Michigan, Arkansas, Texas, Louisiana, and Mississippi) by MISO have power plants covered by the proposed rule; thus, the rule could have a significant impact on

MISO's energy and capacity markets and negatively affect the reliability and cost of electric service in Minnesota and the MISO region.

Commenter (0370) maintains that it seems unlikely that resources needing SCRs will be able to install the necessary equipment in time to meet the deadlines imposed by the Proposed Rule, partly due to labor and supply chain issues – issues that will be exacerbated, in terms of both availability and cost, by the tight timeframe contemplated by the Proposed Rule, resulting in the premature retirement of units. The commenter adds that any cost increases will be borne by ratepayers. The commenter worries that the amount of allowances available for purchase would not be sufficient, if SCRs cannot be installed.

Commenter (0394) states their belief that proposed FIP jeopardizes both system reliability and the affordability of the transition by potentially expediting generator closures before proven dispatchable clean energy technologies are available. The commenter asserts that a more costly, less reliable electric system will undoubtedly have a negative impact on the health and wellbeing of Americans by increasing the cost of energy and impacting every facet of our lives – *e.g.,* Higher electric costs will impact the ability of people to afford heating in the winter and cooling in the summer, resulting in adverse effects on health, including increased hospitalizations and premature deaths. Similarly, the commenter maintains that disruptions in electric delivery due to generation capacity shortages will impact the operation of health care delivery organizations, the productive capacity of the US as well as the food storage and supply systems.

to Commenter (0505) contends that the EPA fails to account for the impacts of potential increases in electric pricing, or even a lack of available generation leading to possible brownouts or blackouts, on all consumers in Texas. The commenter argues that these impacts will disproportionality affect resource limited consumers, making them more susceptible to experiencing health related issues associated with a lack of access to electricity, particularly during the summer months, prime ozone season, when EGUs will be most pressed to both operate and to meet the emissions limits of the proposed rule. Similar effects are expected, according to the commenter, with generation shifting or other attempts by EGUs to meet rule requirements, particularly if they end up with decreasing generation.

Commenter (0529) express their concern that customer costs and reliability impacts from generation resources will extend beyond state borders and impact states (like North Dakota) not subject to the proposed FIP. Specifically, the commenter is concerned that the proposed rule will further undermine grid reliability and the economic feasibility of quality, firm generation as provided by the existing generation fleet.

Commenter (0550) states their belief that the proposed FIP increases adverse risks to grid reliability by forcing generation shifting, encouraging the acceleration of EGU retirements, and disincentivizing operation during the hottest days when generation is most needed to ensure public health and welfare associated with detrimental heat-related impacts. The commenter questions the Agency's authority to make decisions on generation mix – a responsibility typically assigned to states. According to the commenter, the risk of power outages and/or high electricity prices are likely to disproportionately impact the most vulnerable – *e.g.,* residents with preexisting health issues and/or low-income, communities of color.

Commenter (0760) argues that the EPA fails to adequately analyze the impact on electric grid reliability along with the health impacts and cost to electric consumers, including Louisiana ratepayers who will bear the economic burden of this rule. More specifically, the commenter worries that the Proposed Rule, as written, will result in expenditures of hundreds of millions of dollars to Louisiana industries, additional electricity costs to Louisiana electrical consumers, and the creation of secondary PM and ammonia emissions within Louisiana without generating significant benefits – ozone concentrations around the single monitor in HGB is expected to improve by only about 1 part per billion.

Commenter (0351) insists that the Sherco 3 unit (scheduled to retire) serves as the most important and effective hedge against market price fluctuations, in addition to being a source of reliable energy to the MISO market – Sherco 3 is positioned in a critical location for providing capacity and energy. The commenter worries that ratcheting down/limiting Sherco 3 to a 31 percent capacity factor means that the commenter will be exposed to ongoing volatile market prices. The commenter further adds that because MISO rules may not grant credit for the generating capacity of Sherco 3 due to such limited operations, the commenter will face the daunting challenge of trying to replace 359 MW of capacity, which typically is not a problem due low costs and high capacity availability; however, the commenter recalls that recently MISO announced a capacity availability shortage for its auction and is warning of potential rolling blackouts because of lack of supply to meet projected demand. The commenter further notes that capacity shortage has caused auction rates within MISO to increase from $0.15/kW-month in 2021 to the maximum $7.20/kW-month in 2022 – a 4,700 percent increase.

Commenter (0412) implies that the implementation of the proposed FIP requirements will inadvertently interfere with existing and/or upcoming applicable reliability standards. The commenter states that are required to comply with federally-approved reliability standards promulgated by the NERC and the applicable Regional Entity. The commenter quickly outlines specific characteristics and functional responsibilities, as specificized in FERC Order No. 2000, and provided a brief discussion on their governance structure.

Commenter (0412) provides a brief overview of their company's structure and their authority/role. The commenter explains that they are the balancing authority and reliability coordinator for a 13-state footprint – from which they can direct actions to ensure that the generating units within its footprint are operated in a manner which meets approved reliability standards. The commenter points out that generators in the footprint have largely been deregulated at the wholesale level as a result of FERC rulemakings and orders. The commenter adds that they can direct that certain actions be done to avert emergencies, but they cannot force the construction, continue operation of, and updates to a particular generating unit. The commenter (along with commenter 0372) notes that a 90-day notice is currently required to announce the retirement of a unit; adding that the retirement of the unit must not impact the reliability of the transmission system. Commenter (0372) provides a detail description of their deactivation process; adding that additional time is needed by RTO to complete this process than allotted under the proposed rule.

Commenter (0414) emphasizes that closing of large amounts of existing dispatchable generation, as expected due to the Proposed Rule, in such a short timeframe raises serious reliability concerns that are especially heightened given that additional amounts of dispatchable coal-fired generation could retire because of the rule and other upcoming EPA rules being implemented, over the next five to ten years. The commenter (along with commenter 0395) criticizes the Agency for not evaluating a process for evaluating the electric grid reliability impacts of the Proposed Rule. So, commenter (0414) proposed the following two-step for addressing potential adverse impacts of the proposed revisions to CSAPR program on the reliability of the electric grid. First, the commenter asks that the EPA perform an assessment that analyzes and assesses the cumulative electric grid reliability impacts of the Proposed Rule in combination with the other upcoming major EPA rules applying to the electric power sector. The commenter requests that the EPA perform the assessment of cumulative reliability impacts prior to the start of the newly revised CSAPR regulatory program, and then update that assessment on a periodic basis during the implementation of the CSAPR regulatory program. Second, the commenter recommends that the Agency establish a reliability adjustment mechanism to address significant electric grid reliability concerns resulting from the cumulative impacts of the EPA rules.

Commenter (0554) contends that if a utility were forced to retire or idle fossil-fueled units before 2026 under the Proposed Rule timeline it would immediately increase the risk of blackouts and grid instability for both the utility and the region and procuring replacement power would be necessary. According to the commenter, utility would likely have to rely on the wholesale energy market for replacement power because the Proposed Rule does not provide sufficient time to build new resources and transmission; however, the loss of even a fraction of dispatchable generation in the region will strain energy markets by decreasing market depth and increasing wholesale energy prices. The commenter contends that costs to meet customers' energy needs would be immediately higher, as the lack of capacity would cause scarcity pricing to take hold. The commenter concludes that finding replacement power would not be just a matter of price but also a matter of availability and deliverability.

Commenter (0519) references FERC, NERC, and various RTOs, noting that these government authorities/organizations all have expressed concerns about reliability challenges – including electricity supply shortages, current RTO backlogs for generator interconnection queues, and delays associated with planning new transmission, along with impacts felt by the electric industry at-large from current global market conditions – supply chain issues and labor shortages.

Commenter (0529) The NDPSC submits that the transition of the bulk power system can take years of planning, construction, and considerable investment; adding that regional constrained interconnection queues and supply chain disruptions have also made market conditions challenging to bring new resources on-line to replace retiring capacity effectively.

Commenter (0317) asks that the EPA provide for flexibility in the event of an emergency or major disaster as declared by the RTO and references the Steam Electric Power Generating Effluent Guidelines and Standards (40 CFR part 423) for emergency/must-run orders associated with units that will permanently cease the combustion of coal by 2028, as an example.

Commenters (0333, 0434) urge the EPA to include an RSV that would allow grid operators like ERCOT to utilize generators that lack sufficient allowances to operate at the needed level of output when necessary to serve customer load in the unusual event of a grid emergency; adding (along with commenter 0412) that an RSV was successfully used in the CPP rule. Commenter (0434) recommends that an RSV should be available when the grid operator has declared an emergency (*e.g.,* when total system capacity reaches a very low threshold relative to load and the required level of reserves) under the grid operator's rules, or when they (grid operators) are not able to operate the transmission system within its defined limits using its normal operational tools. The commenter states their belief that limiting the availability of an RSV to an emergency condition would ensure that the exceedance of any allowance is narrowly tailored to the most exigent of operating circumstances.

Commenters (0348, 0372, 0396, 0409, 0412, 0413) strongly support including some form of a "Reliability Safety Valve" in a future final rule to support the reliable operation of the bulk electric system – to allow EGUs to produce electricity (without penalty) to the grid when grid emergencies avail themselves. Commenter (0372) adds that blackouts, brownouts, and loss of life should be avoided to the extent possible.

Commenters (0348, 0412, 0413) underscore the point that the RSV mechanism would not be a blanket exemption from compliance, but rather, it represents certain tools and processes that would be available to address reliability issues (based on short-term declared system emergency conditions) that might arise during the implementation of a final rule.

Commenter (0348) proposes that the EPA create an "opt-out" option for units willing to commit to a short remaining useful life (beyond 2026) in exchange for additional consideration/allowances in setting state NO_X budgets. Furthermore, the commenter proposes that an RSV be available that would: (1) Permit the operation of affected units beyond the proposed rule's constraints if the ISO/RTO has an applicable and declared emergency condition under its FERC-approved Tariff; and (2) Be available for up to 90 days, Triggering and Notification Criteria are outlined that would reasonably constrain the exemption. As a flexible option in emergency circumstances, the commenter suggests the creation of a 'bank of emergency reliability allowances' available for units to purchase at the start of the summer season would allow for an e-trading program, but with more allowances to be made available than the currently proposed trading program.

Commenter (0348) also recommends the following mechanisms to alleviate reliability and adequacy concerns could include:

1. EPA revising their proposed dynamic budgeting approach to look back at multiple years of past unit operating data (rather than a single year).
2. EPA revising their proposed dynamic budgeting approach to adjust state budgets less frequently, perhaps every 2 or 3 years rather than annually.
3. EPA retaining retired units in state budgets for a longer period than they have proposed, such that sources that do retire units as part of their CSAPR compliance strategy have more flexibility to utilize the allowances associated with the retired unit to meet their allowance surrender obligations for other units which continue to operate.
4. EPA revising or even eliminating their proposed annual "recalibration" of the number of banked allowances.

Commenter (0348) requests that the EPA find that the conditions for an energy emergency resulting from a loss of necessary energy supplies under CAA section 110(f) of such severity that a temporary suspension of part of the applicable implementation plan and/or requirements under CAA section 7651j is presumed to be necessary AND that there is no other adequate means of responding to the energy emergency would be presumed to exist when the ISO/RTO has an applicable and declared emergency condition under its FERC-approved Tariff.

Commenter (0395) encourages the EPA to discuss and provide a mechanism to allow the Agency to work with regional grid operators to determine the availability of power generation in 2025 and to anticipate available generation for 2026, and for years following. The commenter maintains that one of the benefits to proposing a reliability safety valve is that in the event that the grid operator identifies grid reliability concerns with the NO_X budget decrease for that ozone season, the grid operator would be able to make a declaration that would delay or revise implementation of the FIP measures until such time as sufficient generation is on-line – an option that allows for power plants to prepare to operate during the 2026 peak season (in Texas) instead of idling or shutting down.

Commenter (0409) insists that a “reliability safety valve" must consider:

(1) Triggering events

(2) Clarity regarding the

  (i) relief that can be granted (*e.g.*, complete relief from implementation for a determined period of time; access to a “bank” of emissions allowances available at a fee; relief from penalties; other reliability-based mitigation measures); and

  (ii) remedial actions taken to remedy the circumstances necessitating the relief granted

(3) a process for requesting relief.

Commenter (0412) explains these emergency situations are virtual (by definition) and are measured in hours not days. The commenter further explains that if the RTO/ISO (or balancing authority in non-RTO regions) identify a reliability-based need to run one or more generating units during a defined emergency condition then the Short-Term RSV (an established concept) would allow the affected units to operate for the hours during which the emergency is in effect beyond the rule’s operational constraints without having to expend their bank of available allowances. According to the commenter, an RSV would be constrained to periods when a reliability emergency consistent with its governing rules and emergency protocols has been declared. The commenter requests that the Short-Term RSV become available with appropriate alerts, warnings, and actions to effectively manage system reliability by enabling timely preparation and operation of required resources. The commenter underscores the importance of an RSV; adding that without it the only recourse available to direct a unit to run that cannot, due to an emissions-based limitation would be to seek relief pursuant to Section 202(c) of the FPA; triggers a multiagency process. The commenter stresses that the Short-Term RSV recommended would not substitute for use of the Section 202(c) authority, but instead would provide a rational pre-defined and limited interim step, embedded in the future final rule, that would allow for short-term relief as opposed to the longer-in-duration requests (up to 90 days) that are envisioned under the DOE Secretary's Section 202(c) authority.

Commenter (0550) states their belief that the EPA should incorporate a safety valve at both the unit-specific and sector-wide level to help address reliability concerns – *e.g.,* certain units may be required to derate during ozone season to ensure compliance with the new, more stringent requirements, yet there may be significant demand events during the summer ozone season; creating an urgent need for all available sources to operate at capacity. As an example, the commenter describes a 2022 event where the demand in the state of Texas reached a record 74,820 MW. Fortunately, there was sufficient capacity available able to meet the demand, however the commenter underscores the point that such demands create an urgent need for all available sources to operate at capacity. The commenter asks that sources not be penalized or found in violation of their CAA obligations when they are required to run in an emergency to avoid threats to reliability.

Commenter (0551) claims that the EPA fails to consider (in the proposed rule) the risk to electric reliability or a functioning allowance market. The commenter observers that the docket for the proposed FIP does not appear to contain any substantial analysis of electric reliability impacts or an assessment of how allowance markets are likely to function under the Proposed Rule. The commenter advises the EPA to undertake a more thorough examination of electric reliability and market functionality to support its proposed regulatory action – consider the ongoing changes to the electric generating fleet and the timeframes for compliance. The commenter further suggests the EPA collaborate/consult with the appropriate organizations and agencies to consider the impacts of grid reliability (unplanned loss of generation, rolling-blackouts). The commenter contends that consultations and further evaluation could determine if additional regulatory action is needed, such as a safety valve that would provide additional allowances if reliability were to be jeopardized by allowance market shortages without significantly impacting the environment; noting the EPA provided for a safety valve to address market liquidity concerns in the Revised CSAPR Update. The commenter explains that the EPA could always reserve the right to require remedial action to address any significant contribution that would result from this sort of emergency operation or to evaluate whether it would be possible to address such operations and emissions pursuant to other CAA authority, like the exceptional events provision.

Commenter (0554) criticizes the rule for constraining compliance options for affected units, stating that without the option to trade allowances, sources will be forced to install controls that are not cost-effective or simply cannot be installed on EPA's suggested time frame, or both, which in turn will force unit retirements. The commenter requests that the EPA adopt a safety valve for this rule and provides an example of such a safety valve from the Clean Power Plan. According to the commenter, while the CPP was never implemented, the safety value concept it included was reasonable and sound. The commenter relates that it allowed for a 90-day grace period during which a reliability-critical unit would be excused from compliance, allowing time for the unit owner and the state to develop a long-term solution through a revision to the state plan. According to the commenter, the EPA adopted that safety valve to ensure the absence of adverse energy impacts where the built-in flexibilities are not sufficient to address an immediate, unexpected reliability situation. The commenter adds that most recently, the

EPA adopted a safety valve mechanism for the Revised CSAPR Update that allowed the conversion of Group 2 to Group 3 allowances at a higher conversion ratio to help facilitate development of a viable market to support the Group 3 program. According to the commenter, the stated purpose of that safety valve was to “further ensure allowance market liquidity and compliance flexibility.” The commenter acknowledges that in footnote 293 of the proposal, the EPA states that it “is not proposing to create a ‘safety valve mechanism’ in this rulemaking analogous to the safety valve mechanism established under the Revised CSAPR Update,” and requests that the EPA reconsider and reverse this decision given that no justification for doing so was given in the proposal.

Commenter (0330) provides that, beyond potential reliability concerns, the market volatility also could cause significant economic hardship for smaller generators. Many of the commenter’s assets are smaller units with limited operating budgets. According to the commenter, spikes and volatility in allowance markets do not serve the ultimate customer in terms of electric rates. For example, the commenter notes that, since the start of the 2022 ozone season, based on the sudden and unexpected increase in NOx allowance prices, several of our units are now projecting a shortfall of ozone allowances that could cost $11 million dollars when at the time of budget planning in 2021 for the 2022 ozone season, the projection was $1.3 million based upon a price of $2,300 per allowance in the fall of 2021. During budget projecting in 2021, this type of increase was not anticipated as there was no indication based on historical NOx allowance prices that this drastic allowance price increase would occur. This financial burden is a driver for utility management to consider curtailment of operations and/or not bidding into the market, thus potentially leading to grid stability issues during the peak summer demand season. The commenter notes that this is just their example of multiple plants that are facing allowance shortfalls this year; many other units in Group 3 will face the same basic choices.

Commenter (0330) notes that not being able to secure enough allowances could be an issue if EGUs are not willing to sell surplus allowances in any given year because of the uncertainty if they will be needed in future years. The commenter states that real-time concern with having enough allowances may drive decisions in market operations should the penalties be unreasonable. According to the commenter, these issues pose a real concern for grid reliability and stability.

Moreover, commenter (0546) claims for a unit with a limited remaining useful life (RUL) where a major capital investment in NOx emissions control retrofits is not economically feasible, the likely lack of any significant quantity of surplus allowances will significantly constrain the ability to continue to operate the unit during the 2026 or subsequent ozone seasons. In closing, commenter asks that the EPA consider the potential that the proposed NOx state budget presumptions and allowance constraints will cause operators to accelerate retirement decisions for units that are currently only planned to operate for a limited number of years beyond 2026, and the potential for such accelerated retirements to create issues with the reliability of the bulk electric system. Commenter recommends that the EPA consult with the RTOs and other electric reliability stakeholders on these issues and incorporate appropriate revisions into the final FIP to mitigate potential reliability issues.

Commenter (0372) is concerned with the proposed FIP's disconnect between energy supply, environmental compliance, and economic development in Kentucky. According to the commenter, Kentucky needs to remain competitive with surrounding states for new jobs, economic development, and low-cost energy, and the EPA should factor costs, and generation supply with transmission constraints into the analysis for the proposed FIP.

Commenter (0430, 0546) express their concerns that the proposed FIP does not include a "safety valve" mechanism for maintaining allowance prices and recommends that the EPA establish an allowance reserve or price ceiling so that allowance prices do not reach unexpected or unaffordable levels –especially considering the compounding impact uncapped allowance costs could have on rising energy costs. The commenter (0430) warns that the proposed 'dynamic budgeting' to reduce allowance banking may exacerbate the liquidity issue and lead to a scenario of unreasonably high allowance prices in the market. The commenter explains that electric companies are experiencing a profound, long-term transformation in how electricity is generated, transmitted, and used, and recommends that the EPA consider a scenario in which, despite broad, continuous operation of emissions controls, some sources cannot reasonably meet their obligations to provide affordable and reliable power while also meeting the proposed requirements of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards. More specifically, the commenter proposes that the EPA create an allowance reserve that would allow sources to acquire additional allowances (*i.e.*, at a cost above that of SCR control but still deemed affordable) in the event that allowances are prohibitively expensive in the market. According to the commenter, in 2022, the commenter used the "safety valve" mechanism of the CSAPR Update to acquire additional allowances for the 2021 compliance year and concludes that this mechanism is helpful and appropriate to reduce compliance cost while maintaining the same level of control. Commenter (0546) asserts that without a safety valve provision, the owner/operator could face a situation where operation of a unit is necessary to meet system demand, but the unit is not yet equipped with a functional SCR due to installation delays; resulting in a significant allowance shortfall.

Commenter (0412) expresses concern that it is difficult to know, based on the proposal as written, whether the quantifies of allowances made available so that units may operate, will be sufficient to ensure system reliability, and therefore, requests that the EPA ensure reliability through an adequate supply of allowances and mechanisms to ensure the liquidity of the allowance market at reasonable prices. The commenter adds that while the size of the allowance bank is impacted by the EPA's determination of the level of emissions which would meet the rule's goal, it also impacts a unit's availability to meet the reliability needs of the system. More specially, the commenter requests that the EPA implement a dedicated bank of reliability allowances specific to each region that would be available to generators should the RTO/ISO (or balancing authority in non-RTO regions) project a potential shortfall in reserves in a given region over the summer season coupled with insufficient availability of allowances to sustain unit operation through the summer season. The commenter expands to note that access to these regional reliability allowances, would only be triggered if:

a. The availability and cost of allowances available on the market [are not] sufficient to sustain units that will be needed throughout the summer season and particularly when called upon by the RTO in emergencies;

b. The price of allowances and the lack of liquidity [makes] it difficult for units to purchase sufficient allowances at reasonable cost to ensure reliable operations through the summer period; and

In areas of the system where there is limited import capability, the allowances otherwise available to units within the constrained area are insufficient to sustain reliable operations during the summer season.

The commenter provides the following framework for the proposed dedicated bank of reliability allowances:

- Availability of Reliability Allowances – reliability allowances may be used within that region and only during the ozone season of May 1 through September 30.
- Access to the Bank – the RTO/ISO or balancing authority, working with EPA, would model the availability of allowances based on the above considerations prior to entering into the summer season. Based on that analysis, if deemed necessary, the RTO/ISO or balancing authority could petition for creation of a discrete bank of regional reliability allowances to ensure reliable operations through the summer period. The request must document the nature of the forecasted reliability or tight resource adequacy condition that could require units to be available to run but may not be able to do so due to an emissions limitation and lack of a reasonably priced liquid allowance market going into the summer season.
- Forecasted Reliability Condition – the forecasted reliability condition would be identified through the established resource adequacy, planning, and reliability practices in use by the relevant responsible entity such as the ISO/RTO or in non-RTO regions, the balancing authority.
- Quantity – the quantity of reliability allowances available in the bank would be based on the forecasted reliability condition, the expected operation of generating unit(s) and forecasts of demand response availability during the summer season, the availability of other allowances pursuant to the rule. The recommended quantity of these regional reliability allowances would be coordinated with EPA to ensure consistency with the objectives of the final rule.
- Pricing – generators would purchase reliability allowances, which would be priced using an auction mechanism. Although these allowances would be available for use strictly in the region, the auction could be administered using the present institutions administering auctions and allowance trading programs.
- Triggering Mechanism – the regional reliability allowances represent a supplement not a replacement for emissions allowances otherwise allotted under the rule. Their creation in a given season is not guaranteed–if there are no projected shortfalls in allowances given the RTO's/ISO's projection of summer demand and the market is sufficiently liquid at a reasonable allowance price, no regional reliability allowances would be created. On the other hand, the RTOs/ISOs regional summer demand forecast, coupled with an analysis of regional reserve margins, allowance availability and cost, would all be factors that

could trigger the creation of this regional reliability allowance supplemental bank at the beginning of the summer season. This bank of regional reliability allowances would be made available at the start of the summer season. Because their use would be restricted to only that region and only for the immediate upcoming summer season, they would truly represent a 'last resort' bank of allowances as opposed to a substitute for the allowances otherwise made available under the Proposed Rule.

- Unit Reporting – a unit's use of reliability allowances shall be reported on a monthly basis.
- Unused Reliability Allowances – unused reliability allowances may not be traded or sold and are invalid at the end of the applicable ozone season with no refunds for purchased reliability allowances. This would prevent this special bank of regional reliability allowances simply becoming a substitute for the general bank of allowances.
- Recovery of the Cost of Reliability Allowances – Recovery of the costs of allowances would track the recovery of other allowances such as NO_X and SO_2 allowances. In market regions, they would be includable in cost-based energy market offers.
- Disposition of the Proceeds of Purchased Allowances – As end-use customers will see higher energy prices in the region due to the CSAPR rule, the proceeds of the allowances could be rebated to customers. Today certain out-of-market costs are uplifted to customers. In the same way, these proceeds could be a credit to customers using existing uplift mechanisms.
- Priority Over the Short-Term RSV – ISOs/RTOs, reliability coordinators, planning authorities, and units shall use reasonable efforts to prioritize the use of reliability allowances over reliance on the short-term RSV described below to promote effective resource adequacy planning in conjunction with the obligations set forth in a final rule.

Commenter (0333) provides the following areas of concern that they were not able to provide detail comments on due to the limited public comment period.

- The reliability impacts due to reduced output and possible retirements that could occur prior to 2026 due to emissions budget restrictions beginning in 2023 and daily unit restrictions beginning in 2024.
- Reductions in ramping capability, voltage support, and frequency response.
- The need for additional ancillary services that would likely be required to address the increased reliance on intermittent sources of generation, such as wind and solar.
- The increased operational risk due to the greater reliance on intermittent sources of generation, apart from the need for additional ancillary services.
- The impact of outages on consumers that will occur while the needed transmission facilities are being constructed, given the five-year lead time of most transmission projects.
- The increased cost of energy associated with the procurement of allowances.

- Even if the installation of SCR technology were economically feasible, (and for many EGUs it will not be) the compliance timeline for installing this equipment is unreasonable and unworkable. For ERCOT (and other ISOs and RTOs) the 2026 deadline for installing SCRs nationwide could create serious reliability problems because of the need to coordinate outages for affected EGUs to install SCR technology given the number and capacity of resources. Some of these outages may be lengthy, but it is difficult to assess the exact impact as installation timelines for this equipment are unit specific and vary considerably. These reliability concerns must be fully analyzed and addressed before any rule is finalized.

Commenters (0346, 0359, 0372, 0400, 0409) suggests that the proposed rule is an attack on the oil and gas industry and that the industry is being vilified without cause. Most of the commenters remind that fossil fuel generation plays a crucial role in sustaining the grid reliability and energy security – 60 percent of the electricity generated in the United States derives from the combustion of fossil fuels, including natural gas, coal, and petroleum. At least one commenter (0372) asks that the EPA recognize and protect coal-fired assets that already have state-of-the-art air pollution controls. Commenter (0400) asserts, based on statements made by Agency representatives, that the ultimate goal of the proposed rule is to force coal-fired generation units offline – a dangerous approach considering the already-strained state of the electric grid. Commenter (0409) states their belief that proposed rule is clear in its goal of unit retirements; arguing that the EPA's proposed new assurance concepts/enhancements leave no room for flexibility. The commenter contends that a reduction of allowances in the CSAPR trading program will essentially end the use of trading as a compliance tool and force technology installation. The commenter maintains that sources must be given flexibility to choose how to reduce NO_X within their systems; further implying that flexibility plays a critical role in maintaining grid stability by reducing strain on the grid and allowing for continued reliable operation.

Commenter (0409) asks that the EPA include/describe plans to coordinate with RTOs/ISOs, agencies like FERC and critical reliability organizations like NERC, as well as perhaps others (state entities) to monitor implementation and compliance, as they did when finalizing the CPP – *e.g.,* efforts included the EPA consulting with DOE and FERC staff in the development of its rules, as well as continued coordination to ensure compliance with the CPP "in a manner that is fully compatible with the power sector's ability to maintain electric reliability."

Response:

EPA disagrees with the comments asserting that this rule would degrade electric system reliability by forcing retirement or preventing operation of EGUs needed for reliability. The rule's requirements for EGUs are structured as a flexible allowance trading program. The rule does not mandate retirement or installation of new controls for any individual EGU; it simply requires the surrender of quantities of allowances determined based on units' emissions. The rule does not displace existing processes for the planning of generation and transmission. The rule does not override any aspect of the existing processes put in place by RTOs, balancing authorities, and state regulators to protect electric system reliability in the event the owner of a particular EGU seeks to retire the unit. Further, the EPA has adopted changes in the final rule from proposal for a transitional period to increase planning certainty and compliance flexibility, including preset minimum state emissions budgets, the deferral of backstop emissions rate requirements for units without SCR controls, and higher bank recalibration targets. For discussion of EPA's response to comments on electric grid reliability as well as these changes from proposal, see Section VI.B.1.d of the preamble. For discussion of EPA's findings concerning the magnitude, cost, and timing of emissions reductions achievable from EGUs and the reflection of those findings in emissions budgets, as well as the final rule's adoption of a phased schedule for the degree of emissions reduction associated with new SCR installations and the adoption of multi-year heat input baselines to reduce year-to-year variability and increase budget predictability, see Sections V, VI.A, and VI.B.4 of the preamble. For discussion of EPA's findings concerning the backstop daily emissions rate requirement, deferral of its applicability to units without existing SCR controls, and addition of a 50-ton threshold before additional allowance surrender requirements apply, see Section VI.B.7 of the preamble. For discussion of the projected economic impacts of the rule, see the RIA.

10.5 SCR Installation Timing

10.5.1 Comment Overview

Comments:

Overall commenters (0246, 0290, 0317, 0320, 0323, 0327, 0351, 0354, 0361, 0370, 0371, 0372, 0376, 0380, 0385, 0387, 0394, 0396, 0409, 0431, 0499, 0504, 0511, 0519, 0524, 0539, 0541, 0546, 0547) assert that the EPA drastically underestimates the time required and/or costs to installed new NO_X controls or retrofits at existing EGUs. While most of the commenters ask that the EPA consider extending the timeframe allotted to install new SCRs or post combustion control retrofit (SCR/SNCR) from 36-months (three years) to four or five years, in an effort to be more consistent with past actions (like the Regional Haze Rule), at least one commenter (0506) asserts that the EPA drastically overestimated the time required to time – supporting a 21-month schedule instead. Commenter (0323) urges that criteria (permitting requirements, supply chain issues, etc.) warrant consideration for extension requests for as much as an additional three years if needed to permit and install controls on boilers. A couple of commenters describe facility- or unit-specific situations that could potentially impact compliance – provide a number of examples where owners completed SCR installations or retrofits and the time and effort needed extended beyond what EPA assumes and proposes.

Some commenters worry that the timing/schedule of retrofits in proposed FIP would result in multiple units being offline simultaneously, possibly impacting grid reliability in an effort to complete the installation of controls by 2026. Many of the commenters claim that the EPA underestimates the costs of controls (SCR and SNCR), largely because the analysis used is based on old, dated information and the proposed FIP fails to consider impacts/disruptions from supply chain issues, labor shortages, and current market (inflation) and global impacts (war in Ukraine's). A few commenters asks that the EPA consider (in the installation timing consideration of 36 months) time needed by cooperatives to finance the installation of SCRs via RUS.

A small number of commenters argue that the proposed FIP compliance schedule/timeframe fails to consider the remaining useful life of an EGU beyond 2026, and the commenters largely object to requiring units that have five years or less remaining life (especially retirements enforceable by consent decree) from installing control devices; claiming that it is not cost-efficient for owners, and the benefits (emissions reductions) that would result from these controls are not significant enough to justify the investment. Additionally, several emphasizes that the EPA's proposed FIP fails to address the site-specific challenges (*e.g.*, unit location) that can also delay timing for SCR installation, making meeting proposed deadlines more difficult.

Commenter (0546) asserts that the EPA's proposed timing for SCR retrofits is unreasonable. Based on recent experience, the commenter reports that the development and deployment of utility-scale solar generation would be expected to take 5 to 5.5 years, on average, from initial planning to commercial operation. According to the commenter, similar development and deployment of modern hydrogen-capable gas generation capacity would be expected to take up to seven years from the date that planning for such a project was initiated, noting that such projects are large and complex, and require numerous permits, approvals, and authorization from both state and local regulatory authorities, along with significant engineering, procurement, construction, and equipment testing. In addition, the commenter remarks that external factors can create unexpected delays in the ability to execute new generation projects. While the commenter anticipates that much of its future generation resource needs will be met via additional solar and wind resources, it also notes that the dispatchable synchronous generation provided by sources such as hydrogen-capable modern gas generation units will continue to serve an important role in the overall generation resource mix. The commenter states that by providing utilities with the option to make commitments to limit the RUL of units to no later than December 31, 2030, and providing a more flexible state emissions budget-setting approach with respect to such units, utilities would be able to consider all possible alternatives for replacement generation capacity. According to the commenter, this approach would achieve long-term and sustainable reductions in NO_X emissions through investment in new zero- or low-emitting generation resources. The commenter adds that these resources would be expected to remain in-service for decades to come, whereas NO_X pollution control retrofits on aging generation resources may remain in-service for only a handful of years. The commenter also states that the retirement of legacy generation assets for which SCR retrofits are economically infeasible could also necessitate transmission system upgrades, which can take five to seven years to plan, develop, and implement. The commenter believes the proposed flexibility with respect to units which make appropriate commitments to limit their RUL to no later than December 31, 2030, seven years after the anticipated issuance of a final FIP in 2023, aligns well with this expected time to execute any necessary transmission system upgrades.

Response:

See Preamble Section V.B.1.e for a response to comment regarding book life assumptions for SCR retrofit representative cost. See preamble Section VI.B.1.d for response to comment regarding SCR retrofit assumptions for state budgets and corresponding changes in the final rule regarding implementation and daily backstop rate start dates. The EPA made changes in the final rule that accommodate a longer time frame for reductions related to SCR retrofit at the state level. It also extended the start date for the daily backstop rate for units with new SCR retrofits. Both of these changes provide additional time and flexibility to accommodate the concerns expressed by commenter balanced against the EPA's statutory responsibility regarding elimination of significant contribution, as discussed in Section VI.A of the preamble.

10.5.2 Compliance / Deadlines

Comments:

Commenter (0288) comments are narrowly focused on one issue in the proposed rule—the feasibility of EPA's modeled NO_X reductions and implementation of control devices for the Company's East River Generating Station Unit 60 ("East River Unit 60") in 2026. The commenter notes that they own and operate East River Unit 60, which is a Babcock and Wilcox RB-81 superheat very large boiler with opposed wall firing. According to the commenter, the unit can fire natural gas or liquid fuel to cogenerate steam and electricity. The commenter notes that combustion controls optimize emissions reductions through continuous excess air control, low NO_X burners, and separated over-fire air. The unit is located on a space-constrained site in lower Manhattan (between E. 14th and E. 15th Streets and the FDR Drive and Avenue C) and shares the site with three other units (not including the South Steam Station which is on the opposite side of E. 14th Street) that generate electricity and steam for the Company's district steam system. The commenter discusses Appendix A, noting that the EPA states that East River Unit 60's 2021 NO_X emissions were 247 tons, with a pre-SCR retrofit NO_X emissions rate of 0.139 lb/mmBtu, and the Agency further asserts that retrofitting East River Unit 60 with an SCR could reduce annual NO_X emissions to 54 tpy, or a post-SCR retrofit NO_X emissions rate of 0.030 lb/mmBtu. Retrofitting East River Unit 60 with a SCR would be impracticable due to cost constraints based on facility-specific design issues. While developing its NO_X Reasonably Available Control Technology ("RACT") Plan, submitted to the DEC on December 29, 2011, pursuant to 6 New York Code of Rules and Regulations Part 227-2, commenter (0288) conducted a NO_X control technology assessment for its steam and electric generating units. At that time, although not included in the Company's final NO_X RACT Plan, an engineering analysis reviewed the potential to retrofit other very large boilers at a similar space-constrained location in the system (boilers 120-122 at the Company's 74th Street Station) with an SCR. The analysis concluded that doing so would require reworking of various plant infrastructure, including new forced draft and induced draft fans, and was likely to cost over $50 million. The commenter asserts that installation of an SCR at East River Unit 60 would be significantly more involved, requiring unique design elements, reinforcement of structural features (to mount the SCR unit on the roof, its only possible location due to the aforementioned space constraints), extensive reworking of the plant ductwork, and the installation of new induced draft fans and switchgear. Thus, during the 2011 NO_X RACT assessment, a detailed cost analysis of the installation of SCR at East River Unit 60 was not even conducted since it was expected to be substantially pricier than the 74th Street estimate. Therefore, while EPA's modeling assumptions appear to suggest that SCR installations can control NO_X emissions for $15,600 per ton, the commenter estimates that an SCR at East River Unit 60 would result in NO_X control costs substantially higher than that. For these reasons, the commenter requests that when finalizing the proposed rule, the EPA rerun the modeling effort for New York State without including the 193 (247 minus 54) ton reduction attributable to East River 60 Unit 60 in Appendix A and revise the New York State illustrative and/or final emissions budgets for the 2026 control period accordingly.

Commenter (0264) strongly advocates that the EPA select the less stringent alternative to the rule, providing additional time for control technology retrofits. The commenter claims that the proposed 2025 control period for installation and operation of state-of-the art emissions controls is simply unrealistic given the time required for design, engineering, construction and regulatory approvals for major capital investment projects such as an SCR retrofit. According to the commenter, the 2028 deadline proposed in the less stringent alternative is more realistic and is consistent with timelines under other federal regulations. The commenter concludes that the EPA's proposal for reducing interstate ozone transport from electric generators and industrial sources adopts unrealistic deadlines and overly-aggressive emissions control retrofit assumptions. The commenter strongly believes that greater compliance flexibility, and smaller adverse job impacts could be achieved by an incremental approach to pollution control upgrades, and adds that additional time for retrofits (such as the deadlines in the less stringent alternative to the rule) would enhance the feasibility of control installations while reducing the numbers of premature plant closures and related job losses.

Commenters (0290, 0317, 0372, 0396, 0409, 0499, 0511, 0519, 0539) disagree with the EPA's assumption (as stated in the proposed FIP) that it would require 36 months (three years) to complete new SCR installations at existing units. Commenters (0396, 0409, 0519, 0539) remind that in the past EPA has allocated anywhere between two and four years retrofit a single EGU with a new SCR, in response to unit-specific challenges, and also note (0519, 0539) a similar approach was described in the EPA's EGU NO_X Mitigation Strategies Proposed Rule TSD. Commenter (0290) agrees, based on four years of experience totaling over 55 design projects, that some SCR projects may be completed within a 36-month timeframe; however, the commenter underscore that not assumption should not be universally applied to all projects. The commenter states their belief that 32,000 MW of post-combustion SCR controls could not be designed, specified, bid, permitted, fabricated, installed and commissioned within the 36-month timeframe, because, for example, the engineering and design phase of a retrofit SCR project on a large coal-fired steam electric generating unit, including studies, equipment design, equipment specification preparation, and bid evaluation and award typically takes 18 months depending on the complexity of the project, compared to the 4 months that were assumed in the proposed FIP. Additionally, the commenter believes that the 36-month timeframe is an unrealistic amount of time for these activities as the bid period alone for the control system supplier to provide a firm priced proposal takes between 2-3 months. The commenter continues to briefly note differences in time needed verse time allotted in the proposal rule for the remaining steps/phases – *e.g.,* Vendor engineering, fabrication, and delivery of the equipment typically requires approximately 16 months and Installation of equipment can take approximately 18 months. The commenter also discusses the 18-month SCR installation project (for Unit 2) at the Xcel Energy's Hayden plant, as an example. Commenter (0317) layouts the proposed FIP installation schedule, and claims (based on the anticipated effective date of April 1, 2023, and assuming design commence at that point) the earliest date replacement power (due to the retirement of units) might be available would-be April 2027, but more likely April 2029. To illustrate, the commenter recalls the nearly five years (4.5 years) for SCR retrofit on Unit 5, located at the Wisconsin Power and Light, Edgewater Generating Station. The commenter concludes that EGUs will close/retire without replacement generation unless there is more flexibility in proposed state emissions budgets. Commenter (0499) questions EPA's decision/proposal to couple the timing assumptions for SCRs and SNCRs, despite noting that the Agency estimates that SNCRs may be installed within a 16-month timeframe. At least one commenter (0519) insists that a 36-month timeframe does not rationally account for unit-specific feasibility challenges or fleet-wide reliability and scheduling concerns, based on the broad applicability of EPA's SCR requirement.

Commenter (0372) worries that the financial impacts on states, the utility sector, end users, small businesses, EGUs and non-EGUs will be momentous; resulting in early retirements, stranded assets, and replacement generation will burden the American economy. The commenter notes that SCR technology installation projects alone are projected to cost $24,340 per NO_X ton removed and are expected to escalate to approximately $50,000 per ton; making investing in the proposed technologies even less appealing.

Commenters (0372, 0541) asks that the EPA consider time needed for financing the installation of SCRs; arguing that cooperatives face significantly longer time frames to conduct major outage projects than investor-owned utilities and because of their nonprofit status are more sensitive to rate increases. The commenters note that they (along with other cooperatives) make use of federal lending through the United States Department of Agriculture's RUS; which offers financing through a multi-step process. The commenters provide a brief overview of the muti-step process, first noting that a Work Plan must first be prepared (and later approved by RUS) that includes, for example, project justification for the project dollars to be spent. The commenters point out that RUS financing requires compliance with the National Environmental Policy Act (NEPA); adding additional time to a project, and the U.S. Department of Agriculture, who regulates actions financed by RUS, requires an environmental review (as set forth by NEPA). According to the commenter (0372), the environmental review process and timelines depend upon the scope of the project and ultimately what project documents RUS will request that the cooperative submit; however, the commenter expects that a large control device project likely will trigger an EA.

Commenter (0387) briefly describes the requirements for SCR installation as noted in the proposed FIP and states their belief that it is not equitable nor realistic to coercively mandate proposed SCR requirements against an industry, especially when they are faced with state and federal permitting requirements and costs, tight construction timeline constraints, and supply-chain issues – the end result will be mass premature retirement of coal- and gas-fired units not currently retrofitted with SCRs.

Commenter (0396) suggests that the EPA proposed FIP proposes overly aggressive control determinations and unrealistic cost-effectiveness and timing assumptions that threaten to impose more control requirements faster than the industry and the current grid system can sustain. It is implied that the commenter disagrees with EPA's assumptions that coal-fired

EGUs greater than 100 MW in capacity, as well as many gas-steam EGUs, would be able to install SCRs by 2026. Given the current economics and global events, the commenter believes that it is unlikely that many of those SCR installations will be materialized – *e.g.*, coal-fired EGUs will be left with few choices on how to comply—curtail operations, purchase allowances, or retire. The commenter concludes that curtailment of operations would likely be too costly and many of these units will simply be retired (as much as 27,300 MW of coal-fired units may retire by 2030 within MISO alone) between 2026 and 2028.

The commenter (0396) disagrees with EPA's rational that they have authority under the CAA to propose, what the commenter believes to be an unrealistic implementation timeline. The commenter notes that the D.C. Circuit has made clear that circumstances may justify more time. While the commenter agrees that SCRs cannot be installed by 2023, they ask EPA to recognize that the number of SCRs it assumes are needed cannot be installed by 2026 either. Additionally, the commenter also asks EPA to recognize that the first attainment deadline is too soon to expect sources to install combustion controls. The commenter recognizes that although combustion controls can certainly be installed more quickly than SCR, the Proposal still does not allow enough time for the work to be done, even if the rule is finalized by January 2023. The commenter reintegrates that a few months is not enough time to complete all of the stages of a combustion control project – including bid preparation and evaluation, engineering, fabrication, shipping of equipment, installation, and commissioning. The commenter requests that the EPA recognize that deadline is not possible to the extent it requires any new control installations, whether combustion or post-combustion controls, and should alter its state budget assumptions accordingly.

Commenters (0398, 0499) strongly disagree with EPA's assumptions that SCR is universally cost-effective and can be installed before May 2026, considering the proposal will likely not be finalized until early 2023. Foremost, the commenter (0398) questions the rationale for the proposed installation date (before May 2026) if the SCR-forcing back-stop" limit EPA has proposed will not become effective until the 2027 ozone season for units without an existing SCR; adding that this approach taken by the EPA would dramatically reduce state budgets beginning in the 2026 ozone season to reflect its assumption that SCR can be installed before May 2026. The commenter notes the number of expected SCR installations for several states – *e.g.*, or the state of Louisiana, 11 SCRs are expected to be installed within the given three-year period, while Texas, Oklahoma, and Arkansas, for instance, are assumed to install 31, 14, and 5 SCRs, respectively, and maintains that installing multiple SCRs under such a condense timeframe is challenging. According to the commenter the estimated for SCR installation should be closer to five years, given the current market conditions and site-specific considerations relevant to its EGUs, and based on evaluations of feasibility, costs and other control measures, as well as an assessment of EPA's four-factor analyses for the Regional Haze Program. Commenter (0499) specified the following additional reasons why proposed timeframes are unrealistic and the control costs are grossly inaccurate: (1) the installation of complex emissions control technology may take much longer than EPA has estimated; (2) EPA failed to account for current world events that are affecting the availability of materials and labor and that are unlikely to be fully resolved by the time a final FIP is promulgated or even for several years thereafter; (3) EPA is relying on outdated analyses to justify control timing estimates; and (4) EPA is basing its cost-effectiveness assumption for new SCRs on a 15-year amortization period, even though many units are likely retire between 2026 and 2032.

Commenter (0431) disagrees with EPA's assumption that all coal-fired units greater than 100 MW that do not currently have SCR technology installed will install such technology prior to the 2026 ozone season. First, the commenter believes that owners of units, with few years remaining of coal-fired operation, will opt not to invest in expensive control devices such as SCR, as it is simply not cost-effective. As an example, the commenter states that in Arkansas, there are four large EGUs that have federally enforceable dates to cease to use coal that will occur before the end of 2030. Second, the commenter believes that the proposed rule fails to consider the remaining useful life of the EGUs, and construction delays associated with the COVID19 pandemic, expert labor shortages, and global/domestic supply chain issues and events (Ukraine war).

Commenter (0506) supports a 21-month deadline to install/retrofit SCR on units, and questions EPA's rationale for selecting a 36-month deadline – *i.e.*, that "some" of the assumed SCR retrofit potential occurs at plants with multiple units, and rejecting the Agency's own analysis that found that 21 months is adequate time for planning, engineering, installation, and startup. The commenter states that the report on which EPA relies on for their estimate (36 months) states that the expected lead time for the installation of one SCR is not three years but 21 months inclusive "of total effort for planning, engineering, installation, and startup;" adding that shorter timeframes have also been reported. The commenter concludes, based on EPA's own acknowledgement that a 21-month timeframe to install/retrofit SCR is achievable, and in light of the mandates of New York and Wisconsin vs EPA [781 F. App'x 4 (D.C. Cir. 2019)], the EPA should rely on the installation timeline of 21 months. Additionally, the commenter argues that the projected capacity of retrofits is significantly less than the retrofits accomplished in a single year almost 20 years ago, 32 GW of SCR retrofits compared to 41.7 GW (after SCRs successfully went online to comply with the NO_X SIP Call), and therefore, a 21-month timeframe is reasonable. According to the commenter, new SCR controls could be installed in time for the 2025 ozone season without posing reliability concerns, if the rule is finalized before May 2023. The commenters maintains that units would be offline for only a portion of the time it takes to install the control, not for the entire 21 months. The commenter reminds that a planned outage requires permission from an ISO/RTO (in regions where such organizations manage the bulk power system) to protect the system against risks to reliability, which allows ISO/RTO's the ability to stagger the outages across the shoulder seasons between now and May 1, 2025. The commenter argues that plants retrofitting units/installing SCRs could take them offline to at the same time (during non-peak seasons) without posing reliability concerns. The commenter suggests that this timing is likely preferable for those plants because market prices are generally lower during the shoulder seasons. The commenter concludes that timing reliability considerations should not pose an obstacle to fleet-wide retrofit of SCR by the 2025 ozone season and recommend that the EPA not rely on the "SCR and SNCR Typical Schedules" reports, as described in the EGU NO_X Mitigation Strategies Proposed Rule TSD document, whose underlying data, assumptions and author(s) are unknown.

In a similar comment, commenter (0506) recognizes that the EPA has determined that SNCR technology can be installed in as little as 16 months, yet selected to have state budgets not reflect SNCR retrofits until the 2026 ozone season. The commenter believes that if EPA proposes a 21-month timeframe, instead of the current 36-month than any concerns EPA may have about precluding smaller units from installing SCR instead of SNCR because of the longer lead time required for SCR retrofits, are eliminated.

Commenter (0511) points to the four years it took to install a SCR at the Harrison location as proof that additional time is needed to install SCR technology into the existing footprint of the plant. The commenter argues that the entire process can take up to 72 months when considering all the internal and regulatory requirements/approvals. To further illustrate, commenter (0539) reminds that environmental permitting is required in the State of Minnesota prior to beginning construction, which, according to the commenter can take 18-24 months or longer, leaving only 12 months for construction and commissioning under the proposed FIP's 36-month presumption. The commenter explains that for states, like Minnesota, which have shortened construction seasons, meeting the 36-month timeframe would be extremely challenging timeframe to complete a significant retrofit on a baseload coal-fired unit. Instead, the commenter recommends a 4-year timeframe (or 48 months) – a timeframe, according to the commenter, has been supported by the EPA in the past (for region-wide actions). To further illustrate the unattainableness of the timeframe, commenters (0372, 0385, 0409) recall the time allotted for the installations of SCRs during 2003, which, according to the commenter, was the largest number of installed SCR ever done (more than 35000 MW) and reminds that the proposed rule (in capacity) exceeds the amount done in 2003, and at a more condense timeframe. The commenters insist that it is not logistically possible due to limited boilermakers to accomplish this volume of installations in the time EPA provides in the Proposed Rule. The commenters add that based on the past retrofit data, roughly 40 to 45 months is needed, which, according to the commenter, is likely not achievable with today's inadequate resources. The commenters recommend that the EPA allot an additional 18-months lead time and asks that the EPA revise the SCR installation time frames to provide 58 months (40 months plus 18 months for RUS financing); meaning, no installation prior to 2028 ozone season. Commenter (0372) also provides an expected schedule for a typical SCR retrofit and discusses a recently taken environmental compliance project with RUS funding for CCR Rule compliance; noting that a 4-year timeframe is more appropriate, based on findings.

Commenter (0524) requests that for units in mixed configuration that exhaust to a common stack, compliance with the backstop limits, should be deferred to 2027. Otherwise, according to the commenter, requiring the SCR-equipped units in such a mixed configuration to demonstrate compliance by 2024 would lead to the use of inaccurate data for gauging compliance, since emissions would be overstated for the SCR-equipped units. The commenter further claims that deferring compliance until 2027 for such units is especially important since exceedance of the backstop limits are subject to CAA enforcement. (Note: This is of particular interest for the commenter [TVA] because the TVA Shawnee Fossil Plant in western Kentucky currently has one common stack exhausting two SCR controlled units and 3 uncontrolled units.)

According to the commenter (0541) the extended timeframe would be needed to address various factors, including pre-construction permitting, bidding, engineering, fabrication and shipping of equipment, preconstruction retrofitting, installation, and commissioning.

Commenter (0531) worries that the proposed FIP, as written, will result in the simultaneous installation of multiple SCRs through the country, creating a strain on control technology resources, making it impossible for states and regulated entities to comply by 2026. The commenter implies, given current economic market (sourcing delays, material availability and potential labor availability), that the Agency's proposed emissions rate (0.08 lb/mmBtu and 0.05 lb/mmBtu) for state budgets is unrealistic within the three years allotted to meet the state budgets. The commenter states that based on their preliminary project schedule, they believe regulated entities would need at least three years, from project commencement to having the first SCR begin the commissioning process, to comply. According to the commenter, availability, along with a very congested site with limitations on placing construction equipment and working around operating units, will make it very difficult to work on multiple SCRs simultaneously. The commenter adds that in addition to the need to minimize multiple tie-in outages at the same time, a staggered construction schedule appears to be the most likely scenario which would place the subsequent SCRs in-service after the above projected date of January 2026.

Commenter (0520) opposes any regulatory requirement to install SCR on the specific unit – Hunter Unit 2, and claims that the EPA's required timeline of 36 months (three years) to install SCR is patently unreasonable and not feasible. In addition to owning interests in or directly operating power plants and other sources of electrical power, the commenter says that they regularly purchase power off the grid, and are, therefore, sensitive to market and regulatory forces that impact electricity affordability and reliability. The commenter makes the point that Western power markets are already being tested by retiring power generation facilities and premature closures caused by the Proposed Rule will only exacerbate the power markets, increase wholesale prices, and result in increased costs to end-use customers. More specifically, the commenter speaks to their ownership interest (roughly 14.6percent) in Hunter Unit 2 and imply that the force installation of SCR on the unit would be costly – costs that they infer would be shifted to customers.

Commenters (0541, 0546) remind that the EPA has previously asserted in the Regional Haze rule that five years is "as expeditiously as practicable" to install new SCRs; thus, the commenter questions EPA's decision to shorten the timeframe to three years, especially in light of current events (*i.e.,* labor shortages and supply chain issues amid a global pandemic and heightened international tension) is arbitrary and capricious. The commenters maintain that the three years allotted for the installation of a SCR system on an EGU is very aggressive schedule and one which fails to account for all of the variables inherent in execution of such a retrofit (permitting, engineering, procurement, construction, and testing), and according to the commenter (0546) the 3-year period would significantly limit the options available to a utility to plan, develop, and place into service alternative generation to allow for the replacement of legacy generation units for which an SCR retrofit is simply uneconomic.

Commenter (0539) claims that it would take them roughly four years to install a SCR on their Boswell Unit 4; adding however, that the process could not commence until a final rule has been issued.

Commenter (0547) disagrees with EPA's assumption (as stated in the proposed FIP) that it would require roughly "21 months of total effort for planning, engineering, installation, and startup". Commenter (0547) claims, based on their experiences, that the time needed (from commencement to operation) would require a significant longer period than allotted under the proposed rule, and references the installation of an SCR (which took nearly five years) on Unit 1, at Laramie River Station, as an example. The commenter asserts that the proposed timeframe is largely underestimated; adding that the EPA, in the past, has acknowledges that variations among sites and regulatory programs alone has caused the amount of time to retrofit a single EGU with new SCR to be anywhere between two and four years [87 FR 20080]. Furthermore, the commenter argues that the EPA does not acknowledge that each phase (*e.g.*, engineering review, construction permit, control technology installation, and obtaining an operating permit) is reliant on the previous phase for continuous forward progress. Recognizing that timing is not a one-size-fits-all approach, and based on their own prior experience, the commenter asserts that implementation by 2026 is not achievable. The commenter disagrees with the timeframe identified for each phase; arguing instead that the engineering phase takes roughly 6 months that includes a 3 to 4 month bidding process (instead of the noted 4 months), the construction permit phase would take more than the allocated 9 months due to a lengthy process likely to involve delays due to states having to review multiple permits mutinously, the control installation phase (which includes compliance testing of the control technology) would take at least two years from state to finish (instead of the noted 17 months). The commenter notes, that under the control installation phase, the EPA's timeframe fails to account for the scheduling of outages, preparing to utilize planned outages, and working with suppliers and other facility owners to ensure resource availability – boiler typically must be shut down for this period.

Response:

See Section V and VI.A and VI.B of the preamble and the EGU NOx Mitigation Strategies Final Rule TSD for responses to comments regarding determination of "significant contribution" as to EGUs, SCR installation timing, and the overall framework for EGU emissions-reduction implementation. The EPA has made changes in this final rule that provide more time and flexibility to meet state-level and unit-level emissions performance expectations associated with SCR retrofit.

In regard to comment on SCR installation at East River 60 being logistically challenging and more costly, first we note that our representative cost numbers used in the Step 3 analysis already reflect a range of costs that different facilities may face, with some facing lower costs and others facing higher costs. Thus, the commenter has not established a basis for why their facility should be excluded from the determination of "significant contribution" that would otherwise be applicable to units of its size and profile. Second, compliance is feasible for this source. It is acknowledged that SCR could be installed; the commenter's complaint is simply that it would be more challenging than for other facilities. However, other methods of compliance are also available within the context of an emission trading program. The EPA notes the rule applies no daily backstop rate to this unit and there is no technology mandate or unit-level rate requirement reflecting a technology being in place. The state budgets are calculated using uniform assumptions that reflect SCR retrofit at units of this size and profile, but the trading program implementation allows some sources to exceed this expectation and others to use alternative compliance mechanisms (such as allowance purchase). The EPA also notes that the emissions rate for this unit has ranged from 0.10 lb/mmbtu to 0.14 lb/mmBtu over the past five years, indicating some ability for the source to reduce emissions from measures already available.

10.5.3 Capital Recovery / Investment – Remaining Useful Life Beyond 2026

Comments:

Commenter (0272) states in Appendix A Proposed Rule State Emissions Budget Calculations and Engineering Analytics, the EPA assumes our E.F. Barrett Unit 1 and Northport Unit 4 would install SCRs; however, according to the commenter, this assumption is not likely to occur for several reasons. First, the commenter notes that with New York's goal of transitioning to renewable energy by 2040, it is anticipated that the future operation of this unit would decrease significantly, making the investment in SCR uneconomic. Furthermore, the Barrett facility is strategically located within the Long Island electric system and is currently being evaluated for repurposing for renewable energy technologies. Future renewable projects would use the vacant land currently at the site preventing the installation of a SCR.

In a similar comment, commenter (0272) states that over ten years ago they evaluated installing an SCR on one or more of the units at its Northport generating facility – a facility consisting of four identical steam electric boilers, fired primarily on natural gas, with #6 residual fuel oil as a back-up. A conceptual design was developed; however, according to the commenter the space was tight. Additionally, it was not possible to determine which unit would provide the most emissions reduction opportunities since units are dispatched based on the requirements of the Transmission Owner and operation among the units varies. Instead, the commenter notes that a significant investment was made to install Separated Over Fired Air combustion controls for all four units. That achieved an approximate 30-40percent reduction in NO_X emissions. The commenter adds that operators at the facility are aware of regulatory NO_X limitations and the unit typically operates at 50percent or less of the New York State RACT limit of 0.15 pounds NO_X/mmbtu. With New York's transition to renewable energy by 2040, the commenter states that it is anticipated that the utilization of the Northport units would decrease significantly, similar to Barret Unit 1. For these reasons, the commenter believes it would be uneconomic to invest in additional emissions controls at this facility and recommends that the EPA revise their modeling assumptions to exclude additional emissions reductions from these two units.

Commenter (0351) believes that the EPA's analysis of the cost and timing of NO_X control installation, as applied specifically to units with five years or less remaining life (*e.g.,* Serco 3 Unit – which is committed to be shut down at the end of 2030) is arbitrary and capricious. The commenter states that the EPA's cost-effectiveness analyses and implementation schedules, which form the underpinnings of its conclusions in Steps 3 and 4 of the Proposed Rule's four-step framework, simply cannot withstand scrutiny when applied to Sherco 3. The commenter explains that assumptions made during the steps (*e.g.,* assuming the "book life" is 15 years for all SCR on EGUs), while they may be reasonable for SCR installations at many EGUs, a 15- to

20-year cost-recovery timeline is not reasonable for units like Sherco Unit 3, that are expected to retire shortly after the proposed FIP is finalizing. The commenter further clarifies that the $11,000 per ton threshold for 2026 is not representative of Sherco 3 (and other units with five years or less remaining life) and insists that the actual cost to retrofit this and other units like it would be roughly $41,000 per ton; resulting in SCR controls that are cost-inefficient. Similarly, the commenter claims that the per-ton cost calculations for Sherco 3 ($1,800 per ton) are orders of magnitude greater than what the EPA has found to be a reasonable cost threshold in prior ozone transport rulemakings.

In a similar comment, commenter (0351) announces that one of their EGUs (Sherco 3) is scheduled to be decommissioned in 2030 pursuant to an enforceable consent decree entered by the commenter and the MPCA. Under the proposed FIP, this unit would be required to install selective Catalytic Reduction (SCR) pollution control technology on the Unit in 2026, which according to the commenter, comes at enormous cost and without adequate opportunity to recoup those costs, a mere four years before its scheduled decommissioning. The commenter explains that they would, alternatively, be forced to operate the Unit at a maximum of only 31percent of its normal operating capacity (during the ozone season) for its remaining life to comply with the Proposed Rule's emissions limits. The commenter asserts that this would result in substantial replacement power costs that would have to be recovered, partly through higher retail rates. The commenter clarifies further noting that the marginal costs of installing SCR on the Unit, given the Unit's short remaining life, far exceed those costs the EPA assumes in the Proposed Rule, and in this respect requiring the commenter to comply with the Proposed Rule's emissions limits would be arbitrary, capricious, and contrary to law. The commenter adds that the alternative of curtailment of operation is also inordinately costly and would have dire consequences on owner's ability to service its customers, and for the electric grid itself. The commenter asks that the EPA include in its final Rule one or more of the following options applicable to units with enforceable decommissioning commitments:

1. excluding from the final Rule's modeling (and resulting limitations on state emissions) any EGU (like the Unit) that will be decommissioned pursuant to an enforceable commitment where a state is only "linked" through modeling to downwind interference with maintenance areas; concurrently, removing such affected units from any other source-specific limitations proposed in the final Rule; and, if justified on the basis of the revised modeling, removing any state, like Minnesota, from the proposed FIP if that state would no longer significantly interfere with downwind maintenance areas;
2. allowing additional allocations for units that will be decommissioned within the time period for downwind states to come into compliance with the NAAQS—the outside date being 2032 for severe non-attainment areas having an attainment deadline in August 2033;
3. providing emissions limitation exclusions under the rule for any EGU with an enforceable decommissioning date earlier than 2032; or
4. adjusting the Proposed Rule's 2028 decommissioning cutoff date for exemption from the backstop daily rate contained in the Proposed Rule to allow this exemption to apply to units with an enforceable decommissioning date before 2032, or on a case-by-case basis.

Response:

See Sections V.B, VI.A, and VI.B for responses to comments on control timing and budget implementation assumptions. The role of cost as a factor in the 4-step interstate transport framework is primarily addressed in Sections III.B and V of the preamble and in Section 4 of this document.

Comment:

Commenter (0351) suggests that the Proposed Rule's requirement for SCR installation or such a significant reduction in operation of EGUs to meet the Proposed Rule's backstop limit is unreasonable for units with enforceable shutdown dates because EPA's air quality analysis for maintenance areas does not support such extreme reductions; even assuming if costs and timing to install SCR on Units (Sherco 3) were reasonable.

Response:

EPA has no assumed SCR retrofit for Sherco 3 in this final rule as Minnesota is not linked in 2026 in the final air quality modeling.

Comments:

Commenter (0409) also claims that existing infrastructure shortfalls coupled with the diminishment of engineering and construction availability and expertise over the past ten years, only increases the need for reasonable/realistic estimates of required SCR installation times. Additionally, the commenter claims that the EPA significantly underestimates SCR costs; arguing that selected SCR technology drastically exceeds the cost effectiveness ranges in the proposal –negating the technology as a reasonable choice in 2026, or subsequent years. The commenter asks that for units retiring or converting to natural gas by 2030 (or by reasonable thereafter) not be required to install any additional technology beyond optimizing existing installed technologies. The commenter explains that the daily NO_X limit of 0.14 lbs/mmBtu should not apply, and state budgets should reflect these adjustments beginning in 2026 based on emissions limitations associated with existing optimized installed controls.

Commenter (0539) claims that the EPA's 15-year amortization for SCR retrofits assumption does not consider current supply chain/workforce constraints, and underestimates project timelines. The commenter briefly discusses one of their units, Boswell Unit 4, which is projected to be coal free by 2035, and the commenter's only unit greater than 100 megawatts currently without an SCR. According to the commenter, the remaining coal-fired life of this unit is less than 13 years, combined with the effectiveness of its existing NO_X controls, would result in an unfavorable incremental cost-effectiveness justification, which makes economic regulatory of such an investment approval highly uncertain. The commenter predicts it would take roughly four years to install a SCR on this unit, with a 2027 completion date expected, leaving only eight years (half the assumed time of 15-years) until it is committed to be coal-free. The commenter urges the EPA to reduce its 15-year SCR payback assumption for units, like Boswell Unit 4. At minimum, the commenter recommends that the EPA recalculate the cost effectiveness of its proposed FIP given existing coal unit retirement dates (as submitted in the commenter's IRP).

Commenter (0541) reminds that the EPA used a 15-year capital recovery factor for costs of NO_X controls; however, the commenter highlights that many units that are modeled to install controls have plans to retire before 2041. The commenter argues that, for these units, a 15-year capital recovery factor is inappropriate and the cost of installing control devices (on these units) would be significantly higher. The commenter recommends that the EPA allow sources to self-report retirement dates, determine an appropriate capital recovery factor for individual sources, and re-evaluate costs of additional NO_X controls based on the remaining life of the source. More specifically, the commenter (0541) recommends that the EPA revise the timeframe allowed to retrofit SCRs to five years to match previous regulatory actions, allow cooperatives additional time to complete the NEPA process, re-evaluate costs of NO_X controls based on the remaining life of sources, and recalculate state budgets accordingly.

Commenter (0546) suggests that investing in costly SCR retrofits on units that, on average, will be more than 52 years old in 2026 is an unsupported and unreasonable assumption for EPA to make. The commenter instead recommends allowing an alternative and more measured approach to adjusting future-year state budgets that offers some flexibility with respect to units with a limited RUL would allow the commenter (and other similarly-situated utilities) sufficient time to consider all possible options for development of replacement generation capacity.

Response:

See preamble Section V.B and VI.B for discussion of multiple changes in the final rule to accommodate EGU retirement plans and power sector transition.

10.5.4 Site-Specific Challenges

Comments:

Commenter (0290) argues that the proposed timeframe of 36-months, fails to consider restricted site arrangements and significant site congestion that often require more stick-built structures and less modular construction; increasing the overall construction timeline. To illustrate, the commenter describes the nearly 5-year (4.5 years) SCR installation at Basin Electric Laramie River Unit 1 – a stark difference from the assumed 16-month. The commenter disagrees with EPA's assumption that permitting activities occur concurrently; noting that many facility owners/operators require issuance of the air permit prior to vendor award, as significant costs are incurred upon award. The commenter contends that even if the owner/operator is willing to incur expenses associated with award of the project and permitting is conducted concurrent with detail engineering and fabrication of the equipment, a permit must be obtained prior to commencing installation of the equipment. Based on past project experience, the commenter acknowledges that some projects may contribute to the formation of/an increase in emissions of $PM_{2.5}$; adding that PSD permitting which includes evaluation of Best Available Control Technologies (BACT), air quality impact modeling, and public review/comment, can take from 12 to 18 months from application submittal to issuance of a final permit.

Commenter (0370) requests that the EPA consider additional time in which generator owners may deal with the logistical challenges of installing SCR and related equipment or building the necessary replacement generation. In lieu of additional time, the commenter also requests that the EPA consider some means of providing a reliability "safety valve" that will allow a generator to operate beyond the constraints imposed by the Proposed Rule if an RTO identifies a reliability-based need for that generator.

Commenter (0396) questions why EPA selected not to consider site-specific considerations when establishing state budgets and compliance deadlines, especially since the EPA has recognized in the Proposal that site-specific considerations are relevant in evaluating the time needed to install SCR.

Commenter (0396) disagrees with EPA's assumption that the trading market for allowances will provide the compliance flexibility needed by some facilities due to site-specific considerations.

According to the commenter, the market for allowances is highly unlikely to be robust enough to allow all units with site-specific constraints to comply via procuring allowances.

Commenter (0511) state their belief that the requirement for the additional SCR installations should be eliminated; at minimum recommending that the EPA extends the deadline for SCR installations.

The commenter believes that SCRs are not needed on the Fort Martin EGUs to achieve ozone NAAQS attainment in downwind states. The commenter notes that there will be difficulties in achieving the proposed deadline for SCR retrofitting and is concerned that there are no flexibility procedures proposed. The commenter explains that non-retrofitted units often have more complex installation requirements due to unit/facility layout and other unit specific features. According to the commenter, this would require a longer duration for engineering design, construction, and incorporation into the outage cycle scheduling.

Commenter (0519) states that it took roughly four years to install a SCR at Oklahoma Gas and Electric's Horseshoe Facility due to difficulties associated with its unique physical configuration and the age of the unit. The commenter provides the following unit-specific activities that would need to be done to install a SCR at the Horseshoe Facility:

- Engaging an architect-engineer (AE) to prepare a conceptual design of the SCR: The AE would have to thoroughly review existing plant data and drawings and evaluate potential physical space limitations as well as possible relocation of existing systems.
- Preparing specifications for the SCR, as well as balance-of plant equipment, and conducting a bid evaluation, commercial negotiations and system award. Overall, the design, specification, and procurement process [are] estimated to take 10 months.
- Fabricating and Delivering Equipment: Once the SCR is awarded, addition.al time will be necessary for the equipment suppliers to fabricate and deliver the new equipment

- Preparing a detailed design: The AE will perform detail design of the system in parallel to the equipment fabrication. Detailed design includes general arrangements, P&ID's, isometric drawings, calculations, building modification drawings, foundation drawings, demolition drawings, electrical and controls modifications. The design/fabrication time to get the equipment on site is estimated to take 18 months.
- Installing the SCR: Sufficient time will be necessary to install the SCR as well as perform commissioning and startup. These construction activities are estimated to take 20 months to complete.

Commenter (0547) notes the location of Unit 1 at the Laramie River Station made installing SCR easier than other units (Units 2 and Unit 3) because Units 2 and 3 don't have considerable open space adjacent to them. The commenter clarifies that the open space allowed for easy field assembly of structural steel and SCR components, which resulted in the need for fewer crane lifts and less assembly at high elevations.

Response:

The EPA notes that Wyoming is not subject to this final action, which moots some of the SCR installation concerns raised by commenter. See Preamble Section VI.B for further discussion on the topics raised in these comments.

10.5.5 Assumptions Based on Outdated Data

Comments:

Commenter (0320) briefly describes the analysis performed by the EPA to determine requirements for controls on non-EGU boilers and claims that the analysis is heavily flawed – not based on quality inventory nor is it based on actual achievable and feasible control and NO_X reduction measurements, along with it underestimates costs of SCRs and fails to include dispersion modeling. The commenter asks that the EPA defer application of NO_X controls to industrial boilers until it determines they are actually necessary to achieve downwind attainment.

Commenter (0394) argues that the EPA's projection that state-of-the-art combustion control upgrades can be achieved by the start of the 2023 ozone is based on outdated information derived from a limited number of atypical retrofits. According to the commenter it will take roughly 22 months to retrofit combustion controls. The commenter maintains that the EPA therefore should not assume that emissions reductions can be achieved through installation of state-of-the-art combustion controls before the 2024 ozone season and should not assume that all installations could be achieved by that time. The commenter notes, according to American Public Power Association (APPA), it took 24-30 months to install combustion controls like low NO_X burners (in 2009) and overfired air and 40-60 months to install back-end emissions controls (in 2011).

Commenters (0372, 0409) maintain that NO_X combustion controls cannot be installed by the

2023 ozone season – in less than 12-months; adding that the EPA's assumptions are based on dated information (over ten years old). The commenters argue, based on a more robust Technical Report analysis, that NO_X combustion control projects can take up to an estimated 22 months to complete, with some reports stating upwards to 60 months. If project conception started immediately, the commenter (0409) does believe that most units could potentially deploy SCR controls for the 2025 ozone season; but that would be the earliest the Agency should expect retrofits to begin.

Response:

Implementation of state-of-the-art combustion controls as expressed in the state EGU emissions budgets begins with the start of the 2024 ozone-season. See sections V.B through V.C of the preamble for further discussion. In regard to the comments suggesting even more time beyond 2024 is needed for this technology, the EPA notes that the same technology timing assumptions were made in the CSAPR Update and Revised CSAPR Update rules. Due to the timing of the CSAPR Update final rule promulgation and the start of the next ozone-season, the state emissions budgets (reflecting this technology assumption) went into effect as of the 2017 ozone season, about six and half months after signature on the final CSAPR Update Rule for most states (with the exception of Arkansas). A review of historical emissions data and allowance prices indicate there was 100 percent compliance with the state budgets and allowance holding requirements in 2017 at a cost well under that suggested by the cost-effectiveness values used at Step 3 in that rule. This provides further empirical evidence that the EPA's timing and cost assumptions are reasonable and viable for this technology, as similar assumptions have been implemented in a similar fashion but on an even shorter time scale in the CSAPR Update.

Comments:

Commenter (0409) argues that the SCR installation timeline assumptions and the related emissions reductions incorporated into the 2026 allowance budget are not supported by empirical data on past SCR installations. The commenter claims that the earliest SCRs could be installed is for the 2027 ozone season, and in most cases electric cooperatives installations require National Environmental Policy Act (NEPA) review; extending installation timelines even further.

Commenter (0409) points out that electric cooperatives face significantly longer time frames to conduct major outage projects than investor-owned utilities and results that the EPA factor in additional time for electric cooperatives for financing via largest financier of cooperative capital projects, RUS – an arm of the federal government. The commenter provides a brief description regarding RUS financing – *e.g.*, it requires compliance with the NEPA, and stresses that these financing requirements add time to a project and its ability to comply with other federal/state regulations. The commenter reiterates that while other financing options may be available for certain types of projects, the interest rates are significantly higher, and as a not-for-profit organization, many electric cooperatives are disadvantaged. The commenter insists that the EPA factor in at least an additional 18 months on top of the projected time frames discussed herein to allow cooperatives to obtain financing for a large control device installation project such as an SCR or SNCR.

Response:

See Preamble Section V.B and VI.A-B for a discussion of changes that the EPA has made in the final rule that address the SCR installation timing assumptions and related trading program flexibilities.

10.5.6 Supply Chain and Other Installation Challenges

Comments:

Commenters (0271, 0327) argue that the proposed FIP does too much too fast; stating the proposed FIP would render moot the hundreds of millions of dollars that ratepayers have invested in enhanced NO_X controls, including enhanced combustion controls and Selective Non-Catalytic Reduction (SNCR) systems, and imposes a draconian edict that all plants install replacements to those systems – called Selective Catalytic Reduction (SCR) controls – in just three years from the start of the new program. The commenters insist that it is not possible to accomplish the monumental task of universal SCR installation by 2026, especially when considering state and federal permitting requirements, as well as construction time and supply-chain issues, electric utilities will not have time or funds to install these expensive controls and there will not be sufficient time to stage and stagger the planned outages necessary for such a massive construction project across the fleet; resulting in the mass premature retirement of coal and gas units not currently equipped with SCRs.

Commenter (0506) supports a 21-month timeframe to install/retrofit SCR on units and suggests that the EPA's assertion that there is sufficient skilled labor availability (particularly boilermakers) to install all of the SCR retrofits in the Proposed Rule, is supported.

Commenters (0290, 0351, 0354, 0370, 0396, 0511, 0519, 0539, 0547) assert that the EPA's proposed FIP fails to consider the effect of supply chain disruptions due to factors completely out of their control – the ongoing pandemic and impacts from inflation, the global market and other events (on the availability of labor and materials), to install new SCR or retrofit existing units; all of which are likely to constrain the ability of sources to conduct multiple construction projects (SCR installations/retrofits) in such a condensed timeframe and without jeopardizing the availability of reliable electricity. At least one commenter (0370) states their belief that such supply chain issues will be exacerbated, in terms of both availability and cost, by the tight timeframe contemplated by the Proposed Rule.

Commenter (0290) argues that the EPA's proposed 36-month completion timeline does not consider potential supply chain delays in equipment fabrication and delivery due to high demand, nor does it consider weather related delays due to high winds, storms, or extreme weather conditions. Additionally, the commenter points out the scheduled does not include potential delays due to unknown underground interferences which could result in re-work of the control system layout or construction delays.

Commenter (0290) recognize that there are also potential roadblocks and bottlenecks the market may see with large scale deployment of SCR's that could extend the proposed 36-month schedule further. According to the commenter, the lack of new coal generation and accelerated retirement of most of the coal fleet domestically has reduced the need for air quality control system retrofits and the need for skilled boilermakers; resulting in fewer companies in the market, generally lacking in resources and knowledge to complete these types of large-scale retrofit projects. The commenter does not agree with EPA's finding that there is sufficient skilled labor available to install the retrofit technologies based on IBB active membership (47,615 membership in 2021), particularly considering the likelihood that SCR installations/retrofits will occur at the same time. The commenter worries that the simultaneous installation/retrofit of SCR will result in competition for resources, labor, materials, etc., which will delay owner's ability to meeting the proposed deadline. The commenter cites Career Explorer which estimates 17,200 boilermakers in the United States and that over the next ten years, it is expected that the U.S. will need 8,000 more boilermakers. The commenter explains that the estimate is based on 1,500 additional boilermakers and the retirement of 6,500 existing boilermakers. The commenter also references the US Bureau of Labor Statistics and the Associated Builders and Contractors, who also predict that there will be a decrease in boilermaker employment in the upcoming years.

Commenter (0547) argue that impacts from the COVID-19 pandemic coupled with a saturated market, has affected the availability of labor. The commenter notes that SCR projects are likely to face internal market competition for the skilled labor – specifically boilermakers – needed to implement this control technology and agree with the Agency that these labor shortages are potential constraint to, the installation of a significant amount of emissions controls. The commenter stresses that fewer companies in the U.S. are offering emissions control services and cites the US Bureau of Labor Statistics which predicts a one percent decrease in boilermakers over the next ten years.

In a similar comment, commenter (0547) cites the Sargent & Lundy report, as additional support, which concludes that there will be anticipated labor shortages associated with the requirement to install approximately 32,000 MW of SCR retrofits; making it "unlikely that 32,000 MW's of SCR could be installed within a 3-year period."

Commenter (0351) asserts that past retrofits have taken upwards to four years to complete, a timeframe that if coupled with today's shortages in staff/labor, the increase workload that is expected as a result of the rule, and the lengthy permitting process, make it almost impossible for units to comply. The commenter also feels that the EPA's reliance on Wisconsin is misplaced as support for its determination as to what is an achievable deadline for SCR installation, because unlike that case, a fixed deadline has been set.

Commenter (0394) states their belief that the amount of time allotted to install SCR on the scale called for in the Proposed Rule is insufficient, partly due to inadequacies of resources – including equipment and labor, and partly due to the geographic area (of the units) assumed in the Proposed Rule. The commenter recommends, in an effort to avoid delays, to stagger installation over the course of several years; noting that the 2026 start date in simply unattainable event if engineering and procurement began when the proposed FIP was published. Additionally, the commenter notes that the proposed FIP fails to consider supply chain issues/disruptions, or the high demand for major power plant equipment, material, and construction. The commenter disagrees with EPA's assumption that that there will be sufficient workers and construction housing available across the regulated states to complete these SCR retrofit projects by the start of the 2026 ozone season; noting that public power utilities have expressed concerns over the lack of available construction workers and housing. The commenter request that the EPA consider allowing for an extension to install SCRs based on a showing of necessity, similar to EPA's proposal to offer non-EGUs a compliance extension to install SCRs.

Commenter (0396) states their belief that the EPA fails to consider the impact (on grid reliability) of a rule that would force installation of so many control devices in such a short period of time. The commenter explains that each of the units that the EPA assumes will install SCR in response to the Proposal would require a major "tie- in" outage of at between 45-90 days for the controls to be installed; which will need to occur at approximately the same time near the end of the three-year compliance window in the Proposal, possibly resulting in a severe shortage of generation just before and likely during the 2026 ozone season.

Commenter (0511) asserts that given the number of units EPA has identified for SCR retrofit, it is unlikely that there is sufficient capacity for equipment suppliers or qualified labor to meet the demand within the proposed 36-month timeframe. The commenter asks that the EPA extend the deadline for SCR installations /retrofit beyond the current deadlines. The commenter urges the EPA to consider allowing for more flexibility; arguing that a good-faith SCR retrofit/installation may miss a future deadline, due to issues outside of the EGUs' control.

Commenter (0519) disagrees with EPA's finding, regarding the availability of skilled labor under its proposed FIP, that "there are now more boilermakers available, ...the current number of boilermakers will provide sufficient labor availability." The commenter suggests that the analysis fails to consider supply chain issues that are likely to significantly impact retrofit timing across existing fleets – as explained further in the Sargent & Lundy analysis.

In a similar comment, commenter (0519) argues, in regard to SCR installation, that the EPA fails to account for additional timing constraints based on reliability concerns for EGU operations. The commenter explains that timeframe for installation of SCR equipment must be coordinated with the outage schedules to assure electric grid reliability. The commenter explains that these considerations prevent fleet operators from scheduling simultaneous retrofits that could shorten installation times, as these retrofits would require simultaneous outages that would significantly impact grid reliability. Specifically, the commenter notes that the EPA's assessment of fleetwide installation timing (three years) fails to account for:

- "[P]otential delays in equipment fabrication and delivery due to high demand;"
- "[W]eather related delays due to high winds, storms or extreme weather conditions;"
- "[P]otential delays due to unknown underground interferences which could result in rework of the control system layout or construction delays;" and

- Delays caused by environmental permitting activities that cannot occur concurrently with engineering, specification preparation, and vendor award.

Commenter (0539) cost estimates for the design, construction, and installation of additional controls are outdated and not reflective of current conditions – fails to include impacts from COVID and supply chain issues, all of which pose significant challenges to, for example, the construction of new assets. The commenter further argues that the proposed FIP estimates fail to reflect other factors utility and energy providers are expected to face on major construction activities, including labor shortages and competitiveness pressures within the building trades to provide labor levels to support major construction and installation activities.

Commenter (0362) expresses concerns that disruptions in the global supply chain (as a result of COVID and the Ukraine war) will hinder the ability to comply with the proposed three-year timeframe, and as a result, will force units to prematurely retire; ultimately impacting the grid reliability. The commenter states that they are already experiencing delays in receiving the necessary materials and auxiliary equipment/components (*e.g.*, fans and electronic components) that are critical to the operation of boilers. For instance, the commenter states that the lead time on what use to be an in stock-item, variable frequency drives (VFD), which that allow fan motors to operate more efficiently is over 52 weeks. The commenter cites a few other business articles, journals and reports (*e.g.*, Bloomberg) that reintegrate supply chain issues and concerns. The commenter recommends extending the compliance deadline to May 1st (of the year following promulgation of a final rule).

Commenters (0363, 0364) maintains that in the proposed FIP, the EPA does not address the current supply chain disruptions affecting the electric sector, and therefore, insist that the EPA's assertion that retrofitting could be accomplished within three years, may be reasonable under normal conditions; however, the electric sector supply chain is not operating under normal conditions. The commenters urge the EPA to reconsider the deadline for retrofits under current conditions or delay issuance of the proposed FIP until after supply chain challenges have been resolved. The commenters recall past comments (that focus on the current shortage of transformers) they prepared on this issue and asks that the EPA consider those comments, in addition.

Commenter (0547) argues that a post-COVID world requires consideration of additional obstacles, including supply chain issues and negative market conditions, all of which, according to the commenter make the proposed compliance timeline unachievable, and none of which were considered in the proposed rule. The commenter further asserts that the option or opportunity to apply for an extension will likely not solve these issues.

Response:

Comments on EPA's proposed 36-month timeframe for SCR retrofit are responded to in Section VI.A.2.a of the preamble.

With regards to EPA's use of International Brotherhood of Boilermakers (IBB) Union's active membership (47,615 membership in 2021) as a line of evidence to support a finding that there is sufficient skilled labor available to install the retrofit technologies, some commenters do not agree that "the number of memberships to an organization directly reflect availability of workers that could install these projects" (commenter 0290). However, to become an IBB union journeyman, the prospective worker will typically enroll in a 3.5 to 4 year apprenticeship training program offered by the IBB. The apprenticeship program provides both classroom as well as on-the-job training.[107] Therefore, membership to this organization reflects comprehensive professional training. Furthermore, membership in the IBB has varied considerably in the past depending on the market demand for boilermaker services. There was an over 35 percent membership increase (approximately 6,700 members) in the union boilermaker numbers in a two-year period from 1999 – 2001 (which IBB confirms consisted mostly of new members, rather than retired members returning to work). During that time, the boilermaker numbers quickly expanded due to the demand exerted by the construction of SCRs required for the NO_X SIP Call and construction of natural gas power plants to meet the increasing demand for electricity. While the EPA believes the current number of boilermakers will provide sufficient labor availability to install all of the SCR retrofits in this rule in the implementation timeline, the rapid increase in membership over a short period of time demonstrates that the boilermaker union is able to respond to changes in market demand.[108] Further discussion on the availability of skilled boilermaker labor can be found in the EGU NO_X Mitigation Strategies Final Rule TSD.

10.5.7 Unique Challenges for San Miguel

Comments:

Commenter (0385) asserts that power market compensation dynamics and San Miguel's corporate structure make an SCR retrofit financially impossible, and further claims that even if that was not the case, it would be infeasible from a timing perspective to retrofit for SCR by the 2026 ozone season. According to the commenter, based on technical analysis conducted by San Miguel and engineering consultants, the "all-in" cost to retrofit for SCR conservatively would be $240,000,000 (includes $50,000,000 for equipment, $90,000,000 for direct construction, and $35,000,000 in construction management and engineering costs). The commenter states that electric cooperatives (like themselves) are not-for-profit entities – they have no investor equity shareholders who can bear the costs of investment in new equipment. The commenter explains that any additional cost incurred as a result of compliance and SCR installation (costs of borrowing) are necessarily passed on to cooperatives' members, who invariably pass them on to their consumers (under the proposed FIP, expect increases in the amount of hundreds of millions of dollars). The commenter underscores the point that, given that electric cooperatives serve rural areas, there are relatively few customers to spread those costs across. The commenter further adds, given that cooperatives only maintain marginal cash

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107 https://boilermakers.org/apprenticeship

108 "Boilermaker Labor Analysis for the Final Clean Air Interstate Rule TSD" https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech05.pdf

reserves for unforeseen events and anticipated operating expenses, financing for many capital projects necessarily requires reliance on debt investors such as the United States Department of Agriculture's RUS.

The commenter states that because retrofitting for SCR is financially untenable, they assessed SCR compliance alternatives and found that San Miguel's SNCR system, even if optimized, will be unable to achieve the "backstop" 0.14 lb/mmBtu NO_X limit under steady-state conditions. The commenter clarifies that if non-SCR units would not be permitted to run during ozone season, the overhead required by the commenter to run the plant (San Miguel) only in the seven non-ozone season months may not justify continued operation. The loss of the San Miguel plant negatively impacts the community, job market, etc. – *e.g.*, San Miguel provides jobs to 467 people at its mining and power plant facilities and indirectly, supports another 1,200 regional jobs; and provides $1.9 million a year in local taxes. The commenter recalls millions of dollars-worth of investment ($139 million) on control equipment, including, for example, SNCR and other enhanced NO_X controls, including low NO_X burners. The commenter states that premature retirement of the plant would strand these significant investments. The commenter concludes, based on technical analysis conducted by the commenter and engineering consultants, few if any utility scale SCRs have been installed in the United States in recent years, and labor shortages and supply chain delivery issues—not to mention the 1+ year timeframe needed to obtain RUS financing—would extend the timing of a retrofit project.

Response:

The EPA has extended the timing of the state-level SCR-premised emissions reductions (as expressed in the trading budgets) and the start date of the daily backstop rate in this final rule, both changes that accommodate timing concerns raised by the comment. The EPA also notes that the seasonal emissions rate for the particular unit cited by commenter has ranged from 0.156 lb/mmBtu to 0.164 lb/mmbtu over the 2017-2021 timeframe. The EPA has delayed the daily backstop rate to no later than 2030 in this final action, but even at that point the 3:1 surrender requirement for exceeding the daily backstop emissions rate only applies to the overage (e.g., 0.156 – 0.14 = 0.016 lb/mmBtu) and only applies after the first 50 tons of overage. San Miguel can also consider retrofitting SNCR to achieve some reductions; while not as effective as SCR, SNCR would lower NOx emissions for those critical times. Even in the event that San Miguel chose not to retrofit and could find no additional mitigation measures, it could continue to operate at recent levels and only a small portion of San Miguel's emissions at most (assuming that at least current emissions rates could be maintained) would be subject to the 3 to 1 surrender requirement. Compliance with the trading program is feasible for this unit (and others similarly situated), even with the onset of the backstop rate in 2030.

10.5.8 Reactivating Idle SNCR System – Timeframe

Comments:

Commenter (0361) claims that the EPA underestimates the timeframes necessary to reactivate idle SNCR systems. The commenter notes that some systems have remained idle for significant enough time to necessitate repairs or partial replacement; and some have had other post-combustion controls (lime and carbon systems) to limit MATS emissions added in the intervening period while the SNCR system was inactive. According to the commenter, testing is needed to determine whether reactivation of these systems will be harmful to the locations where lime and carbon are injected, and determine whether the interaction will affect the operation of these other control systems. Furthermore, the commenter suggests that additional time is also needed to determine how the added ammonia will impact the disposal of coal ash, since it will likely contain ammonia, if the SNCR is brought online.

Response:

See the EGU NOx Mitigation Measures Final Rule TSD for a discussion on SNCR optimization timing. The EPA also notes that similar timing assumptions were made and implemented successfully in Revised CSAPR Update Rule that went into effect in 2021. Finally, for sources in Group 2 CSAPR states, 2022 data indicate that some optimization has already occurred during that compliance period. This indicates that less incremental measures may be needed to bring SNCR-equipped units into full operation in 2023.

10.5.9 SCRs and Non-EGUs

Comments:

The commenter (0409) explains that state budget assumptions for future years (2026 and beyond) are unworkable. The commenter notes the following: First, the EPA assumes technology retrofits can occur in aggressive timeframes that cannot be met. Combustion modifications must occur by 2023 – less than a year from when the Proposed Rule is expected to be finalized. SCR installations are due by 2026 or within 3.5 years. The commenter states that, as explained in detail in Section VIII.B of their comment letter, units cannot achieve either project in time. Second, state budgets reduce ozone season allocations based on emissions rates for combustion modifications for coal-fired units. These rates are unattainable by any type of boiler combusting bituminous coal by a large margin. Section VIII.D of the commenter's letter lays out attainable emissions rates by coal type and boiler type.

In conclusion, commenter (0409) requests that state budgets be recalculated using achievable assumptions commensurate with appropriate time frames for project completion and technology. The commenter provides that the Technical Report recalculates nine state budgets as examples. The commenter notes that corrected budgets rectify unit-specific errors and apply achievable budget assumptions. NRECA asks EPA to recalculate all state budgets consistent with these examples.

Commenter (0379) writes in opposition to the EPA's proposed timing requirements for post-combustion controls on coal fired EGUs, stating that they are unjustifiably long given that the emissions controls manufacturers stated, in 2006, that complete (new) SCR installation, startup, and optimization can be accomplished within 48 weeks. The commenter notes that SNCR technology could be installed in an even shorter time, as EPA acknowledges: "SNCR installations generally have shorter project installation timeframes relative to other post-combustion controls." The commenter states that the optimal running of existing SCR and SNCR technology would take a fraction of the time of a new installation. The commenter asks the EPA to require optimal operation of existing SCR/SNCR technologies by the start of the 2023 ozone season, with the application of daily backstop emissions rates in this same timeframe; furthermore, installation and optimal operation of new SCR/SNCR technologies should be required no later than the start of the 2024 ozone season, accompanied by the daily backstops. The commenter writes that there is "no justification in extending these timeframes."

Response:

EGU emissions reductions associated with post-combustion optimization mitigation strategies are anticipated to begin with the effective date of the rule sometime in the 2023 ozone season. See preamble Section V.B and the EGU NO_X Mitigation Strategies Final Rule TSD for a discussion of timing regarding SCR retrofit. In the EPA's judgment it is not possible for SCRs to be retrofit on the relevant EGUs on a fleetwide basis by 2024.

In this final rule, the EPA finds EGU combustion control upgrades are viable by the start of the 2024 ozone season (not 2023) and that post-combustion control retrofits are viable over the 2026 and 2027 time period.

10.6 SCR Performance Rate

10.6.1 SCR Performance Rate: EGUs

10.6.1.1 0.05 lb/MMBtu Emissions Rate

Comments:

Overall, commenters (0290, 0411, 0499, 0533, 0758) disagree with EPA's assertion that the proposed 0.05 lb/MMBtu emissions rate performance is achievable for various reasons, including for example, temperature profiles of SCR systems, and warn, that attempts to reach this rate could result in the generation of other pollutants/chemical reactions that could impact NO_X removal efficiency.

Commenter (0290) disagrees with EPA's assumption that a new "state-of-the-art" NO_X combustion control (new SCR retrofits) could achieve an emissions rate performance assumption of 0.05 lb/MMBtu on a coal steam unit (regardless of type of coal) and achieve a rate of 0.03 lb/MMBtu for an oil/gas steam unit. First, the commenter mentions that Flue gas temperature is one of the most important process parameters in the operation of an SCR – that can impact whether the SCR emissions rates proposed by the EPA can be achieved on a long-term operating basis. The commenter explains that a catalyst is designed to operate within a specific temperature range, called the minimum catalyst operating temperature (MCOT), which limits the operating load range of a boiler such that if the boiler operates at a load below the MCOT, the SCR cannot inject ammonia thereby limiting the ability of the SCR to reduce NO_X. The commenter warns that injection of ammonia below the MCOT will promote generation of ammonium sulfate and ammonium bisulfate (ABS) that will accumulate over time, block catalyst sites, and reduce long term catalyst activity. As the catalyst degrades over time or is damaged, the commenter highlights that the NO_X removal efficiency decreases. According to the commenter, for units that low load cycle, ammonia would not be injected if flue gas is not at the MCOT, which reduces times when NO_X emissions are actively controlled by the SCR. Furthermore, the commenter observes that the EPA proposed FIP fails to consider any operating margin – that would be required due to changes in external market forces (*e.g.*, weather conditions, unplanned forced outages, extended planned outages and short-term changes in seasonal demand) which would negatively affect unit dispatch and in turn affect the unit's ability to meet the NO_X emissions rate – when developing the achievable NO_X emissions rate for coal and oil/gas fired boilers. Additionally, the commenter states although EPA based performance of new retrofit SCR controls for coal-fired boilers at 0.05 lb/MMBtu, the allocations provided to units with existing SCRs are lower than what EPA identified as the achievable emissions rate for state-of the art SCR retrofits.

Commenter (0411) asserts that the expected emissions rates (of 0.05 lb/mmBtu for newly installed SCRs, and 0.08 lb/mmBtu for those units with optimized controls) are not reasonably obtainable for prolonged periods of time without significant ownership costs in the form of catalyst replacement and ammonia usage. The commenter expresses concerns about the possible increase in ammonia slip – that can lead to secondary $PM_{2.5}$ formation – as a result of increased amounts of ammonia needed to control NO_X emissions in an effort to meet emissions rate targets. The commenter briefly discusses sip and ammonium bisulfate are formed, and the impacts (to health and air quality) of these formations, and questions whether or not ammonia slip contributes to early degradation of the catalyst.

Commenter (0499) believes that the EPA has overestimated the EGU sector's NO_X emissions reduction potential, in part, because EPA has an unrealistic and over-simplified understanding of NO_X control technology installation at EGUs. More specifically, the proposed FIP overestimates the emissions rates reductions achievable with SCRs. The commenter disagrees with the determination of consistently achievable NO_X emissions rates for coal-fired EGUs – a NO_X emissions rate of 0.05 lb/mmBtu (for new and existing SCRs), when optimized, can consistently achieve an emissions rate of 0.08 lb/mmBtu. The commenter stresses that although these rates may be achievable in the short-term (when a unit's catalyst is new), they cannot be sustained at many units over time. This is particularly true for coal-fired EGUs that have increased cycling operation, undergo frequent operation at minimum load and more frequent startups and shutdowns, all of which affect a coalfired EGU's ability to start up and maintain reliable operation of SCR control technology. The commenter emphasizes that only a few EGUs (identified in the NEEDS database) currently meet the proposed NO_X emissions rate for new SCR retrofits (0.05 lb/mmBtu or less). Additionally, the commenter discloses that they are unaware of any consent decrees or PSD permits requiring such a low NO_X emissions rate averaged over the ozone season. According to the commenter, utilities will face a significant increase in maintenance costs, including more frequent catalyst changes and other operational changes to achieve the proposed rate. The commenter believes that it is unreasonable (and unsupported) for EPA to assume, that on average, an emissions rate of 0.05 lb/mmBtu for large coal-fired EGUs for the purposes of establishing state budgets beginning in 2026.

Commenter (0553) believes that an emissions rate of 0.05 lb/mmBtu to EGUs (expected to be installed SCR by 2026) may be achievable for initial operation of a new SCR, although even initially the actual performance may be affected by the unit's utilization rate and impacts of low load on SCR performance. The commenter claims that achieving an emissions rate of 0.05 lb/mmBtu leaves little or no room for these units to outperform the budget expectation, which limits the ability to create allowance margin to support the market trading program. According to the commenter, performance even in these new units would also be expected to vary year by year due to catalyst degradation and the periodic maintenance cycle for catalyst replacement, further adding to the concern. In the commenter's case, while they have installed SCR on all of their EGUs under the 2021 Revised CSAPR Update and the proposed FIP, the effect of applying the new SCR emissions rate at 0.05 lb/mmBtu will be to lower a state's emissions budget which then directly impacts the allowance markets – allocations to the commenter's facilities in 2026 and later.

The commenter (0758) underscores the point that a routinely achievable rate is not the same as a rate that reflects the level of performance that is widely achievable for well-run and fully operating SCR if SCR operations have not previously been routinely optimized; insisting that the budgets should reflect the latter. The commenter claims that the EPA's data show the lowest monthly average ozone-season NO_X rate from 2009 to 2021 was 0.048 lb/mmBtu, with second and third lowest monthly average rates of 0.057 and 0.062 lb/mmBtu respectively, while the lowest seasonal average ozone-season NO_X rate was 0.060 lb/mmBtu. The commenter clarifies that for the analysis of newly retrofitting a unit with SCR, the EPA assumes a new state-of-the-art SCR retrofit can achieve a 0.05 lb/mmBtu emissions rate performance on a coal steam unit. According to the commenter, all of this information suggests a ceiling rate between 0.065 and 0.071 lb/mmBtu would still be widely achievable and a better approximation of the rate that can be achieved by a well-run and fully operating SCR.

Response:

Section V.B.1.e of the preamble and the EGU NO_X Mitigation Strategies Final Rule TSD describe why EPA found that new SCRs retrofit on coal steam units can achieve NO_X emissions rates of 0.05 lb/MMBtu (and 0.03 lb/MMBtu rates for SCR retrofits on O/G Steam units). This included that vendors are willing to guarantee performance at these rates, and those guarantees apply to the lifetime of the catalyst, not just when all of the catalyst is new. SCR maintenance and replacement of the catalyst can ensure this rate can be met. Regarding comments that SCRs can only function at the minimum catalyst operating temperature, the Section V.B of the preamble and the EGU NO_X Mitigation Strategies Final Rule TSD provide examples of units that changed their operation to ensure they operate at or above the minimum temperature necessary for SCR operation. Regarding comments that operating SCRs at the optimized levels could result in ammonia slip and the formation of ammonium bisulfate and $PM_{2.5}$, the EPA notes that these can be avoided through a variety of means such as: ensuring operating at a minimum temperature or artificially managing the temperature with economizer modification or duct burners; tuning the reagent injection system; combusting lower sulfur content fuels; incorporating byproduct removal design features like soot burners; removing buildup during scheduled outages; and adding a DSI system to lower sulfur in the combustion gas stream. The issue regarding ammonia byproducts build-up has not prohibited the current

SCR community from effectively operating their installed SCRs. See "" IPM Model – Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers" (February 2023). Finally, the EPA notes its use of the 0.05 lb/mmBtu rate is as an average, not a ceiling. Sources are not required to continually operate below this level, rather state emissions budgets are premised on them being able to achieve this level on average. This allows for instances where an individual source may not operate at or below this rate.

10.6.1.2 0.012 lb/MMBtu Emissions Rate

Comments:

At large, commenters (0290, 0554) disagree with EPA's conclusion that "an emissions rate of 0.012 lb/mmBtu is widely achievable by the portion of combined cycle EGU fleet with SCR optimization potential identified." Specifically, the commenters suggests that the proposed FIP fails to consider physical limitations in locating an SCR and the unit's actual historical capacity factor.

Commenter (0290) maintains that, for gas-fired combined cycles, physical limitations in locating an SCR could be challenging and, in some instances, not possible. There may not be physical room to install the catalyst or for an optimized SCR, not enough space to expand and add additional volume to meet a lower/optimized NO_X emissions rate of 0.012 lb/MMBtu. In addition, an increase in ammonia injection rate above the SCR's original design could cause balance of plant impact such as an increase in secondary emissions such as ammonia slip. According to the commenter, existing combined cycle facilities with SCR units in place, that are looking to further reduce NO_X emissions, will need to evaluate available space inside the reactor for extra catalyst volume or activity – a potential issue at the CPS Energy Arthur Von Rosenburg Station as the existing SCR may not have adequate room to expand for additional catalyst, if deemed necessary. For combined cycle facilities originally built without SCR, the commenter points out that if extra space in the HRSG was not dedicated for the future Ammonia Injection Grid (AIG) and catalyst, it may be impossible to retrofit the facility with SCR. The commenter warns that simple cycle units looking to add an SCR unit would see high costs as well, due to either the use of a high temperature system that can be placed immediately downstream of the combustion turbine, or a larger SCR reactor that would require tempering air. The commenter notes that this is a potential issue at CPS Energy Rio Nogales Station as the unit may not have adequate room to expand for catalyst.

Commenter (0554) argues that optimization of existing SCR on combined cycle combustion turbines to consistently achieve 0.012 lb/mmBtu, irrespective of the unit capacity factor is, according to the commenter, unreasonable. Appendix A of the Proposed Rule assumes BHE Renewables' Cordova Unit 1 can optimize SCR even though it achieves 0.012 lb/mmBtu (2019-2021 average) at 48 percent capacity factor. The commenter notes that the EPA also assumes that BHE Renewables' Saranac Units 1 and 2 can optimize SCR based solely on average NO_X emissions in 2019-2021 of 0.03 lb/mmBtu, without respect to the fact that the capacity factor during those years was only one percent. The EPA should consider the capacity factor of a unit with existing SCR prior to determining whether that unit should be required to optimize the existing SCR. Based on the commenter's experience in operating these facilities, indicates that units at such low capacity factors cannot further optimize operation of SCR to "consistently achieve" EPA's assigned best-in-class emissions factor of 0.012 lb/mmBtu.

Response:

Section V.B.1.a of the preamble and the EGU NO_X Mitigation Strategies Final Rule TSD describe why EPA found that combined cycle units with existing SCR can achieve NO_X emissions rates of 0.012 lb/mmBtu. However, the EPA found that SCR retrofits on combined cycle units were "beyond the knee in the curve" and reductions commensurate with such retrofits were not included when calculating state emissions budgets.

10.6.1.3 0.08 lb/MMBtu Emissions Rate

Comments:

Overall commenters (0394, 0395, 0430, 0500, 0553, 0758) disagree with EPA's assumption that units currently operating SCR can widely achieve a 0.08 lb/mmBtu NO_X emissions rate and state their belief that the proposed rate is inconsistent with the technical capabilities of certain units, does not reflect the result of its own methodology, and may result in an increase in pollutants (ammonia slip) – just to name a few.

Commenter (0394) states that in the Proposed Rule, the EPA assumed that NO_X emissions reductions will be achieved through optimizing the use of SCR and selective noncatalytic reduction (SNCR) equipment already in place by the 2023 ozone season, and through installation of new SCR and SNCR equipment by the 2026 ozone season. The commenter claims that a number of assumptions made by the EPA relating to the availability and capability of SCR and selective noncatalytic reduction (SNCR) equipment and the cost of any reductions derived from the use of this equipment are flawed; resulting in unrealistic projections and artificially low NO_X emissions budgets.

In a similar comment, commenter (0394) claims that the EPA's estimates of the NO_X emissions reduction performance that can be achieved through optimization of existing SCRs are flawed. More specifically, the commenter states that the assumption that maximum NO_X removal potential for an SCR is equivalent to the NO_X emissions rate achieved during the third lowest ozone season since 2012 ignores that NO_X control performance degrades over time with the state of the catalyst and the ability to maintain a uniform mixture of ammonia reagent to NO_X generated in the boiler. The commenter believes that it is unrealistic to assume that existing units can achieve the same NO_X rates that they achieved historically on a year-to-year basis, particularly without significant capital expenditures and increased operations and maintenance costs. Additionally, the commenter claims that the methodology that the EPA used to estimate the capital cost of installing SCR and/or SNCR at units throughout the 25 states covered by the Proposed Rule is outdated and unrealistic – *e.g.,* fails to capture the variability in operating costs. The commenter asserts that the capability range identified for SNCR controls (20 to 40 percent) misjudges the complex procedure of introducing ammonia reagent during a narrow temperature window to optimize NO_X reduction and the variability in NO_X emissions reduction that can occur during this process. According to the commenter, the upper limit of SNCR control capability for most units is 30 percent.

Commenter (0395) observes that in determining the appropriate emissions rate to assign to SCR-controlled coal-fired units under this rule EPA looked to units currently operating in the U.S. The commenter restates an excerpt from the TSD explaining EPA's findings on EGU control strategies – the determination and identification of the emissions limit of 0.08 lb NO_X/MMBtu as a reasonable representation for full operational capability of an SCR. Initially, the commenter asserts that using the third-lowest emissions rate is not correct given that the NO_X control performance degrades with the condition of the catalyst. The commenter notes that while the EPA assumes that the catalyst is regenerated every three years, experience shows that the catalyst and the ability to achieve a high degree of ammonia-to-NO_X uniformity can change year-to-year. The commenter maintains that such NO_X rates can be readily attained from existing equipment – or, attained without capital expenditure to refresh an entire inventory of catalyst, or incur higher variable O&M costs than EPA projects. The commenter asks that the EPA determine the average time between catalyst regeneration and then take the lowest value during that time to set an achievable rate. Additionally, while 95 percent of the units could meet 0.08 lb/mmBtu on a seasonal basis, according to the commenter, five percent of the well-run and well-maintained units could not. The commenter questions the reasoning for EPA to establish a proposed rate of 0.05 lb/mmBtu for new retrofits, when in previous rulemaking a higher rate was acceptable – *e.g.*, in the 2021 CSAPR Update, the EPA established a rate of 0.07 lb/mmBtu for coal-fired units. According to the commenter, it is not at all sufficient to set a rate at a level "many" units can meet, but rather, these rates must be achievable on a consistent basis, year after year, for the type of electric generating unit, allowing for variability based on the differences between units (vintage, manufacturer, duct burning, fogging, etc.). The commenter recommends that the EPA set the rate for retrofits at 0.08 lb/mmBtu based on the study of well-run, well-maintained systems, but certainly no lower than the 0.07 lb/mmBtu.

Commenter (0430) remarks focus on and/or are specific to the NIPSCO Michigan City Generating Station. According to the commenter, SCR effectiveness is dependent on the uncontrolled NO_X emissions level, fuel type, age of the EGU and SCR equipment, type and age of the catalyst, unit configuration, load, and other variables – factors that can impact performance but were not considered by the EPA when conducting modeling and developing the emissions budgets. The commenter claims that NIPSCO's Michigan City Generating Station, which has continuously operated SCR for many years, cannot reasonably achieve an average emissions rate of 0.08 lb/mmBtu. According to the commenter, NIPSCO is subject to consent decree NO_X emissions limitations, based upon the expected optimal performance for NIPSCO's SCR equipped, cyclone-fired units at 0.10 lb/mmBtu. The commenter recommends that the EPA develop a more conservative and accurate expectation of SCR performance on a unit-by-unit basis, or account for unit-specific capabilities in instances where a company has provided justification. At minimum, the commenter asserts that the EPA should include categories of various unit design factors, including high uncontrolled NO_X rates, and set appropriate NO_X emissions rate expectations for each category.

Commenter (0500) asserts the assignment of ozone season NO_X rates for SCR equipped coal-fired units below 0.08 lbs/mmBtu is inappropriate. Foremost, the commenter contends that the

EPA's assumption that SCR-controlled units will consistently perform substantially better than a NO_X emissions rate of 0.08 lbs/mmBtu is largely unrealistic. Additionally, the commenter maintains that the Agency should not use nationwide EGU SCR performance data to assess the capability of specific EGU SCRs in the transport proposal region. The commenter warns that the proposed NO_X emissions standard or control requirement identified for units may suggests extremely efficient SCR performance that may not be consistently achievable on a long-term, year-to-year basis – over the course of a catalyst replacement cycle. The commenter asks that the EPA base allowance budgets on a reasonable rate of not less than 0.08 lbs/mmBtu, which represents efficient SCR performance and accounts for the possibility that even well controlled units will experience degradation of performance over time – a consideration particularly important as units begin to cycle and operate more often at low load (as generation continues to include more renewable sources). The commenter recognizes that SSM events can result in higher emissions rate and recommends that the EPA propose a work practice standard in lieu of the requirement to hold allowances for those emissions. Second, according to the commenter (0500), operating SCRs to ensure NO_X rate below 0.08 lbs/mmBtu may cause unintended consequences – *e.g.,* ammonia consumption will increase since the SCR will be removing more NO_X. The commenter explains that reducing the NO_X emissions target results in an increased minimum reactor potential requirement, because the NO_X removal rate is increased – likely resulting in more catalyst replacements over time. The commenter further notes that replacement catalyst designs to accommodate the increased NO_X removal rate may require larger catalyst beds and/or catalyst with increased NO_X removal potential, which typically results in higher oxidation of SO_2 to SO3. The commenter suggests that the condition of the catalyst (*i.e.,* aged catalyst vs. new catalyst), the increased NO_X removal demand is likely to result in an increased average ammonia slip. The commenter states that residual ammonia slip exiting the SCR is of particular concern since ammonia will react with SO3 to form ammonium sulfate and bisulfate compounds. More specifically, ammonium bisulfate (ABS) compounds cause fouling of the heat transfer surfaces of the air preheater, resulting in increased pressure drop requiring shutdown and cleaning of the air preheater. Additionally, the commenter notes that ABS formation on the catalyst surface and within the catalyst pores is controlled by calculating a unit's minimum ammonia injection temperature (MIT) and minimum operating temperature (MOT), so the increased ammonia injected to accommodate the increased NO_X removal rate results in less unit low load turndown flexibility. According to the commenter, an increase in ammonia slip can potentially adversely impact ash sales for beneficial uses, such as cement production, because ammonia is undesirable in the ash. Furthermore, the commenter notes that the increased NO_X removal rate and subsequent increased presence of ammonia may lead to some suppression of mercury oxidation benefits of the SCR, which in turn may increase demand on other systems to compensate – *e.g.,* additional halogen injection. The commenter clarifies that, units typically operate with a NO_X setpoint lower than the permitted limit to allow for some margin to accommodate operational fluctuations and ensure permit compliance; so, a NO_X emissions target of 0.06 lbs/mmBtu would likely mean operating SCR even lower to ensure a sufficient margin is maintained.

Commenter (0553) recommends that in setting the NO_X budgets, the EPA not apply an SCR emissions rate lower than 0.08 lb/mmBtu for any unit operating with an existing SCR. The commenter suggests (as an alternative) that the EPA should apply an "operational variability" margin (of at least 125 percent above the historic rate) to a unit's actual emissions rate to adjust the value not to exceed the existing SCR "achievable" emissions rate (EPA's proposed 0.08 lb/mmBtu). As an example, the commenter describes a unit with a 2021 emissions rate of 0.06 lb/MMBtu would have budgets set based on a rate of 0.075 lb/mmBtu. For units which will be included in the 2026 budgets with new SCR, the commenter clarifies that some margin above 0.05 lb/mmBtu is also necessary to account for year-to-year variation in performance (*e.g.,* catalyst degradation and replacement cycle). The commenter maintains that by setting the technology-based emissions rate (0.08 lb/mmBtu) as a cap assigned to each unit rather than as an average expected performance for all affected sources, the EPA is increasing the stringency of the state budgets beyond the basis it used in its control technology analysis. Furthermore, the commenter contends that by establishing these actual 2021 emissions rate (below 0.08 lb/mmBtu) as the permanent basis for setting state budgets, the EPA fails to recognize the concept of "average" performance, the need to build margin into unit operations, the negative impacts on the NO_X Budget Trading Program, and it disincentivizes units to perform better than needed to comply with the allocations they have on hand. The commenter reminds that the final Revised CSAPR Update rulemaking, issued less than one year before the proposed FIP, the EPA supported the use of "a fleet-wide average" and "creating space for other sources to achieve different rates on different schedules while collectively complying with the state emissions budget;" and questions EPA's decisions to limit this flexibility by removing any additional allowance margin that sources were able to achieve by improving performance beyond 0.08 lb/mmBtu (86 FR 23092). The commenter briefly describes steps taken (on eight coal-fired boiler EGUs) during the 2021 ozone season (in responding to the Revised CSAPR Update Rule's Group 3 program) to push NO_X emissions rates as low as practicable in an effort to build margin to support a long-term compliance plan that considered reduced future year budgets and allocations, future forecasts for generation, and uncertainty in development of a robust Group 3 allowance market; resulting in a reduction in emissions rates (for affected units in Indiana) – seven of the eight units had rates below the average SCR level identified by the EPA.

Commenter (0758) claims that the EPA's chosen "ceiling" emissions rate for optimizing SCR is excessively high and does not reflect the result of its own methodology. The commenter insists that the EPA utilize a lower maximum emissions rate (between 0.065 and 0.071 lb/mmBtu) at coal-fired units that have optimized their SCRs when establishing the budgets. The commenter explains that, according to EPA, the methodology for identifying an emissions rate of 0.08 lb NO_X/mmBtu is consistent with the one used in the Revised CSAPR Update, which the commenter highlights, "focused on the third-lowest ozone season NO_X rates achieved since 2009." However, the commenter notes that the third-lowest season average ozone-season NO_X rate, as suggested by the EPA's supporting information, is 0.071 lb/mmBtu. The commenter argues that the EPA and independent analysis agree even those units that are running at low-capacity factors should be able to achieve a NO_X rate with optimized SCR well below 0.08 lb/mmBtu. According to the commenter, seasonal and monthly emissions data in the EGU NO_X Mitigation Strategies Proposed Rule TSD support use of a ceiling rate of between 0.065 and 0.071 lb/mmBtu in the budget for optimizing SCR at historically poor performing units. The commenter argues that while the third best seasonal average rate of 0.071 lb/mmBtu (which is also the fifth lowest monthly average rate) is routinely achievable, the second-best seasonal rate of 0.065 lb/mmBtu is still conservative and should also be considered routinely achievable.

Response:

The EPA treats the 0.08 lb/mmBtu as the average achievable performance rate for units that are not currently optimizing their SCRs. This is covered in Section V.B.1.a of the preamble. The EPA assumes that units performing better than this in 2021 can continue to operate at that same level going forward as described in the Ozone Transport Policy Analysis Proposed Rule TSD. The EPA never intended to or indicated that 0.08 lb/mmBtu was its assumption regarding the entire SCR-controlled fleet, and in fact explained that the SCR-controlled fleet on average performs better than 0.08 lb/mmBtu.[109] Moreover, the 0.08 lb/mmBtu rate is applied as an average for the non-optimized units, and the resulting mass-based state budgets and interstate trading program would allow some units to emit more than this, and some less than this rate, while still meeting the 0.08 lb/mmBtu on average across the non-optimized fleet and thus complying with state emissions budgets, assurance levels, and allowance holding requirements.

The values the EPA uses in its baseline are the calculated values, contrary to commenter's assertions. That is, the EPA uses total reported ozone-season heat input and total ozone-season emissions rate for the unit to calculate the emissions rate for each unit. The 0.08 lb/mmBtu fleetwide assumption is derived in the same way (assessing total emissions divided by total heat input), and thus applying the rate back to a unit's heat input allows for the calculation of tons under an optimization scenario in a manner consistent with the derivation method.

We note that Wisconsin upheld the reasonableness of the approach to establishing a fleetwide optimized rate assumption for SCR-equipped units. *See* 938 F.3d 303, 320-21.

10.6.1.4 0.199 lb/MMBtu Emissions Rate

Comment:

Commenter (0409) claims that the EPA proposed FIP over-estimates the effectiveness of state-of-the-art NO_X combustion controls. According to the commenter, NO_X combustion controls cannot achieve 0.199 lb/mmBtu, particularly for units combusting bituminous coal, and asks that the EPA correct this faulty assumption in the proposed FIP and adjust state budgets to reflect achievable rates. The commenter asserts that the data used to establish the rate is based. The commenter asserts that the dataset is flawed because it claims units are bituminous, but instead contains atypical cases of western bituminous, refined coal, or co-fired fuels. Based on the commenter's experience, only newer generating units using low burner zone liberation rates can meet average emissions rate assumptions. The commenter remarks include a table listing average achievable NO_X emissions rates and proclaims that feasible NO_X reductions for bituminous units are much higher.

[109] 85 FR 68990.

Response:

As illustrated by both EPA and commenter data (Figure 4-1 and Figure 4-2) of attachment 7 (EPA-HQ-OAR-2022-0668-0323), units with state-of-the-art combustion controls have on average performed at or better than EPA assumed rate across boiler types. Moreover, both data sets illustrate that the rate has been across a variety of coal types. Finally, EPA assumed emissions rate for budgeting purposes is well within the range widely demonstrated for this technology. While bituminous units may generally fall on the higher side of this average historically, that does not mean EPA should change its representative value. Furthermore, commenters analysis suggesting higher rates based off more granular segmentation of the fleet (*e.g.*, 0.30 lb/mmBtu) for a specific boiler/coal combination not only is misleading of what the units identified in EPA's Engineering Analysis could achieve, but even misses the fact that they are already performing better than these commenter highlighted rates without an upgrade (0.26 lb/mmBtu on average). In other words, applying some of the combustion control performance rates suggested by commenter (*e.g.*, 0.30 lb/mmBtu) would counterintuitively and incorrectly result in an emissions increase at units who add state-of-the-art combustion controls in most cases. Moreover, the performance rates are intended to be representative, not a lowest common denominator, and the use of a representative value is appropriate given EPA's trading program implementation and the fact that no unit-specific emissions rate associated with the implementation of combustion control mitigation measures.

10.6.1.5 Idling, Failure to Optimize SCR

Comments:

Overall, commenter (0492) agrees with EPA's assessment that many EGUs are not optimizing their pollution controls consistently throughout each day of the ozone season and, thus, are not achieving the emissions reductions necessary to aid downwind states as required under the good neighbor provision. The commenter references a few supporting documents/attachments available in the docket as support – *e.g.,* the Discussion of Short- Term Limits document (EPA-HQ-OAR-2021-0668-0124), which analyzes 2017 emissions data to determine whether coal-fired EGUs were idling their SCR controls or sub-optimally operating them. The commenter contends that a daily emissions rate limit will help incentivize SCR optimization to secure the emissions reductions required by the good neighbor provision. Aside from that conclusion, the commenter maintains that the Agency fails to explain the other metrics and statements employed throughout the memo, and the memo's conclusions are entirely unpersuasive. The commenter highlights that the memo only analyzes 2017 emissions data, the first season subject to the Cross-State Air Pollution Rule (CSAPR) Update (81 Fed. Reg. 74,504 (Oct. 26, 2016)), which is not indicative of later years, when the number of banked allowances increased, and sources could buy less expensive allowances to cover increased emissions. To remedy this deficiency, the commenter refers back an attached analysis (Ozone Transport Policy Analysis Proposed Rule TSD, Appendix A) that uses emissions data from the three most recent years of 2019–2021.

To begin, the commenter (0492) notes that the EPA declares that units with ozone season average NO_X rates below 0.2 lb/MMBtu "were likely operating their [SCR] controls throughout the ozone season." EPA, Discussion of Short-term limits, EPA-HQ-OAR-2021-0668-0124. The commenter contends that the EPA provides no data/analysis to support the establishment of an 0.2 emissions rate – double the expected rate under the CSAPR Update in effect in 2017. A flawed metric, which the commenter confesses is even harder to justify under the current proposal where the expected ozone season average emissions rate for optimized SCR has been lowered to 0.08 lb/MMBtu. Looking at the results of an analysis performed (Attachment E - Summary of EGUs Flagged by the EPA for Optimization), the commenter observes that 34 out of the 40 units had average seasonal emissions rates over 0.08 lb/MMBtu in 2021, with similar results in 2020 and 2019. As a second metric, the EPA pointed to hourly NO_X emissions rates more than 20percent higher than a unit's seasonal average as evidence that the unit was not operating its SCR at optimal levels. Moreover, the commenter observes that the EPA points to hourly NO_X emissions rates more than 20percent higher than a unit's seasonal average as evidence that the unit was not operating its SCR at optimal levels; however, provides no rationale for the 20percent cut-off. The commenter adds that the EPA only ran this test on EGUs in a subset of states, mostly in the mid-Atlantic (Pennsylvania, New Jersey, New York, Delaware, Connecticut, and Maryland) and in doing so, found only two units that satisfied this arbitrary metric. As a third metric in the memo, the commenter reminds that the EPA looked at whether a unit's hourly NO_X rate doubled during the course of a single calendar day, indicating that the SCRs were turned down or off periodically. The commenter agrees that a doubling of the hourly rate could very well be one indication of an SCR idled or sub-optimally run, but underscores the point that the EPA, without explanation, went on to flag only those units that had at least 20 days with an hourly rate doubling. The commenter questions the lack of explanation for why it looked at 20 days or more.

The commenter references the following percentages of units cycling their SCRs, based on the analysis (Attachment E - Summary of EGUs Flagged by the EPA for Optimization): 2021 – 67.5percent (27 out of 40 units); 2020 – 55percent (22 out of 40); and 2019 – 65percent (26 out of 40). The commenter suggests that the number of days of SCR cycling for some of these units is very high, and provides a few examples as support – *e.g.*, in 2021, the East Bend Unit 2 in Kentucky cycled its SCR on 88 days, out of an ozone season of 152 days.

The commenter suggests that even units that had seasonal NO_X emissions rates meeting EPA's proposed limit of 0.08 lb/MMBtu cycled their SCR for many days each season, demonstrating that only a daily rate will end this harmful practice – *e.g.*, in 2021 the DB Wilson unit in Kentucky had an average seasonal rate of 0.08 lb/MMBtu, and yet it cycled its SCR for 48 days, and seven days exceeded the proposed daily limit of 0.14 lb/MMBtu.

The commenter refers to Attachment F spreadsheet tabs labeled "Additional SCR Units" and "Additional SCR Units Summary," as proof that there are potentially many other EGUs that are not optimizing their SCRs. The commenter also names Ranajit Sahu, US Coal Fleet Selective Catalytic Reduction (SCR) Performance Analysis, at 5-15 (Jan. 2022), which is available in the docket and cited as support.

Response:

Based on historical data, the EPA observes a substantial number of units were not operating their SCR controls to their fullest installed potential. Opportunity exists to restore margin to these pre-existing conditions for these units. The Short-term Limits Document referenced by commenter addressed circumstances in the context of prior rulemaking records that are different or inapposite in a number of ways from the question the Agency is confronting in this rulemaking, including: 1) it only examined the first year of a trading program, whereas much of the record cited by the EPA in Section V and VI of the preamble regarding degradation of emissions performance over time explains how it is in the latter years of a trading program using a fixed budget (e.g., years 2, 3, 4) where the decline in optimization incentive occurs; and 2) it primarily addressed the question of whether the EPA observed a decrease in control performance, on average, on high electric demand days at individual units. The EPA did not assess whether the degradation that the EPA did observe could be of concern at a state- or source-specific level, or in conjunction with impacts to specific receptors on potential specific high ozone days.

10.6.1.6 SCR – NO_X Emission Reduction Via Cost Threshold

Comment:

Commenter (0758) urges the EPA to adopt an approach that reduces the most NO_X emissions at the highest cost threshold that it finds acceptable. Specifically, the commenter recommends two improvements to oil- or gas-fired EGUs control strategies: (1) First, the commenter urges the EPA to eliminate or narrow the threshold of 150 tons of NO_X per ozone season as a prerequisite for assuming installation of SCR on oil- or gas-fired steam EGUs; arguing, in general, that the cost threshold proposed for oil- and gas-fired steam units ($7,700/ton) should be acceptable for all EGUs regardless of higher costs for individual units or subsets of units. The commenter recommends that the EPA consider a narrower exemption if a concern still remains about the cost-effectiveness of SCR retrofits on oil- and/or gas-fired steam EGUs that have emitted below 150 tons of NO_X in recent ozone seasons. To illustrate the point, the commenter states that removing EGUs that have partially or entirely fired with oil from this subset of units would lower the subset's weighted average cost-effectiveness to $14,000/ton, while still potentially reducing emissions by 10,500 tons per ozone season (assuming a capacity factor of 26 percent). Alternatively, the commenter states that removing EGUs with emissions-reduction potentials in future ozone seasons below 150 tons per ozone season would result in a weighted average cost-effectiveness of $14,300/ton while reducing emissions by 18,800 tons per ozone season. As a final alternative, the commenter maintains that removing both EGUs that have not exclusively fired with gas and EGUs that have emissions-reduction potentials below 150 tons per ozone season would result in a weighted average cost-effectiveness of $12,400/ton while reducing emissions by 9,500 tons per ozone season. The commenter underscores the point that the overall cost- effectiveness for SCR retrofits on oil- and/or gas-fired steam EGUs is $7,700/ton – well below the cost-effectiveness of installing SCR on large coal-fired EGUs, at $11,000/ton. Thus, the commenter concludes that the EPA should assume that all of these units retrofit with SCRs for purposes of budget-setting and impose corresponding backstop daily emissions limitations. Second, regarding natural gas combined-cycle units (NGCCs), the commenter suggests that the identified emissions-reduction potential of 3,100 tons of NO_X at 45 units or 4 GW of capacity, with a representative cost-effectiveness of $12,000/ton is not markedly higher than the similar value for installing SCR on large coal-fired EGUs; arguing that the EPA must establish budgets assuming that poorly controlled existing NGCCs also retrofit with SCR.

Response:

EPA explains its Step 3 identification significant contribution in Preamble Section V.D. It notes here that the suggested alternative identification of oil/gas steam boilers with SCR retrofit potential would result in higher cost than that identified by the EPA, would capture units with a wider distribution due to the significantly lower capacity factor and higher yearly variation in operation at these units as opposed the coal fleet and high emitting o/g steam fleet identified as having retrofit potential. The tons of reduction per retrofit project would be significantly lower as these units emit much less on average.

10.6.1.7 Other Comments

Comments:

Commenter (0515) fully encourages EPA to promote the optimization of SCRs and other control technologies where they are feasible; underscoring the point that the proposed emissions control technologies are space-intensive and may not be appropriate for all operating units. The commenter recommends that the EPA should allow operators to submit evidence that such controls are infeasible at a given unit, due to site-specific space constraints or other physical factors. The commenter adds that the EPA could then review this information, determine whether it is credible, and adjust state budgets if necessary or appropriate.

Commenter (0758) supports the proposed timing (beginning in 2023) of optimization of SCRs on large coal-fired EGUs and believes that the proposed timeframe is well supported and any delays in deployment would contravene the CAA’s requirement to eliminate significant contributions to downwind pollution problems as expeditiously as practicable. The commenter recalls that the EPA found that returning SCRs to service can take up to 7 months, and optimizing currently operational SCRs can be accomplished within a similar timeframe; further adding that hourly unit-level data show improved SCR performance within two months The commenter states that an examination of those coal-fired EGUs that have recently been operating SCRs—yet not consistently achieving emissions rates reflecting optimized control—reveals that these units have emitted NO_X at a daily rate below 0.075 lb/mmBtu across much of last year’s ozone season.

Response:

EPA, consistent with commenter input, is finalizing SCR optimization as a viable mitigation strategy for 2023. In regard to comment suggesting sources submit documentation on site-specific limitations prohibiting SCR installation and suggesting EPA subsequently adjust the budget, the EPA notes that such facility-specific proceedings are not needed in the context of an emissions trading program. However, to the extent such concerns present genuine issues of compliance feasibility, the EPA has adjusted increasing the amount of banked allowance carryover each year through 2029 to 21 percent and not applying the daily backstop rate until 2030 for units that are retrofitting with SCR, both of which further accommodate a unit's ability to comply through alternative measures.

10.6.2 SCR Performance Rate: Non-EGUs

10.6.2.1 Technical Feasibility of Add-on Controls (SCR/SNCR) on Ferroalloy Electric Arc Furnace (EAFs)

Comments:

Overall, commenters (0280, 0287, 0298, 0308, 0345, 0359, 0405, 0416, 0435) argue that the EPA's proposal to require add-on controls (like SCR or SNCR) to reduce NO_X emissions is not technically feasible to install or operate at ferroalloy EAF units (due to design and operational characteristics) and, as such, the proposed NO_X emissions limit (0.15 lb/ton) and the asserted control efficiency CE limit (25 percent reduction when applied to EAFs) are arbitrary and capricious. The commenters stress that the EPA provide no basis (or technical information for example that distinguish between limits of new EAF and existing EAFs) to support the assumptions made, and many express concerns that the usage of these NO_X controls inadvertently leads to an increase in generation of other pollutants, including particulates and ammonia that can cause blinding, plugging, masking, or fouling of the catalyst and ultimately impact NO_X removal performance. For these reasons and others mentioned below, several of the commenters urge the EPA not to move forward with this regulation when there are fundamental misunderstandings on whether and how emissions reduction technology has been shown to work at facilities, especially in an economically feasible manner.

Commenters (0280, 0435) contend that SCR technologies are poorly suited to control NO_X emissions from an EAF and express concerns that an SCR requires a catalyst that is subject to fouling by ammonium sulfate may lead to a deactivation of the SCR catalyst.

In a similar comment, commenter (0280) states that the particulate emissions rate of an EAF is between 38 and 50 pounds of particulates per ton of steel, prior to particulate controls, which, the commenter highlights is approximately five times higher than what is typically emitted from a coal-fired boiler. The commenter disagrees with EPA's asserts that catalyst replacement would occur annually (at that particulate loading), and claims that the configuration of placing the SCR prior to the baghouse is technically infeasible, cost-prohibitive, and runs counter to its intent in the proposed FIP – it is likely to increase NO_X emissions from natural gas combustion, defeating both the direct ozone transport and indirect greenhouse gas goals of the proposal.

Commenter (0287) disagrees with EPA assertion that facilities with EAFs can easily install and operate Selective Catalytic Reduction (SCR) to reduce NO_X emissions; noting that the EPA's own RBLC and decades of determinations for EAFs determined that add-on controls, like SCR or SNCR are not technically feasible. To illustrate, the commenter mentions the AMG

Vanadium's BACT analysis prepared as part of the facility's PSD review, which determined controls like SCR are technically infeasible (Application A0063644, May 8, 2019). The commenter explains that SCR removal efficiencies are highly dependent on the NO_X concentration at the inlet, and very low NO_X concentration in the exhaust from AMG Vanadium's EAFs would result in low removal efficiency. Additionally, the commenter notes that AMG Vanadium's EAF process off-gas contains SO_2 and particulates, which are detrimental to SCR catalysts; thus, SCR would need to be installed downstream of its FGD system and its baghouse. According to the commenter, due to the off-gas volumes and temperatures required to run FGD and baghouses, AMG Vanadium would then be required to reheat the off-gas using large amounts of natural gas to maintain temperatures that are consistently above the SCR activation temperature; resulting in an additional 80,000-110,000 TPY of GHG emissions – a highly objectionable trade-off.

Commenter (0298) contends that even if NO_X controls could be implemented at ferroalloy EAFs, the conditions presented (including the concentrations of NO_X emissions) at ferroalloy EAFs would not reduce NO_X sufficiently to achieve anywhere near the proposed NO_X emissions limit under the proposed rule; meaning, the proposed NO_X emissions limit of 0.15 lb/ton product cannot be achieved without add-on controls, but no add-on controls exist (for EAFs) that could achieve that rate. The commenter provides the following reasons why SCR/SNCR systems are technically infeasible at ferroalloy EAFs:

(1) SCR requires a stable gas stream to effectively reduce NO_X, including stable flow rate, temperature, and NO_X concentration. For example, according to the commenter, ferroalloy EAFs are inherently reactive and temperatures can vary significantly at the top of the furnace, and therefore, thermal NO_X formation is not consistent;

(2) The inherent variability in the gas stream coming from a primary ferroalloy EAF makes it difficult to consistently deliver the proper reagent quantity and would prevent "ammonia slip;"

(3) There is no location (technically feasible) in the gas stream for an SCR at a ferroalloy EAF - *e.g.,* SCR cannot be located upstream of the baghouse because of the high particulate loading in the gas stream and SCR cannot be located downstream of the baghouse because the gas temperatures are too low to provide sufficient energy to initiate the catalytic reaction - baghouse range between 230˚F and 400˚F compared to 500° and 1,000°F needed for the catalyst to be effective;

(4) NO_X emissions factors are as high a 65 lb/ton metal for primary ferroalloy EAF operation – *i.e.,* to achieve the proposed NO_X emissions limit of 0.15 lb/ton would require up to 99.8 percent removal of NO_X;

(5) The inability to maintain stable NO_X concentrations generated from thermal NO_X formation would significantly impair the effectiveness of NO_X control by preventing maintenance of proper reagent addition rate at the SNCR; and

(6) SNCR requires even higher temperatures compared to SCR across a relatively narrow temperature range (1600˚F – 2000˚F) to operate effectively, and these high temperatures do not exist upstream or downstream of the baghouse at a ferroalloy facility.

As additional support, the commenter summarizes the PSD permit finding for the Sinova facility as follows:

- SCR and SCNR controls are not technically feasible options and have never been achieved in practice at a ferroalloy facility;
- RACT is intended as the minimum level of control that ozone nonattainment areas must achieve for existing sources and requires less effective control than BACT; nonetheless, even BACT did not identify add-on NO_X controls as feasible options;
- BACT established a NO_X control limit 300x less stringent at a new (non-retrofitted) ferroalloy facility as compared to the NO_X emissions limit under the Proposed Rule for new and existing EAFs under a less stringent standard;

The commenter further asserts that Sinova's inability to obtain proposals for SCR/SNCR from vendors is consistent with EPA's inability to evaluate a single ferroalloy EAF in its Screening Assessment, and further confirms that the EPA's proposed regulation of ferroalloy manufacturing facilities has no factual or scientific basis;

Commenter (0345) argues that ferroalloy manufacturing operations differ significantly from the iron and steel operations the proposed rule is based on, and if the EPA intends the proposal to apply to independent ferroalloy manufacturing operations, the proposal does not support those claims – *i.e.*, does not provide any basis for doing so. The commenter observes that while the proposed FIP's emissions limits on EAFs assumes the use of SCR or SNCR technology, the commenter underscores the point that EAFs used in ferroalloy manufacturing operate very differently than those used in iron and steel manufacturing – in ways that either dramatically increase the cost of SCR/NSCR (to exceed beyond the assumed $7,500 cost-effectiveness threshold) or preclude those technologies entirely. Specifically, the commenter notes the following:

- SNCR and SCR control technologies require high-temperature reaction zones.
- EAFs used in ferroalloy manufacturing are open furnaces; adding furnaces discussed in the background documents used to establish limits are closed furnaces, which have a very different emissions profile.
- The dilution air that enters into an open furnace system complicates the treatment of exhaust gases, due to the reduced concentration of NO_X.
- Different emissions profiles are reflected in the different permit limits for ferroalloy manufacturing facilities.
- The TSD indicates that the EPA bases its proposed 0.15 lb/ton limit on "potential use of low-NO_X burners and selective catalytic reduction." [TSD at 43]. EAFs used in ferroalloy manufacturing do not use any on-site combustion (like low-NO_X burners), however; instead, the required electricity is supplied from the local power company.

Commenter (0359) adds SCR is not a preferred control technology in types of applications (like EAFs) where the pollutant load concentration, exhaust temperature, and flow rates change regularly with a batch type process. Additionally, the commenter mentions that the emissions during charging or other times the furnace roof is open are controlled through the use of a canopy hood that also evacuates to the EAF Baghouses. According to the commenter, this exhaust stream will also, based on the nature of the operations within the Melt Shop at the time, have a varying pollutant load concentration, exhaust temperature, and flow rates which is unsuitable for an SCR. The commenter claims, based on the intermittent usage characteristics of the smaller heaters within the melt shop (ladle/tundish preheaters) and the fact that the emissions of these units are vented within the melt shop itself, any use of an SCR would have to be based on collection of NO_X emissions from the canopy hood, which is not practical. The commenter explains that this is similar to the annealing furnaces located outside the melt shop. The commenter adds that these smaller units, often multiple sources less than 10 mmBtu, also vent individually within a building, precluding the practical use of SCR.

In a similar comment, commenter (0359) stress that the primary pollutant of concern (see 40 CFR 60, subpart AAa and 40 CFR 63, subpart YYYYY) from an EAF is PM, and the use of the EAF Baghouses require the temperature of the exhaust stream to be around 300°F. The commenter acknowledges that an SCR would have to be located downstream of this baghouse to properly control NO_X and prevent damage from particulate fouling. Therefore, according to the commenter the use of an SCR would require the exhaust stream to be reheated after passing through the baghouse. The commenter maintains that heating a high-volume exhaust stream like one from an EAF to proper temperature for SCR control would result in collateral emissions of NO_X from the additional fuel that would have to be combusted to provide the heat.

Commenters (0405, 0416), at large, argue that the use of SCR (and the proposed emissions limit of 0.15 lb/ton) on an EAF is not technically feasible. Foremost, the commenters mention the use or purpose of EAF – a batch process used to melt steel scrap and returns from the mill by use of an electric arc. The commenters add that scrap is charged through the open lid of the vessel, and when closed, an arc is drawn utilizing the carbon electrodes in the vessel. The commenters explain that the heat of the arc melts the scrap and generates off- gases which are drawn through an opening in the furnace lid. According to the commenters, the evacuation rate is controlled to keep the furnace at a slight negative pressure to prevent loss of fugitive emissions while not drawing ambient air into the vessel. The commenters further note that gases pass through refractory lined duct and the CO is oxidized by introduction of ambient air through an air gap in the duct, which is referred to as direct evacuation control – that allows the furnace lid to be removed and the furnace to be rotated for metal tapping. Furthermore, that commenter explains that during a heat, the gases are cooled by a water-cooled duct and combined with the gas volume exhausted from the shop canopy hood. The commenters note that NO_X formation in the EAF vessel is minimal because the furnace is maintained at a low negative pressure and minimal ambient air is introduced. The commenters suggest that supplemental heat can be supplied by oxy-fuel burners which combust natural gas and/or carbon fuel with elemental oxygen; further adding that the burners do not use air for combustion and NO_X is therefore not formed. The commenters maintain that NO_X potentially can be formed by the combustion of CO in the air gap; nevertheless, air ingress is controlled, and the final flue gases have minimum excess oxygen. Additionally, the commenters note that direct evacuation control gases are combined with the canopy hood gases and filtered in a negative pressure fabric filter before release to the atmosphere; noting that typical filter gas volumes are between 750,000 and 1,500,000 actual cfm at between 170°F and 240°F (NO_X concentration levels are typically around 50 ppm). The commenters state the additional reasons that the application of SCR on an EAF is not technically feasible:

- The wide variation in gas temperature in the direct evacuation control system (fluctuating from ambient to 2100 F) during the batch process heat cycle would thermally stress the catalyst substrate, sintering the matrix.
- The low NO_X concentration in the direct evacuation control system would result in low removal efficiency.
- PM in the gases is abrasive and would limit the efficiency of the system, and the metals in the particulate would poison the catalyst.
- Placement of the SCR after the final shop particulate control device, *i.e.*, baghouse, is not technically feasible due to low temperatures and would require wasteful combustion of a significant amount of natural gas to reheat the large volume of gas to the SCR activation temperature. This would result in the formation of additional NO_X and other pollutants, including GHGs.
- There have been no successful SCR applications on an EAF. Accordingly, SCR vendors have no experience in specification of SCR design or catalyst formulation and no stated removal efficiency can be guaranteed or even theorized without actual data from a successful EAF application. The EPA has not provided any example of a successful application of SCR at an EAF.

Commenter (0416) asserts that NO_X control technology to the extent necessary to achieve the identified NO_X emissions limits (0.15 lb/ton steel) is not technically feasible for nearly all of the identified iron and steel emissions units (*e.g.*, as the cost per ton of NO_X reduced is substantially higher than calculated by the EPA), and the EPA's information in the docket does not provide any support for its purported technical feasibility conclusions. Furthermore, the commenter recalls that numerous RACT and BACT and LAER determinations for the steel industry have been approved by the EPA that have consistently concluded that installation of SCR on an Electric Arc Furnace (EAF) is technically infeasible.

Commenters (0518, 0549) insist that the EPA revisit its list of available emissions controls and conduct a proper feasibility analysis of controls across the sectors – based on current economics and realistic timeline for installation. The commenters maintain that the EPA's proposed emissions control equipment for facilities are infeasible – that is, the type of control the EPA proposes were not designed for and could not be installed on the unit. To illustrate, the commenters note that the EPA presumes EAFs, under the Tier 1 non-EGU NAICS 3311, will achieve a 40 percent reduction using SCR; however, this equipment has never been used on an EAF before nor has this control been demonstrated to be feasible. Likewise, at a modern cement kiln under the Tier 1 non-EGU NAICS 3273, the SCR would need to be placed after a baghouse that runs at a much lower temperature, resulting in the exhaust gases needing to be reheated (after the baghouse and before entering the SCR). The commenters argue that re-heating the kiln exhaust gas is energy intensive (natural gas fired), more costly (estimated to be $16,000 per ton of NO_X) than EPA has assumed, and counterproductive to greenhouse gas reductions efforts. More specifically, the commenters point out that the EPA evaluated SCR technology on coal-fired boilers – not cement kilns, which have increased sulfur and PM concentrations and lower flue gas exhaust temperatures, which make SCR technology challenging to operate. The commenters conclude that these examples highlight the need for EPA to evaluate fully across the non-EGU sources – and with updated data – which controls are feasible, before imposing new restrictions on non-EGUs.

Commenter (0798) tailors comments specifical to EAFs, because those are the only furnaces used by the commenter with a PTE more than 100 tpy of NO_X, and thus are the only units the Proposed Rule would apply to, since, according to the commenter, the proposed rule only aggregates emissions for the purposes of applicability in the case of a BOF Shop (which would not apply to an EAF given that EAFs and BOFs are different processes). The commenter adds that if EPA changes course in the final rule and expands the applicability of the limits in the Proposed Rule, they reserve the right to challenge such applicability and/or provide additional comments regarding any other such units EPA may extend applicability to.

Commenter (0798) disagrees that pollution controls, which the commenter points out have never been demonstrated in the iron and steel industry, are feasible and effective—so effective that they will result in substantial (40 percent to 50 percent) reductions in emissions beyond current best-performing sources. To illustrate their point, the commenter highlights that the EPA assumes that SCR is broadly available to reduce emissions from numerous sources, including blast furnaces and BOFs, and coke ovens, by as much as 50 percent from currently permitted limits, along or in combination with low-NO_X burners. However, the commenter underscores the point that there is nothing in the record to show that SCR has been installed on any of these emissions sources before, nor that doing so would result in the level or amount of emissions reductions EPA projects. The commenter points out that the reference article from the Arid Zone Journal of Engineering, Technology and Environment does not indicate that this is based on any real-world application, instead, cites only studies of the use of SCR for other sources. Moreover, the commenter questions the achievement of reductions at blast furnaces using "burner replacement," particularly, since low-NO_X burners were recently eliminated as a control option for blast furnace stoves fueled primarily by blast furnace gas.

The commenter (0798) recalls that the EPA acknowledges that the emissions limits for the iron and steel industry, including but not limited to furnaces, are below anything that has ever been achieved in the industry, expressly noting that the EPA reviewed permits to find the best performing sources, then requires reductions below what the most stringent existing permits require. The commenter explains that the only basis EPA provides for assuming that such reductions are possible is that the EPA "[a]ssumes 25 percent reduction by SCR" for steel mill EAFs, but the commenter points out that none of EPA's underlying documentation or data ever evaluate the technical feasibility of retrofitting SCR on steel mill EAFs, or the level of emissions reductions available from such a retrofit on an EAF.

With regard to the technical feasibility of installing an SCR on an EAF, the commenter (0798) states that the proposed rule does not point to any steel mills that have successfully installed SCRs on an EAF, nor is the commenter aware of any EAF facility to have successfully installed the control equipment. To further illustrate their point, the commenter briefly discusses the PSD review process underwent by the BRS facility in 2013, and later in 2021.

The commenter notes that as reflected in these applications (as well as in other PSD permits issued to EAFs in recent years), the use of the control equipment SCR was eliminated from consideration, because the technology is not technically feasible. Similarly, the commenter suggests that there is no information available that indicates NO_X emissions controls have been installed on EAF's or that suitable controls are available." The commenter provides the following three recommendations:

(1) EPA abandons its own edict that each unit must be assessed "on an individual basis to determine whether SCR is a feasible control technology"—EPA has not provided any feasibility analysis for steel mill EAFs generally, let alone for each EAF "based on its site-specific characteristics." In fact, the commenter highlights that the very document which the Proposed Rule cites as the basis for concluding that SCR will reduce emissions from EAFs expressly states that, "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."

(2) EPA has not provided any justification for its newfound belief that SCR is a feasible control for steel mill EAFs – *i.e.*, the Proposed Rule does not detail what if any relevant change to EAF or SCR technology has occurred since 1994 which would make SCR technically feasible NO_X control for an EAF.

(3) EPA has historically refused to adopt unproven applications of technologies even in other programs where EPA has broad authority to require NO_X reductions.

With regard to emissions reductions expected, according to the commenter (0798), the non-EGU screening assessment never assessed emissions reductions associated with installation of an SCR at a single EAF, even though the Proposal purports to base its assumption of "reductions of 20 to 50 percent" for iron and steel mills "on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment." The commenter adds that the newer facilities (*e.g.*, EV facilities that have undergone BACT review in recent years) low NO_X burner technology is already in place.

The commenter (0798) states that the EPA fails to clarify the discontent – rationale for assuming NO_X emissions can be reduced on an EAF by as much as 50 percent. The commenter further notes that because the Proposed Rule's assertion that steel mill EAFs can achieve required emissions limits by installing SCRs or other technologies is unsupported by the screening assessment on which EPA purports to base its assumptions, the Proposed Rule is arbitrary and capricious since "the agency has failed to 'examine the relevant data' or failed to 'articulate a rational explanation for its actions.'" Nor does EPA, according to the commenter, attempt any facility or emissions unit level analysis of whether the technology required would actually reduce NO_X emissions – a notable contrast to prior rulemakings. The commenter states that the EPA's failure to conduct emissions unit-specific assessments of technically feasible emissions reductions for the non-EGUs EPA subjects to the emissions limits under Proposed Rule is particularly arbitrary in light of EPA's treatment of California's EGUs, which EPA proposes to exempt from the Proposed Rule based on a facility or emissions unit specific analysis that significant additional potential emissions reductions from the relevant EGU would not be technically feasible, an analysis EPA refused to conduct for any other facility nationwide.

The commenter (0798) expresses uncertainty that assumptions made about EAF lb/ton limits were based on limits currently achieved in practice. To illustrate, the commenter points out that the EPA identifies, in the proposed FIP, which facility permit or state RACT limit was reviewed and used as a basis for identifying a lb/ton efficiency limit currently achieved for that furnace type – a limit that is presumed to be lower by use of SCR; however, the commenter notes that does not identify any facility permit by name, instead the Proposed Rule vaguely states that the EPA found “Example permit limits at around 0.2 lb/ton.” According to the commenter, because integrated iron and steel facilities generally use Blast Furnaces and BOFs and not EAFs, and ferroalloy facilities do not use EAFs, suggests that the EPA looked at non-EAF units as a basis for setting the NO_X emissions limits for EAFs in the Proposed Rule. The commenter (0798) states that to the extent that EAFs at a given facility have an emissions rate higher than 0.2 lb/ton identified by the EPA, then the SCR control technology proposed by the EPA to justify the assumption that the proposed limits are possible to achieve, would have to be shown to be capable of reducing emissions by greater than 25 percent.

Furthermore, the commenter (0798) states the EPA was able to avoid considerations of unit specific feasibility in prior good neighbor rulemakings – and simply focus on “fleet average” characteristics – because all prior rulemakings were based on emissions trading schemes with statewide budgets, rather than imposing emissions limits on a unit specific basis as EPA now proposes to do for the first time ever under the Proposed Rule. The commenter insists that the EPA cannot evade unit specific feasibility analysis by merely pointing to past rulemaking while ignoring the fundamental difference between an emissions trading program and command-and-control emissions limits it seeks to impose on the iron and steel industry, which is especially important where proposed limits begin reaching or exceeding limits of technological feasibility. According to the commenter, if EPA wishes to impose emissions limits on a unit specific basis under the good neighbor provision of the CAA, at a minimum, the EPA must address the technical feasibility of emissions limits on an emissions unit basis.

Commenter (0798) discusses/summarizes in detail a number of reasons – Technical issues that could either render installation infeasible or would prevent the SCR from generating the emissions reductions it may have in other contexts – why EAF have not demonstrated SCR controls in practice. [Note that the commenter provides a memo as an attachment, from Black & Veatch an engineering firm with actual experience designing and installing SCR systems at EGUs, as support, and includes more detailed and technical critiques of the technical and economic feasibility of installing SCR].

The commenter (0798) explains that EAFs are a fundamentally different process than the EGUs at which SCR has been demonstrated – *e.g.,* unlike the relative continuous process associated with EGUs, an EAF is a batch process, an important factor to consider knowing that an SCR requires stable gas flow rates, NO_X concentrations, and temperature to effectively reduce NO_X. Furthermore, the commenter states that an EAF is not a combustion process, but instead relies on electricity to melt metal scrap, meaning that the emissions profile of the process is different than the emissions profile associated with the SCR. The commenter further explains that the combustion of fossil fuels, notably including sulfur dioxide and many metals and materials are incompatible with the SCR, because certain elements present in EAF emissions, such as iron, arsenic, sodium, potassium, nickel, chrome, lead and zinc and potentially others, can react with platinum catalysts to form compounds or alloys which are not catalytically active – *i.e.,* result in "catalytic poisoning."

Furthermore, the commenter (0798) notes that any solid material in the gas stream can form deposits and result in fouling (occurs when solids obstruct the cell openings within the catalyst) or masking (occurs when a film [to prevent contact] forms on the surface of catalyst over time) of the catalytic surface. The commenter maintains that it is infeasible to install an SCR upstream of the baghouse which collects these metals and PM, because the SCR catalyst would be bombarded with all these elements which it is not equipped to handle; reducing its efficiency and at best requiring frequent changing of the catalyst. Furthermore, the commenter notes that there may be potential for entrained moisture and or condensable emissions that could be detrimental to the catalyst if a leak were to occur from the tubular section or when temperatures and moisture conditions are unfavorable during cycling of systems. The commenter concludes that the ability of poisoning and fouling to make SCR technically infeasible is not theoretical.

The commenter (0798) explains that an SCR requires operating temperatures between 480°F (250°C) and 800°F (427°C) of the gas stream at the catalyst bed, to carry out the catalytic reduction process; but these temperatures are incompatible with the commenter's BRS/EV facilities baghouses which requires the inlet to be dropped down to below 266°F (130°C) to avoid catching fire; representing the maximum peak temperature at the spark arrestor prior to the baghouse, with temperatures at other times being far lower accordingly.

Furthermore, the commenter (0798) claims that cooler gas makes the baghouse more effective – the cooler the gas, the more the metals convert from gas to solid phase preventing them from bypassing the baghouse. In order to regulate the inlet temperature to the baghouse, the commenter states, that their BRS or EV facilities have cooling systems for the ductwork between each EAF and the associated baghouse – cooling systems that are incompatible with installing an SCR.

The commenter (0798) continues to explain that the only point at which the temperature is not below the operating range of an SCR is the very opening of the EAF duct prior to cooling the flue gas, but that is above the temperature for an SCR (around 1,200 to 1,300°F), and any attempt to cool the temperature at the entrance to the EAF duct, such as through the use of tempering fans, would increase the flowrate through the duct and into the baghouse, which also raises a host of feasibility issues. In addition, the commenter notes that the tempering fans, SCR and other new equipment would increase electrical demand at the BRS/EV facility, decreasing efficiency and significantly increasing indirect emissions *e.g.,* NO_X, SO_2, PM, greenhouse gases, etc. associated with the substantial increase in electricity consumption to operate the SCR and associated equipment and additional flue gas cooling systems, and that assumes that sufficient electric capacity and related equipment to transfer such energy loads is available or otherwise is not in excess of current design capacities. The commenter underscores the point spatial constraints can pose obstacles to making an SCR installation work – *e.g.,* the space between the EAF and the baghouse is limited, and likely would prevent an SCR and associated retrofit equipment being installed anywhere upstream of the baghouse, much less by the entrance to the EAF duct. Likewise, the commenter notes that there are also spacing, and structural design and support limitations that may limit the feasibility of installing an SCR into the stack post-baghouse – *e.g.,* concrete infrastructure post-baghouse including stack foundation and blower house are substantial installations and the existing as-built design restricts access to the exhaust flow. The commenter stresses that there is insufficient space between the ID fan and the stack for the SCR, let alone the booster fan that would likely be necessary to maintain pressure, so any installation would require new structural supports, stack breaching, and the new ductwork would require multiple turns that would increase the pressure drop the booster fan would have to provide, and increase power demands, further exacerbating power capacity issues.

Commenter (0798) asserts that installing SCRs on EAFs would risk significantly increasing emissions, such that the emissions reductions anticipated would not be possible, or may be much smaller than estimated by the EPA. This is because the flue gas exiting the baghouse is typically below 200°F, far below SCR operating range. That means that the flue gas would have to be heated post-baghouse by a significant temperature (at least 300°F in a short period of time), requiring significant additional energy, likely from natural gas combustion and associated electricity needs, which in turn would increase the very NO_X emissions the SCR is designed to control, as well as increasing GHG, VOC, CO, SO_2 and PM emissions. These increases may be significant as described in the following section, especially compared to the relatively low NO_X reductions an SCR would accomplish even if able to run efficiently. In addition to any increased emissions caused directly by new combustion sources and indirectly due to increased power consumption, the commenter adds that unreacted ammonia would also be emitted to the environment as ammonia slip, along with the formation of ammonium salts can readily foul the catalyst section, resulting in reduced efficiency and increased back pressure. And installation after the baghouse system, according to the commenter, means that these ammonia and ammonium salt emissions would be completely uncontrolled, creating potential compliance and attainment concerns with the $PM_{2.5}$ emissions limits and NAAQS, respectively. The commenter explains that on the other hand, installation of SCR prior to the baghouse system would contaminate the fly ash in the baghouse with ammonia, and as EPA has recognized, “the ability to sell the fly ash as a secondary product is affected by its ammonia concentration.” The commenter states that if this compromises BRS’ ability to recycle its baghouse dust by resale to reclamation, recycling, or reuse facilities as is BRS’ current practice, then the installation of SCR would create a new unrecycled hazardous waste stream. Furthermore, the commenter points out that the EPA has also recognized, “ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heater, ducts, and fans” thus endangering the existing pollution control system. Additionally, the commenter clarifies that even if SCR technology could be installed post baghouse, the SCR would have issues with catalyst poisoning due to sulfur, as SO_2, reacting with the SCR regardless of the placement of the SCR (impeding technical feasibility) unless desulphurization technology can also be installed (which would entail both its own set of technical feasibility issues in addition to significant additional costs not considered by the EPA). According to the commenter, stack testing at their BRS facility shows a NO_X concentration in flue gas near the lower limit of what concentration can be controlled by an SCR. The commenter states that according to EPA’s own analyses, “Low NO_X inlet levels result in decreased NO_X removal efficiencies” an SCR is generally only expected to control 70 percent of emissions at a ppm loading as low as 20 ppm. And we are unaware of any vendor that will guarantee removal efficiency at all much below 5 ppm NO_X – limitations on control efficiency CE that are further exacerbated by the temperature issue, since temperatures on the low end of SCR operability also significantly decrease SCR efficiency as compared to higher temperatures.

The commenter (0798) believes that SCR is infeasible from an emissions reduction perspective, because the smaller decreases in NO_X associated with SCR at a unit with only a few hundred tons of potential emissions NO_X could be significantly offset or even swallowed by electrical consumption of the SCR and its related equipment (indirect emissions) as well as increased emissions from flue gas heating or the increased indirect emissions associated with an increase in energy consumption associated with flue gas cooling equipment, both of which would significant heat/electrical input due to the conditional dynamics required in such short distances. The commenter references the engineering review conducted by Black & Veatch, stating in this review, the exhaust gas temperature from an EAF, prior to the dedusting baghouse / after the baghouse, is in the vicinity of 200°F, thus requiring additional equipment to be installed to raise the exhaust gas temperature by at least 300°F to reach the minimum operability range of 500°F for an SCR, as would be required for just 50 percent NO_X removal efficiency; requiring the installation of a heating devices, which will consist of the installation / operation of a natural gas fired burner(s). The commenter provides the following equation to determine the amount of energy required to heat the EAF dedusting exhaust air by 300°F:

- British Thermal Units (BTU) Output = Temperature rise multiplied by (X) cubic feet per minute X BTU per pound per °F X the density of air at 200 °F X 60 minutes per hour.
    - Temperature rise required is 300°F.
    - Exhaust gas flow from an EAF is on average approximately 1,300,000 standard cubic feet per minute (SCFM) from a dedusting system. Actual flow rate (actual CFM) does vary based on temperature and other parameters.
    - Specific heat of air at 200°F is 0.24 BTU per pound per °F.
    - The weight per cubic foot of air is 0.061 (pounds / cubic foot)(lbs/ft3)).
- BTU Output = 300°F. X 1,300,000 cubic feet per minute X 0.24 BTU per pound, per °F X 0.061 lbs/ft3 X 60 minutes / hour = 342.5 mmBtu/hour.

The commenter (0798) explains that to generate the 342.5 mmBtu/hour needed to heat the exhaust gas by 300°F, and assuming the heating value of natural gas is 1,000 BTU per cubic foot, you would need 342,500 cubic feet per hour of natural gas; adding that combusting that additional natural gas will cause a release of NO_X emissions (among other pollutants) during the process of combusting that natural gas in the heating burner(s).

Note that commenter (0798) points to AP-42 emissions factors as a tool for calculating the amount of NO_X emissions that can occur when combusting 342,500 cubic feet of natural gas. The commenter defines an emissions factor and references Section 1.4 of AP-42, reminding that this section provides emissions factors for quantifying the emissions of NO_X, as well as other regulated air pollutants based in the combustion of natural gas expressed in either pounds per mmBtu or pounds per standard cubic foot of natural gas combusted. The commenter also references Tables 1.4-1 and 1.4-2 noting that they provide emissions factors for various regulated air pollutants and provide a summary table of those factors as part of their remarks. The commenter adds that to estimate the potential emissions of the above listed regulated air pollutant, the emissions factor expressed in pound per million cubic standard feet of natural gas is multiplied by the quantity of natural gas combusted in an hour to get pounds of that air pollutant per hour and then the amount of natural gas consumed in a year to get pounds per year or commonly expressed as tpy. The commenter provides (in table format) an estimate of the additional air pollutants that would be released in the atmosphere based on installation of natural gas burners to heat the EAF exhaust air by 300°F, to allow for SCR to operate at even minimum effectiveness.

It is important to note, that the above estimated emissions of regulated air pollutants are additional amounts of these air pollutants that would be generated / released to the atmosphere based on the required heat the EAF dedusting exhaust gas by 300°F to allow for SCR to operate. The commenter (0798) adds that an additional 250°F raise in the temperature would be required so that the SCR could operate at the optimum temperature, which is around 750°F in NO_X emissions levels. The commenter states that the amount of energy required to raise that temperature would require the natural gas volume to be increased by almost a factor of two. In that case, according to the commenter, the projected emissions rates would also increase by a factor of approximately two. The commenter notes that this is an estimate of the increased air pollutant emissions per EAF and would thus need to be multiplied by each EAF to which SCR is applied which for the case of the BRS/EV facility, would be four times to reflect four EAFs.

The commenter (0798) asserts that the Proposed Rule would decrease the permitted lb/ton NO_X rate for each of the BRS/EV EAFs by up to 50 percent by reducing the current permit limit of 0.3 lb/ton to the Proposed Rule limit of 0.15 lb/ton – at a presumed capacity of 250 tons/hr for each EAF, times 3,672 hours per ozone season, that represents a reduction of up to 137,700 lb (*i.e.*, 68.85 ozone season tons) per EAF. The commenter proclaims, when comparing these maximum potential reductions (68.85 ozone season tons) to the potential NO_X increases (87.5 ozone season tons), it appears that the changes to an EAF dedusting exhaust gas temperature necessary to enable SCR to function could be even higher than the potential NO_X reductions achieved by installation of an SCR units at the BRS/EV facility.

Additionally, the commenter (0798) argues that in addition to emissions increases associated with installation of natural gas fired burners needed for EAF dedusting exhaust gas heating, the ammonia slip associated with SCR installation would cause the release of ammonia emissions (in the form of PM) from each EAF, which are typically not associated with dedusting exhaust gases. The commenter defines slip as being a situation where not all of the ammonia used in the SCR system chemically reacts to reduce the presence of NO_X in the dedusting exhaust air. The commenter highlights that the EPA's own estimates suggest that SCR can be associated with 2 to 10 ppm ammonia slip, and even a well-functioning SCR would have ammonia slip of 2 to 5 ppm, with ammonia slip increasing as catalyst activity decreases, as it might be expected to occur given the range of feasibility issues entailed in installation on an EAF, including the high temperature variability and airflow variability, and poisoning/fouling/plugging issues.

The commenter (0798) outlines an equation that would provide a general estimate of the quantity of ammonia slip emitted per hour; finding that, assuming operation only during the ozone season, 17.238 lbs/hr x 8760 hrs/year x 5/12 ozone months/year x 0.0005 ton/lb = 31 tons of ammonia per ozone season per EAF. Additionally, the commenter asserts that the installation of a baghouse downstream would have resulted in an increase in $PM_{2.5}$ emissions. The commenter references studies that suggest reducing ammonia emissions to reduce condensable PM is more cost effective than NO_X reductions. The commenter warns, however, that if installed upstream of the baghouse, any portion not emitted would contaminate the baghouse dust that is currently recycled/reclaimed by a third party, potentially creating a new and significant hazardous waste stream.

Commenters (0237, 0303) express their concerns that the ammonium salts formed due to NH3 slip could be viewed as a PM10 increase; noting that NH3 slip is a tremendous issue for CA sources, because facilities in CA are required to report EPA Method 5 “back half” PM emissions. Commenters (0237, 0303) highlight that SNCR technical feasibility and cost effectiveness is a function of the NH3 slip limit set, and to the extent that kiln modifications are needed to achieve better mixing for improved SNCR performance and lower NH3 slip, these could increase the SNCR total cost ten-fold or more.

The commenter (0798) concludes that combined, the increased NO_X emissions from dedusting exhaust air heating and ammonia (*i.e.*, PM) emissions from ammonia slip would negate any environmental value/benefit of the SCR, given the equivalent or smaller amount of NO_X the SCR would be capable of reducing from each EAF – thus, demonstrating that SCR installation is not a technically feasible means of decreasing NO_X from EAFs by ~50 percent as would be required to meet the limits in the Proposed Rule and requiring SCR in the face of these realities is arbitrary and capricious.

Commenter (0504) states their belief that the EPA miscalculated how quickly new controls could be deployed at EAF facilities. First, the commenter observers that the proposed FIP does not clearly identify the control strategy the Agency expects to be utilized to control NO_X from emissions units typically present at EAF steel facilities. The commenter briefly describes inconsistencies between the preamble to the proposed FIP and, for example, the Proposed Non-EGU Sectors TSD, in recommending proposed NO_X limits for LMS. The commenter asserts that the EPA has no basis to speculate as to the time necessary to design, purchase, install, and operate these indeterminate control strategies. The commenter maintains that it is premature for EPA to request comment on the timing for installation of controls, unless and until EPA conclusively identifies the control strategy to be installed. The commenter explains the currently, potentially impacted stakeholders have no premise on which to base engineering analyses; design, construction, and permitting schedules, or vender surveys, nor can the industry expected to hire a consultant to fully assess the technological feasibility, cost-effectiveness, and installation timing of controls that the EPA has not yet conclusively identified. The commenter asks that the EPA correct inconsistent control assumptions for emissions units at EAF steel facilities, and must, not only update its conclusions regarding technological feasibility, cost-effectiveness, and installation timing, but must publish those updated analyses and allow for additional public comment.

In a similar comment, commenter (0504) asserts that the EPA has no basis to estimate timelines for SCR at emissions units at EAF facilities, because the Agency has never assessed SCR installation timelines for any of these units before. Therefore, the premise, according to the commenter, that SCRs can be installed at any EAF facility within the given, limited timeframe (three years) is impractical and unsupported. The commenter further argues that SCR controls are more common on EGUs, whom have decades years of experience installing/retrofitting these controls and units. This estimate of SCR installation timing was derived from EPA's more extensive analysis of SCR installation times necessary in the EGU industry. But SCR is a far more common control at EGUs, and EGU operators have decades of experience installing, calibrating, and operating SCR.

Response:

As discussed in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for EAFs.

10.6.2.2 Technical Feasibility of SCR on Submerged Arc Furnace (SAFs)

Comments:

Overall, commenters (0298, 0514) assert that SAFs are distinct from EAFs covered by the proposed rule and suggests the emissions limits imposed on EAFs would not be appropriate for SAFs. The commenters underscore the point that are not aware of post-combustion controls identified in the Proposed Rule for EAFs being demonstrated in practice at either EAFs or SAFs, and recent BACT determinations specific to new silicon production facilities using SAFs have confirmed that post-combustion controls are not technically feasible. To illustrate the point, the commenters describe the permitting process at the Sinova Silicon LLC facility, which also dismissed SCR as not technically feasible for an SAF on the grounds that "SCR systems are frequently used to reduce NO_X emissions from combustion sources but have never been applied to reduce NO_X emissions from an SAF. The commenter (0514) notes that SNCR, likewise was dismissed as technically infeasible for the same reasons, with the additional rationale that temperatures necessary for SNCR only exist upstream of an SAF baghouse, and injecting ammonia or urea upstream of the baghouse could cause the baghouse to plug and may negatively impact the quality of the silica fume collected. Commenter (0298) extracts a few statements from the issued permit on the feasibility and costs of SCR and SNCR systems on SAF – *e.g.,* SCR nor SNCR has never been applied to reduce NO_X emissions from an SAF, and therefore, costs and benefits are largely unknown. Similarly, commenter (0514) notes that vendors and/or manufacturers of SCR systems used to reduce NO_X emissions from large coal-fired power plants were contacted but were unwilling to provide a cost estimate for application of SCR to an SAF with performance and reliability guarantees, because it has never been done before, and it is unclear how trace elements in the exhaust would interact with the catalyst, even downstream of the proposed baghouse used to capture silica."

Commenter (0298) asserts that BACT requires that a source adopt the most stringent level of control available to a source – a standard that is far more stringent than the Reasonably Available Control Technology (RACT) standard applicable to nonattainment areas addressed by the proposed rule. Thus, according to the commenter, even if it was lawful for EPA to apply BACT-level controls to address ozone transport nonattainment areas under the proposed rule, the EPA could not have substantiated a 0.15 lb/ton NO_X emissions limit based on installation of SCR/SNCR NO_X control technology.

Commenter (0514) states that they recently underwent an updated BACT analysis as part of a PSD permit revision to amend the short-term BACT emissions rates applicable to its SAFs. According to the commenter, this review dismissed SCR as technically infeasible for SAFs due to the high variations in temperature and flowrates throughout the SAF batch process cycle and poisoning and fouling of the catalyst due to compounds and alloys in the SAF flue gas. Additionally, the commenter points out limitations on space for an SCR at the commenter's MS Silicon facility would preclude installation of an SCR. Finally, the commenter mentions that the flue gas temperatures associated with their facility's (MS Silicon) operations are outside the range required for effective SCR operation. The commenter adds that other post-combustion NO_X control technologies/equipment, including SNCR were also rejected as technically infeasible for similar reasons. The commenter reiterates that other recent PSD reviews underscore the same conclusion.

Response:

As discussed in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for SAFs.

10.6.2.3 Technical Feasibility of SCR/SNCR on Coal-Fired Boilers

Comments:

Commenter's (0320) remarks focus on two coal-fired boilers located at the Westvaco facility. In general, the commenter argues that the Westvaco facility boilers should not be subject to ozone-season controls, because the boilers are already equipped with emissions controls, in an effort to comply with current and applicable federal regulations. The commenter concludes that the additional controls (SCR/SNCR) installed on the Westvaco boilers (as directed in the proposed FIP) would not result in significant emissions reductions but will likely add to operational costs. Existing efforts by the facility to reduce NO_X and other emissions from the two boilers, coupled with design features and operating characteristics of boilers (variable loads and temperature profile), according to the commenter, suggests that add-on NO_X controls are not necessary, and even if needed, are not feasible.

The commenter states that the two Westvaco coal-fired boilers are subject to federally enforceable limits and work practice requirements to minimize emissions, including the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial Boilers (also known as Boiler MACT). Additionally, the commenter notes that the two Granger coal-fired boilers are equipped with overfired air, electrostatic precipitators, and wet scrubbers and are currently subject to the Area Source Boiler NESHAP. According to the commenter, these four coal-fired boilers (and one large gas-fired boiler at Westvaco) have been evaluated for feasibility of additional controls under the Regional Haze Rule (both as part of Best Available Retrofit Technology [BART] analyses and recent four-factor analyses) and it has been determined that no additional controls are necessary. Regardless of those finding, the commenter notes that they are voluntarily converting their Granger coal-fired boilers to gas-fired boilers.

The commenter underscores the point that SNCR was developed for, and has predominantly been applied to, fossil fuel-fired utility boilers, and therefore, the effectiveness of SNCR on industrial boilers is typically on the low end of the control efficiency CE range. The commenter explains that unlike fossil fuel-fired utility boilers, industrial boilers experience variable loads, and the temperature profile in an industrial boiler is not as constant as that in a base-loaded fossil fuel-fired utility boiler.

The commenter reminds that SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must be between approximately 1,600 and 2,000°F for the chemical reaction to occur, and at low loads, temperatures may be below the optimum level required for achieving NO_X reductions. To illustrate the commenter notes that a boiler that experiences load swings according to production demands has a variable temperature profile, and to address this concern, the commenter suggests the need to install multiple levels of reagent injectors. According to the commenter, many industrial boilers are operated to track steam loads required for facility processes and are not operated under base load conditions as are utility boilers. The commenter worries, that if optimal furnace temperatures cannot be consistently maintained, the ammonia or urea injection rate needed to reduce NO_X emissions using SNCR will result in excess ammonia – that will combine with chlorides and sulfur in the combustion gas and result in increased corrosion on downstream metal and heat surfaces. The commenter also express concerns that chlorides in the gas stream will combine with excess ammonia to create condensable $PM_{2.5}$ in the flue gas; thereby, increasing $PM_{2.5}$ emissions. Similarly, ammonia emissions can also result in secondary formation of visibility impairing pollutants (nitrates and sulfates). The commenter continues to note that the variability of the SNCR temperature window is a critical issue, because of the consequences of ammonia injection outside this window. The commenter explains that below the temperature window, ammonia slip will occur due to incomplete reactions of the injected chemicals with the NO_X and above the temperature window the reducing chemicals could be combusted to form additional NO_X. The commenter claims that multiple injection levels must sometimes be installed to accommodate firebox temperature variability in boilers that swing to accommodate variable steam demand, and SNCR injectors must also be installed above any overfired air ports in the furnace, further limiting its application and effectiveness, according to the commenter, especially in boilers with shorter furnaces. The commenter contends that additional resources are required to operate an SNCR – water, power, and boiler fuel system because the SNCR process reduces the thermal efficiency of the boiler, which decreases the energy available for power or heat generation. The commenter adds that an economizer bypass may be necessary at lower loads to maintain the temperature window necessary for the reaction to occur, and as a result, additional fuel is required for the boiler to maintain the same steam output; resulting in additional emissions of other pollutants.

Similar to SNCR design and operations, the commenter recalls that SCR is a NO_X control technology that uses a catalyst to react injected anhydrous ammonia, aqueous ammonia or urea to chemically convert NO_X into N2 and H_2O, and the control employs a metal- based catalyst (vanadium or titanium), to increase the rate of the NO_X reduction reaction. The commenter explains that the flue gases flow into a reactor module containing the catalyst where the reagent selectively reacts with the NO_X. However, the commenter stresses that the reduction reactions used by SCR are effective only within a given temperature range where ammonia or urea is injected into the exhaust gases in a temperature range of 480°F — 800°F. For a large industrial boiler, the commenter notes that this temperature range is achievable between the generating bank outlet and the air heater or economizer. The commenter adds that if the SCR must be placed further downstream, a duct burner is necessary to achieve the proper temperature window or the air heater and economizer must be bypassed to keep the temperature of the flue gas elevated. According to the commenter, at the higher end of the temperature range, with the proper amount of reducing agent and injection grid design, SCR can achieve 90 percent reduction of NO_X given the right operating conditions. However, the commenter warns that ammonia slip – the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_X, can also occur. Moreover, the commenter notes that in practice, SCR systems operate at NO_X control efficiencies in the range of 70 percent to 90 percent for fossil fuel utility boilers (operating temperatures from 480 to 800°F, a temperature of at least 650°F is required to achieve the maximum control efficiency). Due to catalyst plugging problems associated with locating the catalyst at the economizer outlet of a solid fuel-fired boiler (*i.e.*, prior to the particulate control device), the commenter claims that an SCR system on our coal-fired boilers would have to be installed after an existing PM control device (to avoid a significant decrease in catalyst life and periodic plugging), and would require installation of a gas-fired flue gas duct burner to achieve the optimum reaction temperature (the flue gas temperature for industrial boilers is typically less than 480°F). The commenter insists that this would result in associated fuel costs and pollution increases, assuming there is adequate space to install the SCR reactor and the size duct burner needed to raise the temperature of the exhaust gas stream to the optimum temperature of 650°F.

The comment recalls that the EPA CoST model identifies only SCR and SNCR as feasible NO_X control technologies for coal-fired industrial boilers, as additional support.

Response:

See Section VI.C.5 of the preamble and Section 5.3.5 of this document for a response to these comments. The EPA also notes that the final rule applicability criteria for boilers do not include boilers from the commenter's sector, the Potash, Soda, and Borate Mineral Mining Industry.

10.6.2.4 Technical Feasibility of SCR on Gas-Fired Boilers

Comments:

Commenter (0320) states that the Westvaco facility operates several gas-fired boilers with NO_X emissions less than 100 tpy. The commenter maintains that retrofitting with LNB is generally feasible for gas-fired boilers but is not always without technical issues – *i.e.*, LNB burner conversion capability may be complicated by boiler age, configuration, and fire-box dimensions. The commenter further explains that when retrofitting an older existing boiler with LNB, FGR may also be required to achieve the desired level of NO_X reduction. Similarly, the commenter notes that while, retrofitting LNB on a small natural gas-fired package boiler with a single burner is fairly straightforward retrofitting a larger, older boiler that has multiple burners, however, can be more complicated, due to burner positions and the potential for overlapping flames to result in NO_X hot spots within the furnace. The commenter adds that to achieve low NO_X concentrations, a typical retrofit of a multiple burner boiler with LNB would also include FGR, some new ductwork, and a new fan, and would likely result in a NO_X level of around 50 ppm. The commenter recognizes that SCR has not been installed on many gas-fired industrial boilers outside of nonattainment areas, but agrees that it is technically feasible, assuming the exhaust meets the required temperature window. The commenter also recognizes that some natural gas boilers do not have adequate space to install an SCR reactor prior to the air heater or economizer, and the exhaust gas temperature following the air heater or economizer is typically less than 450°F. In these cases, the commenter states that a duct burner would be necessary for an SCR to be effective at reducing NO_X emissions from these boilers; raising the cost of controls and increase fuel use and GHG emissions.

Response:

As identified the preamble at Section V.C.2 and the *Final Non-EGU Sectors TSD*, the EPA anticipates that gas-fired boilers will be able to meet the final emissions limits by installing low-NO_X burners and FGR and has not found based on information available that SCR will be necessary to meet the emissions limits in the final rule. To the extent owners and operators of specific types of boilers can demonstrate that their unique circumstances will not allow them to meet the applicable emissions limit, the final rule allows for sources to apply for case-by-case emissions limits as explained in more detail in Section VI.C of the preamble.

10.6.2.5 Technical Feasibility of SCR on Four-Stroke Lean Burn Engines

Comments:

Commenter (0353) disagrees with EPA's assertion that for four-stroke lean burn engines, achieving a 1.5 g/hp-hr NO_X emissions limit is possible by using SCR emissions control technology systems; noting that most stationary engines used in the midstream sector are located at unmanned facilities, making the use of this technology impractical. First, the commenter believes that storing the ammonia needed for an SCR system at an unmanned facility raises significant safety concerns, particularly for an industry already struggling with trespassers and equipment theft. Second, the reliable operation of an SCR system requires monitoring ammonia storage, control, metering, injection rates, and leak detection systems. The commenter warns of the ammonia emissions from SCR systems – *i.e.*, ammonia slip, as well as the possibility of nozzle clogs, and stresses the importance of needing onsite detection and correction of these issues if/when they occur. The commenter suggests that the EPA account for factors, like staffing costs, when evaluating the feasibility of SCR system operations.

Response:

As explained in Section 2 of the *Final Non-EGU Sectors TSD* and Section VI.C.1, the EPA finds that four-stroke lean burn engines should generally be able to meet the 1.5 g/hp-hr emissions limit by installing SCR.

To the extent owners and operators of specific types of units can demonstrate that their unique circumstances will not allow them to meet the applicable emissions limit, the final rule allows for sources to apply for case-by-case emissions limits as explained in more details in Section VI.C of the preamble. Engines in Pipeline Transportation of Natural Gas also have the option of a facility-wide averaging plan.

10.6.2.6 Technical Feasibility of SCR on Pulp, Paper, and Paperboard Industry Boilers

Comments:

Overall, commenters (0343, 0557) assert that there are significant challenges and considerations that limit the feasibility of NO_X controls using SCR or SNCR in Pulp, Paper, and Paperboard Industry boilers, specifically boilers that combust biomass fuels (wood, wood residues/bark) either alone or in conjunction with fossil and other fuels.

Commenter (0343) implies that there are a number of operational and design characteristics that the EPA should be considering when determining the ease of usage of a SCR NO_X emissions control technology on boilers at pulp, paper and paperboard mills. First, the commenter notes that flue gas temperatures around 600°F are required for optimal SCR operation, with ranges reported between 480-800°F, which are achievable upstream of the economizer and the PM control device on industrial biomass-fired boilers. However, the commenter points out that high PM concentrations upstream of the PM control equipment (hot-side/high-dust) would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst by dominant metals in wood ashes (Na, P, Ph, Mn), which in turn requires downtime to clean and/or replace the catalyst. Additionally, the commenter states that plugging and fouling of the catalyst can occur due to larger amounts of fly ash generated by biomass burning (than coal, for instance). Second, the commenter suggests that most biomass-fired boiler temperature profiles are not appropriate for SCR. Specifically, the commenter mentions that installation of SCR downstream of the PM control equipment (cold-side/tail-end SCR) would render the gas stream too cold for effective reaction with the catalyst to reduce NO_X. The commenter reminds that the desired minimum temperature for SCR application to achieve 70 percent control is ~575°F, and flue gas temperatures at the exit of the PM control device in most pulp and paper industry co-fired units and strictly biomass-fired units are significantly lower than the range required for optimal control (between 300 and 400°F). The commenter further suggests that pressure drop requirements associated with the SCR system can render existing boiler fans unsuitable and create sizing concerns in existing, especially older, boilers. Finally, the commenter claims that size constraints, and the lack of piping runs and other real-estate can often make retrofitting an SCR system near the boiler impossible.

Commenter (0557) disagrees with EPA's assertion that SCRs would be installed on the majority of pulp and paper (P&P) boilers and would achieve a 90 percent reduction in mass emissions over 2023 uncontrolled emissions projections. The commenter suggests that the EPA has no basis for this assumption, because SCRs have not been installed or proven to be cost-effective for paper mill boilers.

Commenter (0557) claims that the installation of SCRs on pulp and paper products boilers (as well as other non-EGUs) will result in increases of GHG and criteria pollutant emissions, as well as increases in fossil fuel usage and emissions of ammonia – outcomes that should be considered by the EPA when considering control technology for boilers in pulp and paper products industry.

Response:

See Section VI.C.5 of the preamble to the final rule for the changes made to address boilers fired by alternative fuels and about the types of fuels covered by the final rule.

To the extent owners and operators of specific types of boilers can demonstrate that their unique circumstances will not allow them to meet the applicable emissions limit, the final rule allows for sources to apply for case-by-case emissions limits as explained in more details in Section VI.C of the preamble.

10.6.2.7 Technical Feasibility of SCR On Boilers in the Chemical Manufacturing Industry

Comment:

In a similar comment, commenter (0557) remarks focus on chemical manufacturing. More specifically, the commenter claims that the lack of specificity of industrial boiler applicability and compliance requirements is problematic for chemical manufacturers, partly because these facilities utilize boilers of many types in numerous applications (*e.g.*, used as control devices to process fuel vent gas). The commenter explains that application of SCRs require catalyst use that interferes with chemical operations and may hinder SCR operation and control efficiencies. The commenter suggests that the EPA further study the application of SCR requirements to chemical manufacturing in an effort to understand these nuances to properly craft a workable technology requirement in the Rule and achievable emissions reduction limitations.

Response:

See Section VI.C.5 of the preamble for an explanation of the clarification made to the applicability and definitions for boilers in the final rule.

10.6.2.8 Technical Feasibility of Add-on Controls in Iron and Steel Industry (General Comments)

Comments:

Overall, commenters (0221, 0409, 0416) assert that the proposed NO_X limits for the steel industry are technically infeasible, because the controls proposed in the FIP require consistent temperatures, flow rates, and concentrations which do not exist for many steel units. Furthermore, the commenters maintain that the proposed NO_X limits for the steel industry are unsupported, because EPA provides no justification that add-on controls are technically or economically feasible, and the proposed provisions lack the necessary engineering analyses to support these requirements and contradict past Best Available Control Technology (BACT) determinations established by permitting authorities.

Commenters (0221) claims that even if the use of the proposed control technologies by the steel industry were technically and economically feasible, they will not result in compliance with the proposed emissions limits, if considering a necessary compliance margin. According to the commenter, these are case-by-case determinations that need to be made with respect to each unit, as retrofitting existing equipment includes site specific factors that vary across a facility and the industry. The commenter suggests that they expect for a proposal of this significance that the EPA would perform a thorough evaluation using data for the selected control equipment being used at steel industry specific sources and calculate a 99-percentile upper predictive limit (UPL) to properly set an emissions limit to ensure that proposed limits are achievable.

Commenter (0376) disagrees with EPA's decision to proposed installation requirements of either SCR or SNCR at coke oven processes without adequately addressing technical feasibility. The commenter recognizes that in the case of boilers, controls like these have never been required before. The commenter cites the report titled, "Alternative Control Techniques Document – NO_X Emissions from Iron and Steel Mills," EPA-453/R-94-065 (September 1994)," as support; noting that the report found that there are many limitations and difficulties associated with, applying SCR controls, and some may be applicable only to new ovens". The report, according to the commenter, provided no details about the effectiveness or levels of performance of these controls. The commenter recalls other reports where EPA also agrees that controls are not feasible. In the case of SNCR, for example, the commenter adds that post-combustion control systems, such as SNCR, are not feasible due to the natural-draft operation of the battery – because there cannot be an induced draft, and installation of an SNCR reactor would create backpressure issues impacting the coke oven operation and impacting the control effectiveness. Additionally, the commenter states that potential NO_X emissions from pushing emissions controls at the commenter's facility (EES Coke) are estimated at 12 tpy; therefore, according to the commenter, installation of SCR (or SNCR) for pushing emissions is not expected to be economically reasonable. The commenter expresses their concern regarding the technical feasibility of SCR for pushing operations due to low exhaust temperatures and inconsistent flow rates, as well as potential presence of compounds that may poison the catalyst (*e.g.*, sulfur-bearing compounds or naphthalene). The commenter explains that SCR requires waste gas temperatures of 400 to 800 °F to be effective. Typical temperature of the exhaust gas from a pushing system is approximately 100 °F; therefore, the commenter concludes that SCR would not be feasible without additional energy input (such as additional fuel combustion) to raise the temperature, which would increase energy demand and negate the emissions reduction of SCR. Additionally, because pushing emissions occur when each oven is emptied (or "pushed"), the emissions occur for approximately 5 minutes in duration every 15 to 20 minutes. This cycling means that there is inconsistent exhaust flow to the pushing emissions collection system, or similar system. A NO_X emissions control system, such as SCR, is not designed for systems with inconsistent flow rates and temperatures. Furthermore, the commenter claims that the use of CEMS is an unnecessary burden, as the potential NO_X emissions rate from our pushing emissions collection system stack is approximately 12 tons, and CEMS installation is technically challenging due to the variability in flow and concentration, and particulates within the exhaust posing potential for plugging.

Commenter (0308) recognizes that installation of the require controls for the identified industrial sectors will require a significant period of time where the process units will need to be shut down. The commenter worries, given the condense timeframe, many of these units will have to be offline at the same time and for an extended period of time; possibly impacting grid reliability. The commenter also asserts that the EPA's proposed FIP fails to consider the costs to the source for shutting down a process unit or entire facility for a significant time, nor does it consider the ramifications to the economy of simultaneously shutting down entire industry sectors in 23 states.

Commenter (0416) reiterates that throughout the proposed rule for the iron and steel industry the EPA relies on suggested use of add-on control devices for determining NO_X emissions limits (0.15 lb/ton steel) for affected units but fails to state the basis for identifying such control technologies (low NO_X burners and SCR) as technically feasible and applicable to, for example, an EAF, nor any explanation regarding what reductions could be expected for a controlled EAF. The commenter observes, based on a review of the Proposed non-EGU Sectors TSD, it appears EPA is utilizing the Menu of Control Measures (MCM) and the related Control Measures Database (CMDB) as reference sources for potential control technologies and associated cost-effectiveness information. To understand the EPA's assumptions, the commenter mentions that they reviewed and analyzed cited reference sources and table entries, along with information the CoST. Based on their review of EPA support information, the commenter identified the following four documents deemed (by the commenter) to be the most relevant ones for the steel industry; none of which, however, support EPA's position of technical feasibility for add-on controls for the iron and steel emissions units. The documents, in general, are used to establish costs/cost effectiveness of emissions reductions as well as establish a foundation of EPA's findings, as they relate to add-on controls for the iron and steel emissions units. The reports include the following:

(1) **EPA 1994e:** U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document—NO_X Emissions from Iron and Steel Mills," EPA-453/R-94-065, Research Triangle Park, NC, September 1994.

(2) **EPA 1998e:** Pechan, 1998: E.H. Pechan & Associates, Inc., "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis," prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, Research Triangle Park, September 1998.

(3) **Non-EGU TSD Reference 44:** Midwest Regional Planning Organization (MRPO). 2005. Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis, prepared by MACTEC

(4) **EPA 2010b: EPA, 2010:** "NO_X CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY" (11-11-10), pdf document provided by Donnalee Jones (jones.donnalee@epamail.epa.gov) via email to Amy Vasu 11/16/10.

In a similar comment, commenter (0409) argues that the EPA provides no evidence of technical feasibility in the docket for use of SCR control technologies and specifically identifies the following documents (in addition to the supporting document mentioned above) referenced by the TSD and/or MCM but not included in the docket for this rulemaking.

(1) **MACTEC 2005. Iron** and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis. In the study, MACTEC developed $/ton NO_X estimates for model sources while noting that site-specific factors can significantly impact the installed costs of pollution control equipment.

Response:

As discussed in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is only finalizing requirements for reheat furnaces and boilers in the Iron and Steel industry.

10.6.2.9 Technical Feasibility of SCR/SNCR on Lime Kilns

Comments:

Commenters (0320, 0437) contest that add-on NO_X controls are not feasible at these facilities due to specific design features and operating characteristics of kilns.

Commenter's (0320) remarks focus on two Wyoming facilities (Westvaco and Granger). The commenter agrees with EPA's conclusion that calciners and lime kilns should not be subject to ozone season NO_X emissions limits; adding that the calciners and lime kiln at their Westvaco facility are equipped with PM controls, fire natural gas, and employ good combustion practices to minimize NO_X emissions, and suggest inclusion in the proposed FIP would not result in additional reductions.

The commenter first notes that technologies that involve injecting cooler exhaust gas or water into the calciner or the kiln are not feasible; noting that that the primary NO_X formation mechanism in a gas-fired calciner and a gas-fired lime kiln is thermal NO_X, and because the calcination reaction requires a certain temperature and residence time within the calciner or the kiln, combustion temperature cannot be reduced without changing the size of the calciner or kiln. The commenter recognizes that [lime] kilns and calciners used in other industries have employed SNCR and SCR but insist that those control on not possible at the Westvaco location, because here the natural gas-fired calciners are not equipped with a pre-calciner, pre-heater, or a separate fuel combustion chamber into which a reagent could be injected (or flue gas recirculated) for NO_X control. The commenter further notes that the temperature within the calciner is not in the SNCR effective range because of the trona calcination temperature. The commenter questions the benefits of injecting ammonia or urea into the calciner (as well as into a lime kiln); noting it would be difficult to achieve and may affect product quality. Furthermore, the commenter maintains that while it might be possible to add SCR on the back end of the calciner exhaust system, it would need to be installed after existing PM control equipment to ensure the integrity of the catalyst (sodium is a known catalyst poison). The commenter adds that location at the tail end of the pollution control train would require pre-heating of the gases to create an ideal SCR temperature zone (480°F — 800°F), and maintains that this process would increase operating cost, energy usage, and product of combustion emissions. Similarly, the commenter indicates, based on a RLBC search, that neither SNCR nor SCR have been used on a lime kiln. The commenter stresses that unlike a cement kiln or a coal-fired kiln, the commenter points out that a gas-fired lime kiln does not have a separate combustion chamber or pre- calciner/pre-heater section for heat recovery where NO_X controls might be effectively retrofitted.

Commenter (0437) claims that the two primary factors that affect NO_X emissions in lime kilns burning natural gas are the dry end lime temperature and the combustion of NCGs and/or stripper off gases (SOGs). The commenter notes that thermal NO_X is the primary NO_X formation mechanism in a natural gas-fired kiln and the ammonia present in SOGs will also contribute to NO_X formation. The commenter underscores that there are no technically feasible technologies currently available to control lime kiln NO_X other than good combustion practices. Because the calcination reaction requires a certain temperature and residence time within the kiln, combustion temperature cannot be reduced without changing the size of the kiln. Therefore, technologies that involve injecting cooler exhaust gas (*e.g.*, flue gas recirculation or FGR) or water into the kiln are not feasible. Natural gas-fired kilns and calciners in other industries primarily use LNB to reduce NO_X emissions. It is uncertain whether a burner replacement would achieve lower NO_X emissions from pulp and paper mill lime kilns while still maintaining the required flame profile and temperature for calcination. Although [lime] kilns and calciners used in other industries have employed selective non-catalytic reduction (SNCR) and SCR, pulp and paper mill lime kilns are different because they are not equipped with a pre-calciner, pre-heater, or a separate fuel combustion chamber into which a reagent could be injected (or flue gas recirculated) for NO_X control. The temperature within the kiln is not in the SNCR effective range because of the calcination temperature. Even if it were, injecting ammonia or urea into a rotating lime kiln would be difficult to achieve and would affect product quality and the stability of kiln operation.

Response:

The final rule does not apply to lime kilns in either the Pulp in Paper Industry (Commenter 0437) or the Potash, Soda, and Borate Mineral Mining Industry (Commenter 0320).

10.6.2.10 Technical Feasibility of SCR on Cement Kilns

Comments:

Overall, commenters (0513, 0516) agree with EPA's determination that SCR is not technically feasible to install at cement plants due to unique aspects of the cement manufacturing process and as a result, the proposed controls may not result in any significant reduction in NO_X emissions.

The commenters asks that the EPA consider these industry-specific characteristics and revise its control and monitoring determinations accordingly. At least one commenter (0516) warns of impact of masking and catalyst poisoning (or fouling) on the efficiencies of controls.

Commenter (0513) states their belief that it is neither feasible nor appropriate to require existing preheater/pre-calciner kilns in affected states to install SCR to further improve NO_X removal efficiency. First, the commenter notes SCR has not been adequately demonstrated for cement kilns in the United States – only two cement kilns in the U.S. use SCR, and data related to the installation and use of SCR at these plants is not currently available. As support, the commenter recalls several challenges (*e.g.,* potential problems caused by high-dust levels, the EPA stated in its latest Cost Control Manual Update, associated with operating SCR at cement kilns. Additionally, the commenter disagrees with comparisons between the US and Europe operations because the cement industry differs (significantly due to the increased sulfur content found in the processed raw materials) greatly between the two locations. Second, the commenter stresses the point that cement facilities are fundamentally different than EGUs. The commenter briefly discusses the finding of the report, "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for Use In Portland Cement Industry" by R. Schreiber & C. Russell. More specifically, the commenters recalls that the report notes unique challenges faced by cement plants, including, for example, preheater tower blockage and raw material feed interruption, which could result in severe gas temperature variations at the inlet to the SCR beds. The commenter notes that SCR system suppliers have very limited experience in designing systems to accommodate these types of problems.

Commenter (0516) claims that sulfur from EGUs can be controlled more easily than at a cement plant, because sulfur at power plants are largely controlled by adjusting the type or source of fuel that is used, and because the total sulfur input in the kiln is greatly impacted by the concentration of the sulfur found in the limestone, which, according to the commenter is quarried in close proximity to the cement plant and can be highly variable within the same quarry. Additionally, the commenter notes that sulfur concentrations in limestone vary by region, and suggests that those with limestone containing higher sulfur will have more difficulty installing SCR. The commenter also points out that cement manufacturers must use local limestone to ensure that the cement-making process is economically feasible.

Moreover, the commenter describes the process of masking, which occurs when calcium sulfate (CaSO4) forms on the catalyst's active pores, and when the ammonia – a reducing agent – reacts with the SO_3 or H_2SO_4 present in the exhaust stream to form ammonium sulfate $(NH_4)_2SO_4$ or ammonium bisulfate $(NH_4)HSO_4$, which can condense within the catalyst pores and block them. The commenter adds that the area of the blocked pores then becomes inactive in the NO_X reduction reaction, decreasing efficiency. To mitigate the impact of sulfur on SCR efficiency, the commenter suggests that a plant might need to install a sulfur dioxide (SO_2) removal system (*e.g.,* scrubber) prior to the SCR catalyst bed to significantly reduce the formation of SO3 and ammonium compounds. However, they warn that there could be a significant system pressure drop requiring adjustment to variable speed fans or often full replacement of downstream induced draft fans. The commenter states, to further help mitigate the impact of internal corrosion, due to acid formation from sulfur dioxide and sulfur trioxide, stainless steel may be necessary for construction. According to the commenter, PM concentrations also greatly affect the ability of cement plants to reduce NO_X emissions, because an increased PM concentration causes fouling or plugging of the SCR catalyst bed pores – when PM enters the catalyst structure and deposits on the catalyst's surface and active pore sites, and the blocked pores cannot participate in the NO_X reduction reaction, thus reducing the SCR effectiveness. The commenter claims that PM concentrations in the flue gas at cement plants are significantly greater than at coal-fired boilers, because of the sintering process. Furthermore, the commenter maintains that both PM and sulfur flue gas concentrations impact SCR performance and are variable by the kiln and raw material input. To illustrate their point, the commenter states that raw materials sources from the EU generally contain less sulfur than their United States counterparts, due to underlying geological formations, leading to lower flue gas sulfur concentration for EU kilns; making catalyst fouling and masking a less of a concern. To reduce the amount of masking and fouling of the catalyst bed pores, the commenter implies that SCR can be installed after the baghouse, *i.e.,* downstream of PM controls, which, according to the commenter reduces sulfur and PM concentrations. The commenter stresses a number of hinderances to this approach – *e.g.,* Flue gas exhaust temperatures decrease below the SCR minimum effective operating temperature after the baghouse and would need to be significantly reheated upstream of the SCR to improve NO_X control efficiency, which would result in more combustion emissions from the facility. Although particle loading would be reduced by PM controls upstream of an SCR, the commenter notes that the catalyst bed would still be subject to masking and "poisoning" – when chemical reactions take place between the active catalyst sites and contaminants in the exhaust stream, thus deactivating the catalyst and rendering it ineffective. According to the commenter, two of the most common agents known to cause SCR poisoning are alkaline metals (*e.g.,* sodium and potassium) and CaO, both of which are present in the exhaust flue gas stream of cement kilns due primarily to the content of the raw materials used – as noted in the Alternative Control Techniques Document Update – NO_X Emissions Controls for New Cement Kilns (November 2007). The commenter warns that because the kiln exhaust, post-SCR control (*i.e.,* tail end), would not pass through a baghouse for PM control, any reactions that would take place as a result of the ammonia injection application would go directly out of the stack and could result in increased air emissions from reheating the exhaust gas stream, including NO_X, VOCs, and other combustion- produced pollutants along with elevated opacity from the formation of ammonium sulfates and nitrates resulting in a detached plume. Moreover, masking and fouling of the catalyst beds that could not be avoided would need to be dealt with via cleaning, which is problematic and expensive. The commenter states that this is especially true if dry compressed air is required to protect the catalyst bed during the cleaning process and is dependent on a site-specific demonstration to show how the catalyst will perform over the long term for the specific gas constituent analysis of the specific kiln. According to the commenter it is likely that the increased sulfur in the raw materials, even with the implementation of sulfur removal controls prior to the SCR, will mask the catalyst beds more quickly, resulting in decreased NO_X control efficiency CE and more frequent catalyst changes to allow the catalyst to be sent offsite for regeneration. The commenter explains that a bypass would also be required during the catalyst change period and during periods when the inlet gas is not in the appropriate temperature range. Additionally, the commenter contends that because cement production produces larger, jagged, and irregular-shaped particles as compared to boilers, catalyst beds may erode more quickly and need replacement, reducing the active life of the catalyst bed and increasing operating costs. The commenter states that modern preheater/precalciner kilns are much more thermally efficient (exhaust in 200°F to 400°F range) than older preheater kilns and SCR would require significant supplemental fuel firing to raise the exhaust temperatures to the SCR requirements. The commenter suggests that the EPA must also factor in the SCR efficiency to reduce NO_X emissions at cement plants compared to boilers. The EPA assumes that SCR application on cement kilns will result in 80 percent CE (as noted in EPA's Cost of Control Manual, Section 4). Additionally, SCR effectiveness, when applied after a well-tuned SNCR, which ¾ of the kilns in the 23 affected states utilize, would likely be significantly less efficient. NO_X concentration in the flue gas will be much lower after SNCR thus adding SCR control may not result in any significant reduction in NO_X emissions.

Commenter (0516) cites a few references that they recommend the EPA review, including, for example, the Pueblo Plant Four-Factor Analysis (October 2019).

Response:

As identified in Section V.C.2, the EPA expects that the emissions limits in the final rule for cement kilns can be achieved with combustions controls or the installation of SNCR. As explained in the *Final Non-EGU Sectors TSD*, the limits in the final rule for all cement kilns are based on modest reductions of about 40 percent from current emissions with the installation of SCNR. The TSD also provides information on cement kilns with SNCR installed that are currently achieving emissions lower than or equal to the final emissions limits. The EPA finds that cement kilns should not need to install SCR to meet the emissions limits in the final rule.

10.6.2.11 Technical Feasibility of SCR/SNCR on Kraft Recovery Furnaces

Comments:

Overall, commenters (0343, 0437) assert that SCR/SNCR control technologies are impractical at kraft recovery furnaces due to design and operational characteristics. There is no evidence that currently exists of long-term full-scale SCR or SNCR systems installed and/or are operating (ongoingly) on kraft recovery furnaces anywhere in the world. The commenters cite and, in some cases, provide a brief overview of several studies, reports, etc. as support – *e.g.,* NCASI published Technical Bulletin No. 1051, "An Update to NO_X Control Limits and Technologies for Forest Products Industry Boilers, Kraft Recovery Furnaces, and Lime Kilns," in May 2019.

Commenter (0343) first asserts that there are several untested technical issues surrounding the injection of urea or ammonia within a kraft recovery furnace for NO_X control over a long-term basis. The commenter provides a brief overview of the kraft recovery furnaces operations and design. The commenter alludes that it is not known whether the long-term injection of NO_X reducing chemicals within the furnace could have negative effects on the kraft liquor chemical cycle (for instance, additional nitrogen leaving as sodium cyanite (NaOCN) in the smelt); only determinable by conducting long-term tests. Furthermore, the commenter states that factors such as the impact of large variations in flue gas temperatures at the superheater entrance due to fluctuating liquor firing rates, limited residence times for the NO_X-NH3 reactions available in smaller furnaces, impact on fireside deposit buildup due to reduced chloride purging from long-term NH3/urea use and the resulting impact on tube corrosion and fouling, potential for significant ammonia (NH3) slip and plume opacity problems due to NH4Cl emissions, etc., need to be investigated thoroughly.

Commenter (0437) expresses concern regarding the impacts of high PM concentrations in the economizer region and fine dust particles on catalyst effectiveness – as is catalyst poisoning by soluble alkali metals in the gas stream. If an SCR were to be installed after the ESP, the commenter states the additional energy penalty associated with reheating the flue gas is another aspect that makes application of SCR to a recovery furnace economically infeasible. The commenter states that the only NO_X minimization techniques listed in the RBLC database for recovery furnaces are good combustion practices and optimizing the staged combustion in the design of the existing furnace. The commenter reiterates the point that no other control technologies have been demonstrated in practice for NO_X emissions from recovery furnaces at pulp and paper mills. Additionally, the commenter maintains that the EPA's CoST model does not identify any feasible NO_X control technologies for recovery furnaces at pulp and paper mills. The commenter concludes that the EPA has correctly determined that pulp and paper mill recovery furnaces should not be subject to ozone transport rule requirements.

Response:

The final rule is not applicable to kraft recovery furnaces.

10.6.2.12 Technical Feasibility of Add-On Controls on Non-recovery/Heat-recovery Coke Plants

Comments:

Commenter (0523) suggests that the EPA was correct for not regulating non-recovery/heat-recovery coke plants under the Proposed Rule; adding these plants typically operate at levels that are well-below EU BAT requirements without any add-on NO_X control devices. The commenter recommends that the EPA include language in the proposed rule that specifies their intent to omit controls for non-recovery/heat-recovery coke plants. Otherwise, the commenter warns that the EPA runs the risk of making flawed assumptions regarding the proposed NO_X emissions controls that are in use within the industry, and that are technologically and economically achievable – arguably exceeding EPA's statutory authority. The commenter maintains that if EPA were nevertheless to conclude that the controls are achievable for non-recovery/heat-recovery coke plants and finalize a rule that impacts these plants, the rule would be contrary to the evidence, and thus, arbitrary and capricious (as defined under State Farm, 463 U.S. at 43).

In a similar comment, commenter (0523) disagrees with the assumption that proposed SCR/SNCR controls could be used to achieve the proposed emissions limits (*e.g.,* 0.15 lbs/ton of coal charged from "Coke Ovens (charging)) at a nonrecovery/heat-recovery coke plant. The commenter further argues that the Agency is assuming the feasibility of SCR and/or SNCR to achieve the proposed emissions limits, which, according to the commenter, has never been done at a nonrecovery/heat-recovery coke plant (domestic or globally). The commenter points out that the EPA's supporting documents acknowledge that "coke ovens with [add-on] NO_X

controls in the United States have not been found" and that the EPA cites only one reference for the use of SCR at a coke plant – in a document that is nearly 30 years old. The commenter references Rainer Remus, et al. report, and provides a brief overview of the report's finding of a report as additional support that currently "no SCR installation is in operation at coke oven batteries worldwide." The commenter disagrees, in general, comparing a US based plant with the Japanese byproduct coke plant used to treat the waste gas from coke oven firing; arguing that they are not comparable, for example, in design – non-recovery plants do not have combustion chambers and emit very low NO_X concentrations, and believes the overall report is not applicable to todays' US non-recovery plants.

Response:

The final rule is not applicable to emission units at non-recovery/heat recovery coke plants. As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for coke ovens.

10.6.2.13 Technical Feasibility of SCR on Blast Furnaces (BF)

Comments:

Overall, commenters (0405, 0416) believe that the EPA's proposed use of SCR to control NO_X emissions from blast furnaces is inappropriate; arguing that that use of the control device is not technically feasible. Furthermore, the commenters believe that the EPA's assumed emissions rates and removal efficiencies are arbitrary and not supported with any actual application at a blast furnace or actual data. For these reasons, the commenters maintain that the proposed rule is arbitrary and capricious in requiring add-on controls for blast furnace stoves. The commenters discuss blast furnace operations and the technical infeasibility of installing SCR. Foremost, the commenters mention that blast furnaces are used to convert iron ore and iron-bearing raw materials to hot metal, and the process is completed in a vertical shaft furnace in which raw materials (ore, coke, and flux) are introduced in batch additions via a skip car at the top of the column. The commenters add that combustion occurs within the shaft generating heat that melts the iron and reduces the oxides forming metallic iron. The commenters continue to note that carbon in the coke is first converted to CO_2 which passes upward through the burden heating the ore. In the burden part of the CO_2 produced by coke combustion is reduced to CO by contact with iridescent coke which has been heated by the exhaust gases passing through the bed – also referred to as the Boudouard reaction. The commenters describe that the top gases are passed through a scrubber to remove PM and then used as fuel in the furnace stoves or as fuel for other processes in the steel mill – adding that the higher heating value (HHV) of the blast furnace gas is approximately 95 BTU/scf which results in lower flame temperature and lower NO_X emissions. Additionally, the commenters mention that the furnaces are equipped with regenerative heat exchangers, commonly referred to as stoves, in which the blast air is heated. The commenters note that blast furnace gas and supplemental natural gas are fired in the stoves to heat the stove refractory, called checkers. According to the commenters, some blast furnace stoves are also fired with coke oven gas. When the required checker temperature is achieved, the commenters note that the gas flow is reversed and stored sensible heat is recovered into the blast air. The commenters continue to mention that there are usually

3 to 4 stoves on each furnace, which, the commenters explain are cycled through to provide blast to the blast furnace – combustion gases are vented through a common stack from the stoves.

Commenters (0405, 0416) provide the following additional reasons, with respect to design and installation of SCR on blast furnace stoves, that render SCR controls technically infeasible:

- The exhaust temperature from the blast furnace stoves is too low for the application of SCR (optimal temperature is 600-700 °F) and the extreme volumes of exhaust gases would need to be re-heated with natural gas to achieve the needed SCR activation temperature. Reheating the large volume of gas would require firing wasteful natural gas which would result in additional NO_X emissions and significant GHG emissions.
- There has been no application of SCR to any blast furnace stove in the Iron and Steel sector. Accordingly, SCR vendors have no experience in specification of SCR design or catalyst formulation as they do with the power industry. The EPA has not provided any example of a successful application of SCR at a blast furnace stove.
- The flue gas volume from stove combustion is significant and the surface area for SCR design would be extremely large. Therefore, the physical dimensions of any proposed SCR would also be large. Given the space constraints that would be faced at many facilities, the retrofit cost for installation of the SCR, including structural support, induced draft fan to overcome the additional static pressure loss, physical placement, etc., would be high.
- The achievable removal efficiency of SCR is highly dependent on the inlet NO_X loading. Blast furnaces operate with remarkably high exhaust volumes and relatively low inlet NO_X concentrations, particularly when firing blast furnace gas. The low inlet NO_X concentrations would result in low removal efficiency with no guarantee that the 40-50 percent removal efficiency suggested by the EPA could be achieved in practice. The reduced efficiency would also require a higher ammonia molar ratio likely to result in significant ammonia slip.
- The effect of particulate in the combustion gases from blast furnace gas fuel firing is expected to foul or poison the catalyst, reducing effectiveness even further. SCR vendors have no data on these gas streams and would require significant testing to assess if this issue could be mitigated.
- A limit that is derived based on a blast furnace gas fired stoves, as EPA proposes, cannot be used for stoves when combusting other fuels, such as natural gas or coke oven gas which have different characteristics.

Commenter (0416) believes, based on information used to establish/identify the Proposed NO_X emissions standard or requirement of 0.03 lb/MMBtu and other supporting data, that the EPA intended to apply this limit specifically to blast furnaces stoves and as such, the commenter recommends that the Agency provide language in the proposed FIP clarifying that intent.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for blast furnaces.

10.6.2.14 Technical Feasibility of SCR/SNCR on Basic Oxygen Furnaces (BOFs)

Comments:

Overall, commenters (0405, 0416) believe that the EPA's suggested use of SCR/SNCR on a BOF is inappropriate given that SCR/SNCR is not technically feasible. Further, the commenter claims that the EPA's assumed emissions rates and assumed removal efficiencies are arbitrary and unsupported. For these reasons, the commenters assert that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for BOFs and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed. The commenters recommend that the EPA clarify the specific compliance location, *e.g.*, full combustion control device, electrostatic precipitator, scrubber stack or suppressed combustion flare stack, if the Agency elects to retain limits for BOFs. The commenters recall that the EPA proposes an emissions limit of 0.07 lb/ton for BOFs pursuant to Table 1. Per Table V11.C-3 of the proposed rule preamble – a limit which was established by assuming an emissions rate of 0.14 lb/ton based on unspecified and undocumented "emissions testing" and assuming 50 percent reduction by installation of SCR. According to the commenter (0416), even though the limit is based on an unsubstantiated 50 percent reduction by SCR, the preamble states, a "potential 25-50% reduction by SCR" without providing any technical support of why 50 percent was selected to determine the proposed limit and not some lower number. Specifically, the commenter maintains that the unspecified emissions testing does not allow comments to be submitted to address the likely misapplication of the undocumented testing.

Foremost, the commenters (0405, 0416) discuss BOF operations and the technical infeasibility of installing SCR/SNCR. The commenters state that BOFs are a batch process used in integrated iron and steel facilities to convert hot metal produced in the blast furnace and scrap into steel. The commenters point out that when converting the hot metal (which contains 3.5 and 4.5 percent carbon) to steel, carbon is removed by oxidation in the BOF vessel – a process that is completed by blowing oxygen into the liquid metal bath which oxidizes the carbon, forming CO and carbon dioxide (CO_2). According to the commenters, impurities are removed by forming slag from the addition of flux (quick lime), and the oxidation of carbon generates heat which melts the scrap and raises the liquid temperature to about 2,800°F. The commenters further add that the CO and CO_2 produced are emitted from the vessel along with a high concentration of PM, which is removed using a particulate control device. The commenters state that the blowing process does not generate NO_X, due to the complete reaction of oxygen (O2) with the carbon in the hot metal and the exclusion of air containing nitrogen. The commenters note that the BOF 1-hr blowing process occurs in batch cycles (or heats) with charging, blowing, and tapping events. The commenters add that off-gas temperatures entering the fume capture hood can be between 350°F during charging and 3,200°F during the peak blow period of the heat cycle. The commenters remind that there are two types of BOF furnaces based on how the off gases are processed after leaving the vessel, and the steel industry operates both types.

Furthermore, the commenters note that the full combustion operation captures the vessel off gases in an open hood – ambient air is introduced between the vessel mouth and hood and is controlled by the system draft to prevent fugitive emissions and to assure combustion of CO and hydrogen (H_2) emitted from the vessel. As a result of the combustion, the commenters mention that the gas temperature increases to about 3,800°F and NO_X can be formed as thermal NO_X. The commenters explain that the gases are cooled by convection/radiation in the water-cooled hood to about 450-550°F before being introduced to a cold side ESP for particulate removal or passed through a wet venturi scrubber. The commenters describe the particulate at the exit of the particulate control device (ESP or scrubber) as being very small in diameter, and composed of zinc, lead and other metals, which, according to the commenters would foul or poison the SCR catalyst. The commenters worry that since SCR has not been applied for this source type, SCR designers or catalyst vendors do not have experience in design or specification for BOF NO_X control. The commenters continue to explain that NO_X formation over the batch blow cycle is variable in the primary hood due to the constantly changing off-gas temperature profile and oxygen content of the gases required for hood draft requirements; adding no two heats are identical due to metal chemistry. The commenters observe that the presence of carbon monoxide inhibits NO_X formation and the carbon burn rate during the blow period changes the CO/CO_2 percentage of the gases. The commenters suggest that gas volume at the exit of the ESP on a full combustion BOF is significantly higher than that of suppressed combustion designs, and to maintain catalyst activation temperature, the gases would require heating by combustion of wasteful natural gas between heat cycles, which would generate significant additional NO_X and GHGs. Additionally, the commenters state that during suppressed combustion operation, the vessel gases (composed of CO, CO_2, and H_2) are captured in a close-fitting hood and ambient air is excluded. The commenters further note that once the hood skirt is in position, there is minimal N2 and O2 in the gases resulting in negligible NO_X formation during the blow cycle. Off-gas temperature increases from about 250°F to about 1,800°F at the top of the water-cooled hood during the heat. Sensible heat is removed in the water-cooled hood through convection and radiation. According to the commenters, gases are quenched and particulate is removed by a wet venturi scrubber. Given that NO_X formation is negligible, the commenters assert that there is no application for SCR or SNCR control in the hood between the vessel and the quench. The commenters add that cleaned gases are vented to an open flare for combustion of CO where NO_X is formed. The commenters conclude that the use of SCR/SNCR to control NO_X emissions from the open flare, downstream of a wet scrubber, is not possible given the absence of a physical stack.

Commenters (0405, 0416) identify the following additional reasons why the use of SCR for BOFs is not technically feasible.

- For both full and suppressed combustion units, the EPA has provided no evidence of SCR/SNCR applications nor is the commenter aware that any exist. Accordingly, SCR/SNCR vendors have no experience in specification of SCR/SNCR design or catalyst formulation and no stated removal efficiency can be guaranteed or even theorized without actual test data. Fouling of the SCR catalyst is also a significant concern. The EPA has not provided sufficient data to support the proposed limit or the proposed percent reduction by SCR/SNCR. The EPA provides no technical support of SCR/SNCR for the different types of BOFs and their different emissions points, *e.g.*, open combustion flare and electrostatic precipitator stack.

- For full combustion units:
    - The temperature in the primary hood is variable over the batch process blow period and the required gas temperature and residence time for SCR and SNCR function cannot be achieved.
    - Given the variable conditions, the required molar ratio for ammonia introduction cannot be satisfied.
    - The high concentration of particulates will deteriorate the catalyst and poison the noble metals.
    - If SCR were placed after the ESP or wet scrubber, the gases would require reheating with natural gas to the required reaction temperature. Further, to prevent degradation of the SCR catalyst, the catalyst bed would be required to be held at the operating temperature between the batch processing of heats. This would result in combustion of a significant amount of wasteful natural gas which would generate more NO_X than that which is potentially formed in the combustion hood. Additionally, a significant amount of GHGs would be emitted from combustion of natural gas.
- For suppressed combustion units:
    - NO_X is formed primarily in the open combustion flare. No NO_X mitigation methods can be employed except proper operation of the flare per manufacturer recommendations.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for basic oxygen furnaces.

10.6.2.15 Technical Feasibility of SCR on Annealing Furnaces

Comments:

Overall, commenters (0409, 0416) believe that the EPA's suggested use of SCR on a batch annealing furnace is inappropriate given that SCR is not technically feasible. Further, the commenters assert that the EPA's assumed emissions limits and removal efficiencies are arbitrary and unsupported, and the use of SCR on a continuous annealing furnace is not economically feasible. For these reasons, the commenters state their belief that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for annealing furnaces and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed.

Foremost, the commenters (0409, 0416) discuss annealing furnace operations and the technical feasibility of installing SCR. The commenters argue that applying a limit derived from a recent new furnace application to existing furnaces that have case-by-case retrofit limiting characteristics that increase the costs and decrease the cost per ton of NO_X effectiveness is not appropriate. Rather, the commenters recommend that the EPA conduct a case-by-case RACT analysis that considers all of the retrofit costs involved with each furnace and their different limiting characteristics. The commenters describe the annealing process in which steel is reheated and cooled to alter the characteristics of the metal crystalline structure which reduces stress cracking and produces steel properties required for further processing and forming for the commercial end-products. The commenters mention that there are two basic annealing processes: batch and continuous, and the type of equipment installed in each facility depends on the steel shape, annealing requirements, and the age of the facility. The commenters add that annealing fuels vary depending on availability at the site and economic factors, and can be coke oven gas, blast furnace gas or natural gas. The commenters explain that batch annealing is used for hot strip mill coils, here coils are stacked with an enclosure placed over the stack. The commenters note that a burner is fired upward through the center of the stack heating the coils, and any flue gases are vented through the top of the stack, exiting the building roof monitor. The commenters explain that burner sizes for batch annealing typically range from 5-7 MMBtu/hr and multiple stacks are located in the processing area. The commenters also mention that overhead access is required by crane for removing the enclosure and staking the coils.

Commenters (0409, 0416) highlight the following additional reasons why the application of SCR to batch annealing is technically infeasible:

- Most batch annealing units are fugitive sources which are exhausted through a building roof monitor with no common stack for SCR installation.
- The required overhead access would prevent installation of any post-combustion control system.
- NO_X emissions/concentrations from the very small burners are extremely low and would therefore result in very low SCR removal efficiency.
- Normal flue gas temperatures would be too high for the SCR catalyst.

The commenters describe that continuous annealing is used for annealing flat steel sheet which is then feed to a hot strip mill for processing. According to the commenters, these units typically consist of a preheater zone, soaking zone, and cooling zone – each section employs burners which exhaust to separate exhaust stacks. The commenters admit that SCR is technically feasible for a continuous annealing furnace, it is not cost-effective.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for annealing furnaces.

10.6.2.16 Technical Feasibility of SCR on Ladle Metallurgy Furnaces (LMFs)

Comments:

Overall, commenters (0405, 0416) believe that the EPA's suggested use of SCR on a Ladle Metallurgy Furnaces (LMFs) is inappropriate given it is technically infeasible, and the EPA's assumed emissions limit (of 0.1 lb/ton) and removal efficiencies (40 percent reduction) are arbitrary and unsupported - no baseline emissions assumption, data or reference is provided. For these reasons, the commenters assert that the EPA's proposed rule is arbitrary and capricious in requiring add- on controls for LMFs and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed.

Foremost, the commenters (0405, 0416) discuss LMF operations and the technical infeasibility of installing SCR. Foremost, the commenters note that LMFs are a batch process used in the steel industry to increase the liquid metal temperature for casting and to produce steel grades by adding alloys. The commenters describe that after production in an EAF or BOF, the ladle is covered by a water-cooled hood and three-phase electrodes are inserted through the hood into the liquid. Electric energy is applied to achieve the required metal temperature. The commenters note that alloys are injected through chutes or through wire feeders to adjust the metal chemistry to product specifications. Additionally, the commenters state that emissions from the heating and chemical reactions are vented through the area surrounding the electrodes and captured in a side-draft hood. According to the commenters, the volume of air withdrawn for fume capture is much higher than the volume evolved from the vessel and the gas temperature is therefore low at the fabric filter, *i.e.*, baghouse, inlet (typically 104 to 220 °F). The commenters explain that the LMF batch process has cycles typically lasting between 20 to 40 minutes. The commenters claim that generation of NO_X emissions is very low since there is no combustion source – typical NO_X generation rates are about 0.0036 to 0.0075 lb/ton based on process weight or 0.9 lb/hr to 2.0 lb/hr for a 250-ton ladle weight. The commenter adds that gas volumes for a 250-ton furnace are typically 110,000 actual cubic feet per minute at 128 °F.

Commenters (0405, 0416) state the following additional reasons why the application of SCR for a LMF is technically infeasible:

- The varying exhaust temperatures from the batch LMF process are too low for the application of SCR and the gases would require wasteful reheating to the SCR activation temperature through combustion of natural gas which would likely generate more NO_X then is being removed. Additionally, combustion of natural gas would result in additional emissions of other pollutants including GHGs.
- Very low NO_X concentrations in the gases would result in low removal efficiency.
- There have been no proven SCR applications on an LMF. Accordingly, SCR vendors have no experience in specification of SCR design or catalyst formulation and no stated removal efficiency can be guaranteed or even theorized. The EPA has not provided any example of a successful application of SCR at an LMF.
- Similar to other emissions units in the proposed rule, LMFs must be evaluated on an emissions unit by emissions unit basis for the 100 tpy PTE as is required by EGUs and other sources and not considered collectively as part of the "BOF Shop" grouping that unjustifiably punishes the steel industry.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for LMFs.

10.6.2.17 Technical Feasibility of SCR on Ladle/Tundish Preheater

Comments:

Overall, commenters (0405, 0416) believe that the EPA's suggested use of SCR on a ladle/tundish preheater is inappropriate given SCR is not technically feasible. Further, the commenters claim the EPA's assumed SCR removal efficiencies (40 percent reduction) and emissions limit (of 0.06 lb/MMBtu) are arbitrary and unsupported. According to the commenters, the EPA also fails to distinguish the NO_X rates between newly permitted preheaters and existing preheaters in the proposed rule. For these reasons, the commenters assert that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for ladle/tundish preheaters and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed.

Foremost, the commenters (0405, 0416) discuss ladle/tundish preheaters operations and the technical infeasibility of installing SCR. First the commenters state that ladle preheaters are employed in the steel shop to dry the ladle refractory to prevent steam release during metal addition or to cure refractory after ladle repair. In both applications, the commenter notes that an open gas flame is introduced into the ladle to increase the refractory temperature. According to the commenters, the equipment typically includes an air/fuel burner in a vertical (down-fire) position or horizontal position depending on the manufacturer. The commenters state that the natural gas burners are often very small with heat inputs as low as 0.5 – 1.5 MMBtu/hr. When vertically fired, the commenters mention that a cover is placed over the ladle through which the burner fires into the ladle space. The commenters continue to note that combustion gases are vented through the gap under the cover or through an opening located on the cover (either natural draft or through use of an ID fan) depending on the manufacturer.

Commenters (0405, 0416) states the following additional reasons why the application of SCR to a ladle/tundish preheater is technologically infeasible:

- Most ladle/tundish preheaters are fugitive sources which are exhausted directly into the steel shop. There is no stack and installation of SCR is therefore physically impossible.
- NO_X concentrations from the very small burners are extremely low and would therefore result in very low SCR removal efficiency.
- There have been no proven SCR applications on a Ladle/Tundish Preheater. Accordingly, SCR vendors have no experience in specification of SCR design or catalyst formulation and no stated removal efficiency could be guaranteed or even theorized. The EPA has not provided any example of a successful application of SCR for ladle/tundish preheaters. As discussed above and similar to other emissions units in the proposed rule, ladle/tundish preheaters must be evaluated on an emissions unit by

emissions unit basis for the 100 tpy PTE as is required by EGUs and other sources and not considered collectively as part of the "BOF Shop" grouping that unjustifiably punishes the steel industry

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for ladle/tundish preheaters.

10.6.2.18 Technical Feasibility of SCR on Vacuum Degasser

Comments:

Overall, commenters (0405, 0416) believe that the EPA's suggested use of SCR on a vacuum degasser is inappropriate given SCR is not technical feasible. Further, the commenters claim that the EPA's assumed emissions limit (of 0.03 lb/MMBtu) and removal efficiencies (40 percent reduction) are arbitrary and unsupported. According to the commenters, the EPA has not distinguished the NO_X rates between newly permitted vacuum degassers and existing vacuum degassers. For these reasons, the commenters assert that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for vacuum degasser and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed.

Foremost, the commenters (0405, 0416) suggests that applying a limit derived from a recent new source application, as EPA is proposing, to existing sources that have case-by-case retrofit limiting characteristics that increase the costs and decrease the cost per ton of NO_X effectiveness is not appropriate; rather the appropriate methodology is to conduct a case-by-case RACT analysis that considers all of the retrofit costs involved with each furnace and their different limiting characteristics. With respect to EPA's proposed limits, the commenters discuss its review of permits, specifically permits for the Nucor Darlington and Nucor Tuscaloosa facilities, which demonstrate an emissions limit of 0.005 lb/ton. The commenters question the method by which arrives at a starting point of 0.05 lb/MMBtu, based on their permit review findings. Additionally, the commenters recall that the RBLC indicates for both facilities that a flare is used for CO abatement, which is where the NO_X BACT limits are applied. The commenters point out that, according to the RBLC, EPA uses a NO_X emissions limit assigned to a CO abatement flare as its starting point for its proposed emissions limit. According to the commenters, it can only be assumed that the EPA's intent is to regulate NO_X from a CO abatement flare using SCR. The commenter contends that proposing to regulate extremely small amounts of NO_X from a CO control device as part of an Ozone transport rule is unnecessary and unreasonable; furthermore, technically infeasible.

The commenters state that vacuum degassers are a batch process used in the steel industry to remove undesirable gases from molten steel prior to casting to produce the desired properties of the finished steel products. The commenters continue to note that specific gases to be removed can include hydrogen (H_2), oxygen (O_2), and nitrogen (N_2) dissolved in the liquid metal.

According to the commenters, gases are removed by reducing the pressure above the liquid metal surface to a low value, typically 0.5 – 1.0 mmHg (torr), which is accomplished by placing the metal ladle in a degas tank and withdrawing air from the tank using a vacuum pump (liquid ring pump), mechanical vacuum pump, or steam ejectors. The commenters explain that the process cycles last about 20 minutes depending on heat size. A hard vacuum is held for about 5 minutes during which argon is injected through the ladle bottom. The commenters clarify that stirring the metal with argon allows the dissolved gases to be released at the surface of the metal. According to the commenters, the vacuum is then released, and alloys are added by chute or a wire feeder. During this batch process, the metal temperature decreases, and reheating can be required in an LMF before casting.

The commenters continue to note that gas volumes exhausted from the degas tank vary over the cycle from low to high (*i.e.,* 250 actual cfm to 3,000 actual cfm) depending on product specifications and degasser equipment design. The commenters explain that PM generated by alloy additions are typically removed by a fabric filter or cyclone before entering the vacuum pumps or steam ejectors. The commenters state that steam ejectors are the most common type of degas vacuum pump used but hybrid and mechanical systems are also used, and when the ejectors are used, they operate in series and are used to reduce the pressure in the degas tank with inter- stage condensers between ejectors. The commenters add that a final condenser exhausts non-condensable gases saturated with water vapor at about 180°F; noting the gas volume and gas conditions are specific to each facility operation and can vary significantly. If the degas process is designed to reduce carbon in the metal, the commenters state that CO is generated. The commenters add that during degassing, dissolved oxygen in the liquid metal reacts with carbon and forms CO. If the process is designed to prevent carbon reaction, the commenters mention that additions are made to the metal to consume oxygen and prevent CO formation. If CO is to be controlled in the off gases, according to the commenters, a flare is used to combust the CO to CO_2. The commenters state that air is introduced, in these systems, with natural gas to supplement ignition of the flare – the higher heating value (HHV) of the process gases must be higher than 250-300 BTU/SCF to support the operation of the flare. According to the commenters, NO_X is not expected to be formed in the degas tank due to the gas conditions (low oxygen) and non-contact of tank gases with the metal; however, NO_X can be formed in the flare flame.

Commenters (0405, 0416) state the following additional reasons why the application of SCR to a vacuum degasser is technologically infeasible:

- NO_X is not generated in any significant quantity during the process but is rather formed in the flare flame when CO abatement is required. It is not possible to control NO_X from an open flare using SCR.
- The batch cyclic nature of the process and variable gas flow conditions (*e.g.,* gas volumes and temperatures) are inconsistent with SCR application. Additionally, extremely low NO_X concentrations in the process gas would result in very low removal efficiency.
- There have been no proven demonstrations of SCR on a vacuum degasser. The EPA has not provided any example of a successful application of SCR at a vacuum degasser.

The commenters stress the point that vacuum degassers must be evaluated on an emissions unit by emissions unit basis for the 100 tpy PTE as is required by EGUs and other sources and not considered collectively as part of the "BOF Shop" grouping that unjustifiably punishes the steel industry.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for vacuum degreasers.

10.6.2.19 Technical Feasibility of SCR/SNCR on Coke Oven Coal Charging and Coke Pushing Operations

Comments:

Overall, commenters (0405, 0416) believe that the EPA's suggested use of SCR/SNCR on coal charging and coke pushing operations is inappropriate given SCR/SNCR controls are technically infeasible. Further, the commenters assert that the EPA's assumed emissions limit (of 0.15 lb/ton) and removal efficiencies (a 50 percent reduction by SCR/SNCR for coal charging and 25 percent reduction by SCR for coke pushing) are arbitrary and unsupported. According to the commenters, the EPA cannot establish new enforceable limits based on AP-42 emissions factors that are more representative of average emissions and not maximum emissions. For these reasons, the commenters state that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for coal charging and coke pushing and the proposed emissions limit in Table 1 of 40 CFR 52.43 must be removed.

Foremost, the commenters (0405, 0416) discuss coal charging and coke pushing operations and the technical infeasibility of installing SCR/SNCR on charging and on pushing. The commenters note that coke ovens are a batch process used to produce foundry and metallurgical coke from bituminous coal by indirect heating to remove volatile fractions of the coal. The commenters add that the coal is charged to individual ovens and heated for approximately 15 to 24 hours. The commenters mention that there are two basic coke oven designs: 1) byproduct recovery, and 2) non-byproduct recovery. With the byproduct recovery design, ammonia and other saleable constituents are recovered as byproducts. The commenters imply that coal charging and coke pushing are the two processes at a coke oven battery that the EPA proposes to establish NO_X limits for, and describe each process, noting for example that for by-products coke oven batteries, coal is stored in silos above the coke battery either mid length or at the end of the battery and discharged into bins on the "larry" car – a movable unit which discharges coal at a predetermined tonnage into each battery oven. The commenters explain that charging occurs when the lids (which are later replaced and sealed) on the charging ports of the oven are removed and the coal from the larry car passes through charging tubes to the ports on the top of each oven. The commenters mention that to reduce the potential for fugitive emissions, the head space of the oven is maintained at a negative pressure by aspirating the oven using a steam jet inductor vented to the battery suction main. After coking, the coke is pushed into a hot car and transferred to a quench car and then to a quench tower where direct contact with water reduces the coke temperature. According to the commenters, the pushing of hot coke generates PM emissions which are already regulated and are substantially captured and vented to a PM control system (*e.g.*, a fabric filter or mobile car wet scrubber). The commenters continue to note that gas volumes during the short duration of a push are high, and the temperature of the gas is low. Since the coke pushing and coal charging are batch processes, the commenters state that the volume and temperature of the pushing and charging gases are highly variable over the short duration of less than a few minutes per charge or per push. Further, the commenters contend that NO_X emissions generated from pushing are very low and can be controlled by emissions controls – including Minister Stein type (*i.e.*, moving hoods), fixed hoods, mobile car wet scrubber cars, or sheds. According to the commenters, the volume of captured gases and gas temperatures are specific to each battery. The commenters mention that its members currently operate five coke batteries with two types of push controls (movable hoods and a mobile car wet scrubber car). Furthermore, the commenters point out that NO_X emissions can also be generated by combustion of coal particles during coal charging and controlled by a fabric filter; gas volumes are high and gas temperatures and NO_X emissions are very low.

Commenters (0405, 0416) state the following additional reasons why the application of SCR and/or SNCR for coal charging and coke pushing is technically infeasible:

- SCR/SNCR for coke pushing operations employing a mobile scrubber car is not possible. By design the scrubber cars must enter the quench tower so there is no space on the mobile cars for installation of SCR/SNCR. Additionally, this pushing process is only a couple of minutes and occurs approximately once every fifteen minutes.
- The gases would require reheating, during the charging and pushing and during the interval until the next oven is charged and pushed, to the activation temperature using wasteful natural gas combustion (*i.e.*, duct burners) resulting in additional NO_X formation likely in excess of that which is generated from the pushing and charging operations.
- NO_X emissions rates for pushing and charging are expected to be very low, resulting in low removal efficiency.

Additionally, the commenters assert that because there have been no proven SCR/SNCR applications on coal charging or coke pushing operations, SCR/SNCR vendors have no experience in specification of SCR/SNCR design or catalyst formulation. The commenters add that as of result of vendors' lack of experience, no stated removal efficiency could be guaranteed or even theorized.

Response:

As explained in Section VI.C.3 of the preamble and Section 5.3.3 of this document, the EPA is not finalizing any requirements for coke ovens.

10.6.2.20 Technical Feasibility of SCR on Fossil-Fuel Based Boilers

Comments:

Commenter (0343) claims, in general, that temperature profiles at ESP/FF outlets are not always compatible with SCR operation for fossil fuel-fired boilers that are not base-loaded; often resulting in an energy penalty due to reheating. The commenter adds that plugging and fouling of the catalyst, due to large amounts of fly ash preceding an ESP or FF may also apply; thus, further impacting the effectiveness of SCR operations. The commenter also warns of possible increases in Primary $PM_{2.5}$ emissions, due to formation of sub-micron particulates of NH4SO4. The commenter admits that for base-loaded fossil fuel-fired units, SCR operation is feasible, if there is room to place an SCR unit downstream of the PM control device and cost-effectiveness estimates are reasonable.

Commenter (0362) is concerned, in general, that the NO_X emissions limits in this proposed rule are based on controls that are inherently infeasible in many of the boilers identified in the proposed rule; thus, creating challenges in meeting the proposed emissions limits. To illustrate their point the commenter describes assumptions made by the EPA on the level of control achievable by technologies, such as ultra-low NO_X burners on boilers with a heat input greater than 100 MMBtu/hr – *i.e.,* 75 percent on many boilers with annual NO_X emissions less than 250 tpy. The commenter contends that the application of control strategies, whether be combustion-related controls (ultra-low NO_X burners) or post-combustion controls (SNCR or SCR), are subject to various conditions, such as a furnace geometry that supports the extension of the flame, minimizes impingement and allows for proper combustion box mixing. The commenter explains that residence time in the furnace is necessary to allow reagent mixing and reaction (for SNCR) and temperatures at the inlet of the control device must be sufficient to support the catalytic reaction between the ammonia and flue gas for SCR. According to the commenter, when these technologies are applied to existing boilers and many package boilers, complicated even more by physical geometry limitations created by shipping and construction constraints, the most optimal emissions reductions can be compromised. The commenter also adds that field erected units (built from scrap units or custom designs increase cost and lead time amongst other issues.

Response:

These comments regarding the emissions limits and feasibility of SCR and SNCR on non-EGU boilers are addressed in Section VI.C.5 of the preamble of this final rule. The *Final Non-EGU Sectors TSD* also includes an explanation of the control technologies expected to be installed and the feasibility of those control technologies on the non-EGU boilers subject to the rule.

10.6.2.21 Technical Feasibility of SCR/SNCR on Load-following Biomass, Combination and Fossil Fuel-Fired Boilers

Comments:

Overall, commenter (0343) expresses concern that load-following strictly biomass, combination biomass and 100 percent fossil fuel-fired boilers may not be able to maintain the desired T[emperature] window for proper SCR operation, thus rendering SCR infeasible as a means for NO_X control. Additionally, the commenter notes that inadequate gas temperatures may also lead to significant amounts of unreacted ammonia (slip) being released from cold-side installations, resulting in the formation of condensable PM.

Foremost, the commenter (0343) implies that SNCR only effective in a relatively high, narrow temperature range, and therefore is not suitable for all applications. More specifically, the commenter describes that in a SNCR system, the injection of the reagent must happen within a narrow temperature window (between 1,600 and 2,100°F) for the reduction reactions to successfully complete. The commenter warns that injection at lower than 1,600°F would result in excessive ammonia slip, while, injecting at higher than 2,100°F would cause the ammonia to oxidize to NO_X. According to the commenter, in a load-following boiler, the region of the boiler where the optimal temperature range is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. In such situations, the commenter claims that no locations exist within the boilers with high enough temperature for SNCR to be technically feasible. Additionally, the commenter notes that inadequate reagent dispersion in the injection region due to inherent boiler design, which, according to the commenter can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.,* ammonia slip). The commenter underscores the point that SNCR technology has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads; adding 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

Response:

See Section VI.C.5 of the preamble to the final rule for the changes made to address boilers fired by alternative fuels and about the types of fuels covered by the final rule.

10.6.2.22 Technical Feasibility of SCR/SNCR on Multi-fuel Boiler Operations at an Iron and Steel Facility

Comments:

Overall commenters (0405, 0416) believe that the EPA's suggested use of SCR/SNCR on multi-fuel boiler operations at an iron and steel facility are inappropriate given SCR/SNCR controls are technically infeasible. The commenters claim that the EPA's proposed rule is arbitrary and capricious in requiring add-on controls for blast furnace gas and coke oven gas boilers and the proposed emissions limit in Table 1 of 40 C.F.R. § 52.43 must be removed. Additionally, the commenters request that the rule be clarified to note that the boiler natural gas limit does not apply to blast furnace gas and coke oven gas boilers in the Iron and Steel sector that supplement with natural gas or fire natural gas for periods when the other fuels are unavailable. Finally, the commenters maintain that if EPA elects not to remove the blast furnace gas and coke oven gas limits for multi-fuel boiler in the Iron and Steel sector, the rule should clarify that only the blast furnace gas and coke oven gas limit applies (*i.e.,* 0.20 lb/MMBtu) and that the natural gas boiler limit (*i.e.,* 0.08 lb/MMBtu) does not apply.

The commenters (0405, 0416) discuss multi-fuel boiler operations and the technical infeasibility of installing SCR/SNCR. Foremost, the commenters begin by noting that boilers operated at integrated iron and steel facilities and coke batteries are multi-fuel fired, and due to the age of the facilities and date of boiler installation, the boilers are from different manufactures and design characteristics (fuel, heat release rate, and burner configuration). For these reasons, the commenters explain that the expected NO_X emissions rate will vary considerably from unit to unit burning the same fuel or fuel mixture. The commenters states that these boilers fire a primary fuel such as blast furnace gas or coke oven gas mixed with natural gas added for flame stability and to maintain positive ignition. The commenters define boilers – as swing load with variable steam demand and therefore variable fuel firing input. The commenters add that excess air is variable for each fuel type to complete combustion, and therefore, the flue gas volume will not be constant.

Moreover, the commenters recognize that the F-factor, which relates heat input to exhaust volume, for each of the fuels is significantly different depending on gas composition:

- Blast furnace gas contains a high concentration of inert gases (CO_2 , N2) and a low HHV which requires a higher combustion air volume. Blast furnace gas burns with a low adiabatic flame temperature. The F-factor, dry for blast furnace gas is approximately 16,500 scf/MMBtu but can vary depending on the blast furnace generating the fuel (blast temperature, natural gas, pulverized coal firing, etc.). This in turn changes the CO content of the fuel and the higher heat value. HHV can vary between approximately 65 and 120 Btu/scf, with a typical average around 92 Btu/scf.
- The F-factor, dry for natural gas is 8,710 scf/MMBtu with a HHV of 1020 Btu/scf.
- Coke oven gas is between blast furnace gas and natural gas, with the HHV for coke oven gas typically between 460 and 550 BTU/scf.
- The generation rate of both coke oven gas and blast furnace gas can vary significantly based on the variability of coal charging rates and interruption of charging at the coke ovens and the wind-on/wind-off conditions and the impacted burden input rates at the blast furnace. As a result, the ratios of fuel blends at multi-fueled fired boilers are impacted and are susceptible to variable operating conditions.

The commenters note that because the heat release rates of the differing gas blends are significantly different and susceptible to variable coke oven and blast furnace operations, the required location for SCR (or the correct injection points for SNCR) to operate at the correct temperature would vary as gas composition varies. The commenters disagree with EPA's assertion that the use of SCR and/or SCNR on a multi-fuel boiler at an iron and steel facility is therefore not technically feasible because of the variable conditions on a multi fuel boiler; claiming the Agency fail to provide any example of a successful application of SCR in an Iron and Steel sector. The commenters contend that industry boilers are already regulated by boiler NO_X regulations (state NO_X SIP and NO_X RACT regulations) in states like Indiana, Ohio, Michigan, and Pennsylvania. The commenters mention that the RACT determination/study for Pennsylvania indicates determined that the exhaust temperature was below the necessary SCR reaction temperature and that the cost effectiveness of SCR was well above EPA's proposed cost-effective threshold of $7,500 per ton of NO_X reduced; as well as identify other technical challenges with installing SCR on existing multi-fueled boilers. Finally, the commenters assert that the EPA's proposed emissions limits for boilers, which fails to consider the multi-fuel blends that are fired at numerous boilers throughout the Iron and Steel sector, contradicts previously supported limits using a 99 percent upper predictive limit of actual test data to ensure that enforceable limits are realistically achievable under a multitude of operating conditions.

Response:

See Section VI.C.5 of the preamble to the final rule for the changes made to address non-EGU boilers fired by alternative fuels and about the types of fuels covered by the final rule.

10.6.2.23 Technical Feasibility of SCR in Startup, Shutdown and Malfunctions (SSM) Events & Daily Backstop Limit (State Emission Budgets)

Comments:

Overall commenters (0400, 0409, 0519, 0533, 0554, 0557) believe that the proposed backstop limit is technically infeasible and the projected costs of installing SCR are incorrect. The commenters suggest that the EPA not compel installation of SCR via a backstop daily emissions rate; maintaining that the daily rate does not account for startup and shutdown events, nor is it achievable on all days – EPA acknowledges, in the proposed FIP, that the proposed limit can be met only 95 percent of days during the ozone season.

Commenter (0400) notes that SCR controls typically do not begin operating at design values until almost 24 hours from startup; resulting in well-performing units exceeding the daily NO_X 0.14 lbs/mmBtu emissions limit – a limit exceeded even if the proposed limit was based on a multi-day average. The commenter does not agree with EPA's assigned 10-year life for recovery of SCR capital costs, which lowers the calculated incurred cost per ton of NO_X removed; rather many units will be terminated/retired. According to the commenter, if EPA were to use a 5-year life for recovery of SCR capital costs to account for near-term retirements, costs associated with retrofitting coal-fired units with SCR would be materially higher than that projected by the EPA.

Commenter (0409) asserts that the proposed daily NO_X emissions rate cap of 0.14 lbs/mmBtu for units with SCRs is not achievable in many cases, specifically during startup events. If a daily rate is retained, according to the commenter, the final rule should eliminate reasonable startup times from the daily emissions limit calculations or set a daily NO_X mass limit to account for startup times.

Commenter (0519) argues that the EPA's assumed emissions rates for SCR fail to account for technical limitations (*e.g.*, startups, temperatures, loads, etc.). Specifically, the commenter claims that the identified emissions rate of 0.05 lb/mmBtu (for new SCRs) is untested, as it has only been demonstrated at a limited number of coal units throughout the United States, and points to previous rulemakings and EPA's acknowledgements as additional support. The commenter maintains that the EPA's limited assessment of feasibility is not sufficient to provide reasonable support for EPA's assertion that this rate is achievable for all coal units with new SCR retrofits. Additionally, the commenter expresses concern that the proposed emissions rates fail to account for impacts to SCR operations. The commenter states BPA falsely assumes that SCR can still operate at same emissions rate year after year, with no degradation – an assumption that is inconsistent with actual operations, particularly where EPA's daily backstop emissions rate effectively requires continuous operation of these devices to attain and maintain the required flue gas temperatures to initiate and sustain the NO_X reduction reactions occurring in the SCR. The commenter also claims that the proposed rates fail to account for SCR startups, which can similarly impact achievable flue gas temperature and consequently NO_X emissions rates. Similarly, the commenter adds that the EPA's proposed rates fail to adequately account for temperature in assessing emissions rates (according to Sargent & Lundy's analysis), "temperature of the flue gas in the SCR plays a major role in performance – *e.g.,* dictates the location of where an SCR system is placed within the duct path to maintain efficiency of the reactions. Moreover, the commenter briefly mentions technical limitations that may alter the facility's ability to meet NO_X emissions rate at lower load.

Commenter (0553) opposes the method used to develop the proposed daily backstop emissions limit of 0.14 lb/mmBtu. The commenter points out that the limit was established using data from only units with SCR that achieved an average seasonal emissions rate of 0.08 lb/mmBtu or better; excluding many units that are effectively operating their SCRs but have average emissions higher than 0.08 lb/mmBtu. The commenter believes that the 0.08 lb/mmBtu performance rate was set based on an average level of performance for the entire population, so the range of performance should also be established using the same set of units. According to the commenter, if the daily average is set based only on the best performing units, then many EGUs that are properly operating and maintaining their SCRs but are greater than the 0.08 lb/mmBtu ozone season average performance level would be more likely subject to the 3 to 1 surrender for emissions exceeding the daily emissions rate; resulting in an inequitable cost of compliance – at the current market value of $30,500 per allowance (an increase from $25,000 per ton as reported in June 2022), even a relatively small excess amounting to 16 tons of emissions spread across the ozone season would have an additional allowance cost of $1 million. In addition, the commenter claims that by penalizing EGUs for performance that may well be within the normal short-term capability of the installed control systems, the provision (daily backstop emissions limit) reduces the pool of NO_X allowances beyond what EPA deemed necessary when it established the state NO_X budgets. After reviewing the actual daily emissions rate for the 2021 ozone season (for eight coal-fired boiler EGUs subject to the Revised CSAPR Update Rule), the commenter determined that these units would have exceeded the proposed daily emissions limit of 0.14 lb/mmBtu on multiple occasions (by 68 tons) despite units' levels of performance; requiring 136 additional allowances for compliance at a cost of more than $4 million.

In a similar comment, commenter (0553) stressed the point that there is considerable range of daily performance among EGUs that are continuously operating SCR throughout the ozone season, and that variation does not suggest that EGUs are "idling" the SCR. Instead, the commenter explains, that such variations relate largely to periods of low load operation where SCR operation may be affected in a similar manner as startup and shutdown. The commenter recommends that if EPA includes a short-term emissions rate in a final rulemaking, it is important that the EPA changes the proposed daily emissions rate to account for operation of EGUs in conditions where the SCR cannot be operated or must operate with limited performance – *i.e.,* exclude any calendar day that a unit at any time was in startup or shutdown. That would include a more complete engineering and statistical analysis of the entire population of units equipped with "existing" SCRs, including use of an upper 99 percent value for the expected range of control. First, the commenter defines startups and shutdown periods and states that boiler operating conditions (during startups and shutdown periods) prohibit SCR operation, because low flue gas temperatures do not allow for ammonia reagent injection – a requirement established by the vendor. The commenter warns that failure to follow these practices (stop SCR operations) will cause harm to the catalyst and degrade NO_X performance once the unit is online, and potentially impacting the entire unit's operation through formation of ammonia byproducts that can lead to severe fouling of the SCR and downstream boiler components. [An analysis was performed by the commenter for 2022, similar to the one conducted in 2021, and comparable results were achieved – *i.e.,* the commenter expects to exceed daily rate particularly during startup and shutdown events, and to see increases in the cost of allowances. The commenter continues to express concerns that once online these units' require tuning, which further impacts performance.] The commenter argues that the EPA's evaluation of SCR operation does not adequately recognize the constraint to system loads. The commenter briefly describes efforts taken to gain additional SCR performance (load reductions); however, the commenter stresses that unit operation at lower loads continues to create conditions where SCR operation is either limited or at times must be curtailed. Second, according to the commenter, it is more common for EGUs to be called upon for low load operation for long periods, and as a result they must now increase load in response to demand for short periods before again dropping to minimum load. The commenter further explains that because the ability to inject ammonia at low temperature is limited an average emissions rate of 0.14 lb/mmBtu may not be achievable on days where the unit must operate for an extended period at minimum load. The commenter contends that as with startup and shutdown, this operation is consistent with good engineering practice and the design limitations of the SCR; thus, penalizing is not appropriate (at a 3 for 1 allowance surrender). The commenter states that there is a certain level of variation of NO_X performance associated with good engineering practice for environmental controls, and this variation in performance is well-documented – citing excerpts from EPA's "Discussion of Short-term Emission Limits Final Rule" (Docket No. EPA-HQ-OAR2018-0295-0171). According to the commenter, at the time, the EPA's review of the data did not suggest that EGUs were spending considerable time at low utilization; However, based on the commenter's perspective and experience, over the last few years, the commenter has noticed a trend – coal-fired units are being called on more and more to operate at very low load conditions for extended time (except on days of high demand). The commenter explains that an inability to operate SCR effectively at low load conditions increases the risk of a unit exceeding EPA's proposed daily emissions rate limit. The commenter maintains that such operation is necessary and should not be subject to penalty (or be considered 'idling controls') in the form of additional allowance surrender.

In a similar comment, commenter (0553) asserts that the level of performance and the mass emissions from any given unit will be impacted by a number of factors including, equipment wear and tear – *e.g.,* the multi-year catalyst replacement cycle and unit load cycles; therefore, basing the emissions rate on a single year is not appropriate. The commenter argues that setting the proposed NO_X budgets based on these 2021 performance levels takes away compliance margin that had been built for operation, but it also reduces the overall states' budget (Indiana);

penalized for essentially complying with the Revised CSAPR Update Rule. The commenter notes that in 2021 their ability to achieve improved performance and build margin from coal units equipped with SCR allowed it to provide allowances to its natural gas fired units that operated beyond their allocations; adding that the proposed FIP would impede that normal market function of the NO_X Budget Program.

In a similar comment, commenter (0553) warns that the EPA's method of setting the emissions rates can significantly impact state budgets. To illustrate, the commenter alludes to a potential loss of over 500 tons of NO_X to the Indiana budget for 2023, as a result of a reduction in the budgeted emissions rate for affected units that took steps to achieve improved performance in 2021 (under the 2021 Revised CSAPR Update). The commenter maintains that this approach affects sources in Indiana through reduced allocations and limits the margin of allowances which may be available to the market and impacting the ability of a trading program to function properly. The commenter contends that the NO_X budgets established in the 2021 Revised CSAPR Update have already significantly impacted the market, driving allowances prices (greater than $30,000 per ton), which according to the commenter is well beyond what EPA had found to be cost-effective control for EGUs. The commenter expresses concerns that continued steps to push EGUs to the limit of achievable performance will only exacerbate this concern.

Commenter (0544) disagrees with EPA's assertion that units with optimized SCR performance achieve a seasonal NO_X emissions rate of 0.08 lb/mmBtu or less. According to the commenter, the "optimized" NO_X emissions rate is only achievable when the SCR catalyst is brand new; doesn't consider aging equipment (catalyst); making it less likely that even an otherwise "optimized" SCR could achieve the proposed emissions rate of 0.08 lb/mmBtu. The commenter highlights the fact that the EPA recognizes that owners will have to replace worn SCR catalysts more frequently; adding to the number of startup and shutdown events for the year, along with contributing to increases in NO_X emissions because SCRs cannot operate during those time.

In a similar comment, commenter (0544) expresses their concerns with how the daily backstop limit is designed – specifically the proposed rule fails to account for SSM periods, and the commenter worries that the provision will unduly penalize unplanned and unavoidable exceedances that are often outside the operator's control, in an effort by the EPA to disincentivize operators from choosing to idle SCR controls (87 Fed. Reg. 20,111). The commenter contends that the amount of allowances needed to address a single day's exceedance compared to the amount of allowances necessary to address "planned poor performance" is an insufficient justification for imposing a penalty on events outside of an operator's control. According to the commenter, an operator that maintains its SCR in an optimized state and runs it continuously, when it is technically feasible to do so, will be significantly penalized (unreasonably) on days of SSM (under the proposed rule). The commenter briefly mentions EPA's authority under the CAA in regard to the proposed daily limit and highlights the point that the EPA recently-reinstated its SSM Policy specifically to address the need for alternative requirements during SSM events. The commenter maintains that such requirements should be "narrowly tailored and take into account considerations such as the technological limitations of the specific source category and the control technology that is feasible during startup and shutdown." 80 Fed. Reg. 33,980 (emphasis added). The commenter (0544) recognizes and provides an overview of operating procedures that may limit an SCR's performance. First, the commenter stresses the point that SCRs cannot operate during SSM events – the daily backstop limit cannot incentivize the operator to operate and optimize the SCR during those times as EPA has indicated in the Proposed Rule and instead serving as a penalty for operators who cannot use the SCR during an SSM event and exceed the daily backstop limit. Furthermore, the commenter suggests that the EPA's assessment of the market incentives is also misplaced, and their assumption that owners would select the purchase of allowances over optimizing SCR equipment doesn't consider current (historically high) market prices and conditions.

In a similar comment, commenter (0544) states their belief that daily backstop limit cannot function as an incentive for units with federally enforceable permit conditions requiring continuous SCR operation because they are already required to do so—it will only punish units for the inherent technological limitations of the SCR. The commenter mentions that RTOs ultimately determines when the units will run based on the dynamics of the electricity grid at that time, completely divorced from any decision by the unit's operator. The commenter identifies 4 options EPA can take to ensure that units are continuously operating and optimizing SCR controls, and provides a briefly overview of each measure:

(1) At a minimum, the daily backstop limit should not apply to units with a federally enforceable permit condition that requires continuous operation of an SCR;
(2) In determining whether the Daily Backstop Limit has been exceeded, emissions during the defined SSM period (in which the SCR cannot technically be operated) should be removed from the analysis;
(3) On days with an SSM event, an alternate daily backstop limit should apply;
(4) Exceedances of the daily backstop limit that are due to an SSM event would be subject to a fixed penalty per ton of NO_X emissions, rather than a 3-for-1 allowance surrender penalty – in an effort to provide an economic incentive to EGUs to minimize SSM events to the extent it is within their control.

Commenter (0557) maintains that the EGU daily rate ignores the practical function of SCRs, it cannot be university applied, and therefore, the commenter advocates for the elimination of the daily rate or, at minimum, excluding startup conditions from daily rates when the SCR is not able to operate. The commenter provides a brief overview of the SCR process, which first requires that a unit reach around 580° F for subbituminous coals and 620° F for some bituminous coals before the SCR can function – a key temperature that varies based on many factors, such as fuel composition and associated sulfur content. The commenter continues to note that once the SCR reactor reaches the minimum temperature then ammonia reagent can be injected. At this time, the commenter notes that post-combustion NO_X removal begins, but only at a partial level until the unit comes up to full load. SCR's full NO_X removal potential can be realized once the unit reaches its design values. The commenter recalls that past data shows a 0.14 lbs/mmBTU daily rate can be met (on 95percent of days) during the ozone season. The commenter objects to the use of a daily rate; adding achievement is highly unlikely, due to, for example, unavoidable startup operation – time periods for startup vary across units.

Commenter (0758) insists that the EPA improve the methodology for setting emissions budgets for electric generating units (EGUs), strengthen requirements for large coal-fired steam EGUs, and expand its EGU control strategy to more types of units and to higher cost thresholds to achieve emissions reductions that are needed for downwind attainment. The commenter believes that the EPA's budget-setting methodology is overly conservative and must be adjusted to enable tighter budgets that reflect the level of performance that controls can achieve. Additionally, the commenter asks that the EPA eliminate or narrow the threshold of 150 tons of NO_X per ozone season as a prerequisite for installation of SCR on oil- or gas-fired steam EGUs and include SCR retrofits on uncontrolled natural gas combined-cycle units in the budgets.

In a similar commenter, commenter (0758) states, as another potential near-term reduction measure, installation of SNCR on coal-fired EGUs smaller than 100 MW and on all circulating fluidized bed coal-fired EGUs must inform budgets beginning in 2024. The commenter urges the EPA "decouple" the timing of SCR and SNCR retrofits, to secure 1,000 tons of NO_X reductions from SNCR retrofits of smaller coal- fired EGUs in the near term, because, according to the commenter, it would better reflect what is likely to happen in the real world and not doing so would artificially inflate emissions budgets. The commenter agrees, in general, with EPA's conclusion that although the emissions-reduction potential of SCR is greater than that of SNCR, smaller coal-fired units rarely elect to deploy SCR; adding that it is unlikely that allowance prices in later years of the program would provide sufficient incentive to install SCR on these smaller coal-fired units—which will only become less economic to run as other generation resources with lower fuel costs come online. The commenter concludes that it is therefore preferable and statutorily required to secure the near-term emissions reductions from SNCR installations on smaller coal-fired units and begin to reflect those reductions in the budgets in 2024. Furthermore, the commenter states that because EPA likewise does not assume, as noted in the proposed FIP, that circulating fluidized bed coal-fired EGUs will install SCR, the EPA must factor into the state emissions budgets the emissions reductions from installations of SNCR on these units in 2024 as well.

Response:

See the EPA's discussion of the basis for the backstop emission rates in preamble Sections I, VI.B.1.c-d, and VI.B.7, as well as Section D of the Ozone Transport Policy Analysis Final Rule TSD. Section VI.B.7 also contains the EPA's response to other comments on the backstop daily rate provisions. As discussed in those sections, the EPA is not finalizing a requirement that units meet a daily emission rate, rather the EPA finalized an enhancement to the seasonal trading program where emissions, under some circumstances (i.e., daily emission rates were greater than or equal to 0.14 lb/mmBtu and the total ozone season emissions for the unit on those days higher than the emission rate of 0.14 lb/mmBtu are greater than 50 tons) are subject to a 3-for-1 surrender ratio.

In response to commenter 0400, as described in the NOX Mitigation Strategies Final Rule TSD, the default book life assumed by the EPA for capital recovery for SCR is 15 years, not 5 or 10 as asserted by the commenter. As described in preamble Section V.B, in finalizing the enhancements to the trading program, the EPA extended the imposition of the backstop emission rate to no later than 2030 for units that do not already have SCR installed.

In response to comments about startup and shutdown in relation to the daily backstop rate, see Preamble Sections VI.B.1.c-d and Section D.3 of the Ozone Transport Policy Analysis Final Rule TSD. The EPA's methodology for identifying the backstop emission rate included all daily emission values from units with seasonal emission rates less than or equal to 0.08 lb/mmBtu (see Section D.1 of the Ozone Transport Policy Analysis Final Rule TSD for details). This includes startup and shutdown events and times with various load levels. For the discussion about the appropriateness of the 0.05 lb/mmBtu emission rate for newly installed SCR, see the NOx Mitigation Strategies Final Rule TSD and Response to Comment Section (10.6.1.1).

For the EPA's discussion about the appropriateness of maintaining optimized SCR operation over the course of a season, see Sections III.B, V.D, and VI.B of the preamble and the NOx Mitigation Strategies Final Rule TSD. As described in the preamble Section V.B and further explained in the NOx Mitigation Strategies Final Rule TSD, the EPA identified 0.08 lb/mmBtu as a reasonable level of performance for units with optimized SCR. However, as shown in the worksheet "Coal Steam Above" in the "Daily Backstop rate for existing SCRs - accommodating startup shutdown.xlsx" Excel workbook included in the docket, there are 81 units with seasonal emission rates >0.08 lb/mmBtu that had less than 50 tons of 2021 Ozone Season NOx Daily Excess. In fact, three units had emission rates >0.08 lb/mmBtu and had zero tons of 2021 Ozone Season NOx Daily Excess. Additionally, as shown in the worksheet "Coal Steam Above" even among units with seasonal emission rates >0.08 lb/mmBtu, only 43 units had over 50 tons of 2021 Ozone Season NOx Daily Excess. In response to comments that state that SCRs may not be able to maintain optimized operation at low loads, operation at lower loads is under operator control to some degree (e.g., ramping down at night to low load levels), and we have observed operation where units ramp down at night, but maintain operation of the SCR (see, e.g., preamble V.B.1.a and VI.B.1.c.i and spreadsheet entitled “Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data”).

As described in the EGU NOx Mitigation Strategies Final Rule TSD, SCR catalyst does have a minimum operating temperature, but certain design features can be incorporated that allow the SCR to successfully operate over a broader EGU load range, including at lower operating load times and at earlier times during start-up. These features were successfully installed with past SCR retrofits where owners have chosen to adopt these. The results of these improvements can be observed in improved SCR operation and improved SCR operation during lower load times.

As described in preamble Section I and Section D.3 of the Ozone Transport Policy Analysis Final Rule TSD, the 3-for-1 allowance surrender ratio applies only after the first 50-tons exceeding the daily backstop rate have been excluded.

In response to commenter 0553, where a single year is preferred for budget setting, see preamble Section VI.B.4 for the response. For budgets based on dynamic budget setting, we are using data from multiple years (see preamble Section VI.B).

In response to the assertion by commenter (0544) that the daily backstop rate should not apply to units with a federally enforceable permit condition that requires continuous operation of an SCR, see Response to Comment Section 5.2.1.5.

In response to commenter 0758, see preamble Sections I and V.B.1 for a discussion of EGU NO_X mitigation strategies.

10.6.2.24 SCR – Non-EGU Screening Assessment

Comments:

Commenter (0359) asserts that the proposed emissions limits are arbitrary and capricious. The commenter recalls, based on the screening assessment, that the cost per ozone season ton of NO_X reductions averages $9,500 per ton and as high as $16,910 per ton for each emissions unit. Considering that facilities in this industry have over 25 emissions units per facility, the commenter worries that the cost of these non-technically demonstrated proposed emissions limits are exorbitant for one emissions unit, let alone for the entire facility to attempt to comply. The commenter identifies the following additional areas of concern:

- There is only one blast furnace identified in the screening assessment with a control cost of over $10,000 per ozone season ton. The justification for the proposed NO_X emissions standard of 0.03 lb/MMBtu for blast furnaces assumes a 40-50 percent reduction from a burner replacement plus SCR is based on one NO_X RACT rule limit.
- The screening assessment does not include any electric arc furnaces (EAF). The justification for the proposed NO_X emissions standard of 0.15 lb/ton of steel for electric arc furnaces is based on example permit limits at around 0.2 lb/ton and assumes 25 percent reduction from the installation of SCR to achieve 0.15 lb/ton of steel. This limit is more than twice as stringent as the 2022 BACT emissions limit (0.35 lb/ton of steel) for a newly permitted facility in West Virginia.
- The screening assessment does not include any ladle/tundish preheaters. The justification for the proposed NO_X emissions standard of 0.06 lb/MMBtu for ladle/tundish preheaters, which is almost twice as stringent as the 2021 BACT permit limit identified, assumes a 40 percent reduction with the installation of SCR.
- The screening assessment does not include any reheat furnaces. The justification for the proposed NO_X emissions standard of 0.05 lb/mmBtu for reheat furnaces, which is almost twice as stringent as the Ohio RACT limit, assumes a 40 percent reduction with the installation of SCR.
- The screening assessment does not include any annealing furnaces. The justification for the proposed NO_X emissions standard of 0.06 lb/mmBtu, which is 33 percent less than the lowest emissions limit that the EPA identified, is based on an assumption of 40 percent reduction from the single lowest limit due to the installation of SCR.

Response:

Comments regarding the Screening Assessment and the use of a cost-per-ton threshold as part of that analysis are addressed in Section 2.2 (Non-EGU Industry Screening Methodology).

As discussed in Section VI.C.3 of the preamble, the EPA is only finalizing requirements for reheat furnaces and boilers in the Iron and Steel industry. For reheat furnaces, the commenter is incorrect that no reheat furnaces were identified in the Screening Assessment. In fact, two reheat furnaces at Arcelormittal Cleveland LLC were identified in the Screening Assessment. As explained in more detail in the preamble and the *Final Non-EGU Sectors TSD*, the EPA is finalizing requirements for reheat furnaces to install low NO_X burners if they do not already have them installed.

10.7 High Natural Gas Prices

Comments:

Commenter (0326) states their belief that the EPA's assumptions do not adequately reflect the current energy prices. The commenter briefly describes how natural gas prices affects NOx mitigation strategies through both the cost of ammonia and urea (since natural gas is a raw material for each reagent) and through the ability of sources to shift generation between coal and natural gas operation (*i.e.*, generation shifting is more likely to occur when the increased fuel cost is offset by the cost of installing and operating additional NOx controls). The commenter recalls that the RIA at proposal shows Henry Hub natural gas prices at $2.39/MMBtu, even though the price of natural gas appears to have doubled since January 2022, and as of May 2022. The commenter adds that the Henry Hub natural gas spot price reached the highest observed in the last ten years ($8.14/MMBtu). The commenter warns that the sharp increase in natural gas prices may hinder the ability of sources to shift generation among assets. The commenter recalls that the TSD states that "$900/ton of NOx removed is a broadly available cost point for units that currently are partially operating SCRs to fully operate their NOx controls while $1,600/ton of NOx removed is a broadly available cost point for units to restart and fully operate existing idled SCR." Additionally, the commenter notes that the EPA estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in 2025, a 7.8 percent reduction in coal-fired electricity generation, a 0.15 percent increase in natural gas-fired electricity generation, and a 3.8 percent increase in renewable electricity generation in 2025 as a result of this proposed rule. The commenter further notes that the EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2025. The commenter believes that these assumptions are not reflective of current market prices and urges the EPA to revisit their original assumptions regarding both cost-effectiveness and the rule's potential effects on the supply, distribution, and use of energy.

Response:

The EPA updated the natural gas price used for the IPM modeling of the final rule (see "Updated Summer 2021 Reference Case Incremental Documentation for the 2015 Ozone NAAQS Actions"). The EPA addresses the impact of recent fuel price volatility in connection to generation shifting in Section V.B.1.f of the preamble. The EPA conducted sensitivity analysis of NO_X mitigation costs at a range of urea prices in Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD.

The EPA also notes that the Henry Hub natural gas price has decreased dramatically since the summer of 2022 and, as of February 28, 2023, was $2.65/MMBtu. Furthermore, the March 2023

EIA Short Term Energy Outlook forecasted the average 2023 Henry Hub natural gas price to be $3.02/MMBtu.

10.8 High Cost of Ammonia/Urea Reagent In SCRs

Comments:

Commenters (0290, 0326, 0363, 0364, 0404, 0536, 0554, 0760) assert that the EPA's projections of cost-effectiveness for the proposed controls is woefully out of date and as a result, the Agency underestimated the cost of ammonia and urea used by SCR systems as a reagent. More specifically, the commenters state that the 2016 cost data used by the EPA does not account for current inflation and ignores recent relevant global developments. At least one commenter (0760) warns that the EPA relies to a significant extent on the assumption that numerous sources will be adding SCR systems to their facilities to control NOx; however, the commenter suggests that the high costs of ammonia or urea may discourage the addition of these systems.

Commenters (0326, 0760) ask that the EPA account for current natural gas prices and consider their impact on ammonia and urea prices; adding (from at least one commenter) that the average price of anhydrous ammonia per ton is $1,607.80 and the average price of urea per ton is $944.67 [Illinois Production Cost Summary, Il. Dept. of Ag Market News, Production Costs Report, dated 6/16/2022]. Commenter (0554) states that the current cost of a 50 percent weight solution of urea—required for SCR operation at Gavin, and many other EGUs—is $990.67 per ton of urea, according to the U.S. Department of Agriculture, Illinois Production Cost Report (2022); whereas the cost estimates for optimizing existing SCRs assumed a cost of only $350 per ton of urea. Commenter (0326) recognize that ammonia prices generally follow natural gas prices because ammonia is produced primarily from natural gas, and U.S. ammonia prices closely follow international ammonia prices because approximately 14 percent of total U.S. ammonia consumption is met by imports. The commenter further notes that generally, prices of commodity chemicals (ammonia) closely correlate with prices of feedstock (natural gas), because the global ammonia market is highly interconnected. The commenter states that compared with natural gas prices in the U. S., which have remained relatively steady, international natural gas prices have risen rapidly over the past 12 months, pulling ammonia prices higher. Note that the commenter includes a number of tables to demonstrate changes in the cost/prices of ammonia and urea in the U.S. and worldwide.

Commenters (0326, 0363, 0364, 0404, 0536, 0554) claim that the EPA's cost estimates/assumption for urea – $350/ton for a 50 percent weight solution of urea, is inconsistent with current data from the U.S. Energy Information Administration. The commenters states that, according to the Energy Information Administration, the U.S. price of ammonia, the primary source of nitrogen fertilizer, has risen by a factor of six in just the past two years with current prices at $1,600/ton. Commenters (0404, 0536) declare that the cost-benefit analysis performed by the EPA was based upon market assumptions that no longer exist and should be reevaluated prior to implementation.

Commenter (0540) refers to the EPA's statements: "In the cost estimates presented here, EPA uses the cost for urea, which is greater than ammonia costs, to arrive at conservative estimate. ... EPA assumed the cost of $350/ton for a 50 percent weight solution of urea." The commenter states that This statement is inconsistent with current data from the Energy Information Administration (EIA). In its report dated May 10, 2022, the Energy Information Administration stated that the price of ammonia “has risen by a factor of six in the past two years” with current prices at $1,600/ton. The cost-benefit analysis performed by the EPA was based upon market assumptions that no longer exist and should be reevaluated prior to implementation.

Commenter (0290) says it is especially important to note an increase in the cost of ammonia/urea over the years, since the cost of reagent such as ammonia or urea is one of the largest contributors to the variable O&M cost for SCR's and the largest cost for SNCR systems. The commenter states their opinion that using the default value in the Retrofit Cost Analyzer is inaccurate and underestimates the cost-effectiveness for SCR and SNCR controls.

Commenter (0547) states, in addition to Retrofit Cost Analyzer being too general to accurately assess costs and unit cost concerns such as physical location, design, and set up are not accounted for in the EPA’s analysis, that the EPA should also update its cost estimates based on more recent dollar values. Foremost, the commenter notes that IPM cost algorithms (use to create the “Retrofit Cost Analyzer” spreadsheet) limits user input to a few basic parameters such as unit size, coal type, and heating value. Therefore, the commenter asserts that the analysis addresses only the basic level of inputs that impact the actual cost and does not account for the more site-specific factors, such as site-specific constraints and constructability issues, that can [impact] costs. The commenter briefly discusses an example where the Retrofit Cost Analyzer falls short is the retrofit difficulty factor that the EPA utilizes for retrofit of SCRs, as support.

Commenter (0760) notes that the war in Ukraine, which has significantly driven up the price of natural gas – the feedstock for making ammonia, coupled with sanctions imposed by the U.S. and other nations on Russia (as a response to the Ukraine war) has resulted in the cost of ammonia and urea nearly doubling; adding Russia is one of the world’s largest ammonia/urea fertilizer exporters. The commenter (0760) warns that the requirement for significant quantities of ammonia and urea for SCR systems could further contribute to the harm being experienced by many nations who cannot afford the increased fertilizer prices and may lead to increases in food prices and food scarcity concerns, as fertilize becomes less accessible.

Commenter (0361) recalls that the global market for natural gas has encountered significant volatility, partly resulting from increasing reliance on natural gas generation and partly from the supply issues caused by the Ukraine war. The commenter recognizes that supply chain issues have a global impact; shipment/availability of ammonia and other materials to operate SNCRs are encountering serious delays and impacted by higher costs; impacting ability to comply with and meet the proposed deadline.

Commenter (0760) states that it is unclear from the record whether EPA considered space constraints on the ability to install SCR systems and asks that the EPA exempt facilities who are space constrained and cannot feasibly install SCR systems. The commenter notes that SCR systems require a fair amount of land and space for ductwork to connect to existing units, in addition to space needed for ammonia or urea storage.

Response:

The EPA conducted sensitivity analysis of NO_X mitigation costs at a range of urea prices in Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD. The EPA also conducted sensitivity analysis that accounted for inflation, specifically by looking at the impact of higher capital costs on the dollar-per-ton mitigation costs of SCR retrofits. For the impacts of inflation, The EPA considered the inflation reported by the Handy-Whitman Steam Production Index that exceeded the general inflation rate (i.e., CPI-U); only the difference in the inflation rates was considered because that would be all that remained once current prices were converted back to 2016 dollars

The EPA also notes that the Henry Hub natural gas price has decreased dramatically since the summer of 2022 and, as of February 28, 2023, was \$2.65/MMBtu. Furthermore, the February 2023 EIA Short Term Energy Outlook forecasted the average 2023 Henry Hub natural gas price to be \$3.40/MMBtu. As natural gas is a feedstock for urea and the prices are highly correlated, it is expected that urea prices will see similar declines. Indeed, urea prices, as reported in the February 23, 2023 Illinois Production Cost Report had dropped to \$655/ton from the July 2022 price of \$895/ton (and a 2022 high of \$1027/ton).

The costs the EPA calculated for different NO_X mitigation strategies are representative of the cost of the mitigation strategy, typically the average cost of a population of EGUs or an EGU that is representative of the average unit. Some units will have higher costs and some will have lower costs. The representative costs are not to be considered a limit above which a mitigation strategy may not apply to an EGU.

In regard to the comment that the Retrofit Cost Analyzer is too general to take into account site and unit specific concerns, the EPA notes that the Retrofit Cost Analyzer was developed to provide a Level V engineering cost estimate for the average unit with the characteristics input; the actual costs for a unit may be higher or lower depending on a variety of factors, including details of specific sites. The Retrofit Cost Analyzer includes a retrofit difficulty multiplier that can be adjusted for specific retrofit projects, but a multiplier of 1 is meant to represent an average retrofit project for the current un-retrofitted fleet. To develop representative costs for SCR/SNCR optimization and retrofitting, the EPA considered costs developed in two different ways. First, the EPA estimated mitigation costs for a typical unit. Second, the EPA calculated the weighted average mitigation cost for a large set of units (typically 50 to 200 units). The standard error of the mean decreases by the inverse of the square root of the number of units (*e*.g., for a sample size of 100 units, the standard error would decrease by a factor of 10). Using these two methods gives the EPA confidence in the representative mitigation costs.

In regard to the comment that the EPA should use more recent year dollars in the rule, the EPA notes that it consistently used 2016 dollars across the entire rule and those values are readily converted to other year dollars.

10.9 Supply Chain Issues

Comments:

Shipping Delays (Raw Materials)

Commenter (0533) highlights that supplies of ammonia may become limited as the war in Ukraine persists and sanctions on Russian goods continue to be imposed and warns that this lack in raw materials will affect not only new installations at EGUs and non-EGUs but also supply needs at units already retrofitted with SCR and SNCRs.

Commenter (0547) notes that the COVID-19 pandemic has led to vast disruption in industry activity – including creating delays in the time for procuring and shipping/receiving of materials, and as a result, the materials needed to install new SCRs have been difficult to find and purchase. The commenter briefly discusses how supply inventories were high pre-pandemic, but businesses quickly liquidated inventories to help ease the financial impacts they faced as a result of the pandemic. The commenter explains that although demand has again increased (post-pandemic), businesses have been unable to bring back supplies to pre-pandemic levels. The commenter highlights that the sectors with the highest reported domestic supply delays were in manufacturing, construction, retail trade, and wholesale trade [U.S. Census Bureau]. The commenter (including 0546) warns that competition within the market amongst other SCR projects and infrastructure projects will likely create further bottlenecks and further hindering the ability to obtain the raw materials (such as steel) necessary to install SCRs/complete retrofits.

Increases in Prices

Commenter (0518) maintains that the EPA's non-EGU screening assessment (at Step 3) is based on dated, faulty information (more than five years old) and should be reevaluated using current economics (in evaluating costs of controls) and a realistic timeline for installation. The commenter highlights that the EPA presented the estimated costs of controls in 2016 dollars, effectively giving the appearance of lower costs; however, the commenter notes that when applying the most recent Consumer Price Index (CPI) for April 2022, the $7,500 in 2016 dollars is actually $9,063 per ton in today's dollars. The commenter strongly urges the Agency to conduct an updated analysis using current CPI values, and in a manner that allows the public the ability to comment.

Commenter (0547) notes that sudden shifts in supplies chains (pre-, during, and post-pandemic) has heavily impacted prices, and stresses that these changes coupled with changes to the market (inflation) caused by current geopolitical situation continue to impact market prices.

In a similar comment, commenter (0557) warns that Virginia's businesses and industry will be at risk of electricity interruptions, while the environmental compliance costs of proposed FIP will come at a large cost, detrimental to the affordability of energy.

Step 3 (Multifactor Test)

Commenter (0547) contends that the high cost and time required to complete installation, SCR retrofits do not pass the multi-factor test in Step 3, and the associated emissions reductions should not be considered to be significantly contributing to downwind nonattainment or maintenance receptors.

Compliance Timeline

Commenters (0301, 0501, 0526, 0533, 0547) indicate that, in general, due to domestic and global market conditions, companies' ability to plan, purchase materials, including off-the-shelf hardware (such as steel, piping, nozzles, pumps, and related equipment) and successfully install SCR control technology by 2026 is largely impractical. Commenter (0501) asserts that the EPA substantially underestimated affected units (needing to be retrofitted); thus, underestimating the length of time needed to retrofit existing units and the level and number of expert services needed. The commenter suggests that the EPA consider (when evaluating labor/the number of qualified services providers needed), for example, service provider and equipment availability, budget cycles and lead time for procuring equipment, and timing for permitting. Commenter (0301) disagrees, based on current market conditions, with EPA's determination that 36 months is an appropriate time frame to accommodate scheduling, installation, and commencement of operation (of SCR and SNCR controls), and warn that states/sources (including small MWC) will undoubtedly struggle to achieve this schedule and may incur excessive costs to meet this deadline. The commenters add that competition for resources during this 36-month window will directly affect one's ability to comply and increase prices for these goods and services. Commenter (0533) briefly describe struggles they have faced so far in trying to implement SCR systems, including failure to receive confirmation from contractors regarding an expected installation date/timeline and delays in standard maintenance due to supply chain issues – unable to obtain the necessary part(s). The commenter contends that supply chain issues are not expected to be resolve in the next two years (to meet 2024 ozone season budget requirements). The commenter concludes that without consideration of these factors by the EPA in the proposed FIP, timing and cost assumptions for the installation of NO_X controls are unrealistic and arbitrary. According to commenter (0547) an implementation expectancy of 2026, may force companies to risk failing to meet attainment requirements due to an inability to implement SCRs or take on a substantial price burden. The commenter adds neither of which EPA has factored into its timing analysis.

White House Documentation

Commenters (0547, 0798) emphasize that supply chain issues have been well-documented by the Executive Branch (White House) and U.S. government (Department of Commerce). Commenter (0798) cites a 2017 Presidential Memorandum (in addition to Presidential Policy Directive 21) and asks that the EPA consider (as it evaluates how to effectuate the requirements of the good neighbor provision) key findings that suggests domestic steel production is "essential" for national security applications. The commenter cautions that even if it was possible to meet the proposed rule's command-and-control limitations on NO_x, installing the required control technologies may cause temporary closures (and in some cases permanent closures) of iron and steel facilities all around the nation all at once; crippling U.S. surge capacity.

Compliance Deadline Extension

Commenter (0508) specifically requests that the EPA extend the compliance deadline for pipeline emissions sources until at least May 1, 2027, and states their support the option of allowing companies to request a longer compliance deadline based on good cause. The commenter notes that pipeline emissions sources are spread out in rural settings providing additional challenges of planning and scheduling replacement, retrofits, or the addition of controls, and in addition, companies require additional planning and coordination of down times with upstream suppliers and downstream purchasers/users.

Response:

the EPA observes that many supply chain issues have been resolved in the past year or are expected to be resolved within the current year, as described in the NOx Emission Control Technology Installation Timing for Non-EGU Sources report and the EGU NO_X Mitigation Strategies Final Rule TSD. While some material prices are still elevated above pre-pandemic levels, they are currently in a period of rapid decline from their recent highs.

Commenters did not provide evidence to support their assertions that supply chain issues observed in 2021 and 2022 would persist well into the future and therefore would necessarily cause a delay in emissions control retrofits. However, the compliance schedule of the final rule does take the potential for such delays to persist into account through the availability of case-specific demonstrations of need for non-EGUs and phase-in of SCR-level stringency for EGUs through the 2027 ozone season. See Section VI.A of the preamble. Furthermore, some components mentioned, like monitors, are not required until later in the construction process, meaning they do not prevent SCR construction from starting while they are being acquired. The EPA also notes that some components may be salvaged and reused from units with SCRs that have recently retired or soon will retire. Finally, based on the projection of a relatively smaller set of EGUs that will retrofit SCR, there is not a large risk of orders being delayed due to many EGUs retrofitting SCR over a few years.

11 Other Miscellaneous Comments

11.1 Request for Extension of Comment Period

Comments:

Commenters (0197, 0198, 0200, 0201, 0208, 0209, 0210, 0211, 0213, 0222, 0224, 0231, 0232, 0233, 0239, 0241, 0237, 0235, 0244, 0245, 0258, 0266, 0278, 0295, 0300, 0303, 0396, 0407, 0428, 0436, 0499, 0518, 0520, 0539, 0554, 0557, 0798) request an extension of the public comment period. They indicate that due to the size and technical complexity of the proposed actions and the related data and modeling, more time is needed for commenters to provide meaningful information and feedback.

Commenters (0197, 0200, 0201, 0208, 0211, 0224, 0231, 0232, 0239, 0235, 0245, 0258, 0300, 0396, 0436, 0499, 0520, 0542) specifically request an extension of 60 days.

Commenter (0210) specifically requests an extension of 60-90 days.

Commenters (0213, 0233, 0237, 0278, 0407, 0303) specifically request an extension of 90 days.

Commenter (0557) specifically requests an extension of 45 days.

Commenters (0198, 0200, 0222, 0232, 0233) request an extension of the comment period due to the overlap between the comment periods of the proposed action and other proposed rules that, if finalized, would result in the disapproval of good neighbor SIPs for 19 states. They state that this extension is necessary because otherwise commenters will not have enough time and resources to adequately evaluate every proposed action.

Commenters (0208, 0210, 0224, 0231, 0233, 0235, 0244, 0245, 0258, 0407, 0539, 0798) state that since some materials were not made available until after the Notice of Proposed Rulemaking was published in the Federal Register, and other data related to the proposed action are only available upon request, the public needs more time to obtain and review that information. Commenters (0237, 0303) further request that the extended comment period not begin until "all detailed emissions and modeling files and other supporting data" are released by the EPA.

Commenter (0798) observes that the EPA previously denied an extension of the comment period on the grounds that it has an obligation to move "as expeditiously as possible." Commenter states that "EPA delayed evaluation of underlying state SIP submissions and modeling for more than a year. It is unreasonable for EPA to delay any evaluation of good neighbor provision requirements and then use that very delay as a reason to prevent the public from having adequate time to evaluate and comment on EPA's proposed approach."

Response:

The EPA granted one 15-day extension of the comment period from June 6 to June 21, 2022, in response to various requests for EPA to allow additional time for public input on its proposed action. 87 FR 29108 (May 12, 2022). The EPA responds to comments claiming the comment period was inadequate for the public to provide meaningful input in Section 10.1 (Complaints About Not Having Long Enough Comment Period).

11.2 Health and Environmental Effects

11.2.1 Ozone and Public Health

Comments:

Commenters (0212, 0216, 0223, 0247, 0257, 0259, 0261, 0263, 0265, 0273, 0285, 0296, 0307, 0316, 0339, 0367, 0379, 0402, 0423, 0492, 0502, 0522, 0641, 0644, 0715, 0725, 0741, 0758, 0763, 0780, 0758, 0864, 0881) collectively described benefits that, in their views, would be anticipated in finalizing this rule and/or expressed the view that the EPA had, potentially, underestimated benefits associated with implementing this action. In citing multiple studies and reports, commenters identified an array of health effects which they ascribed to ozone and which they claimed EPA had not fully considered in its benefits assessment.

Response:

To accompany the proposal, the EPA prepared the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard). In the RIA at proposal, the EPA quantified benefits for all/some of the endpoints the commenters identify and qualitatively assessed other endpoints that the EPA associated with ozone. Specifically, Chapter 5 of the RIA at proposal discussed how the Agency estimated the benefits to human health of reducing concentrations of ozone from affected EGUs (electrical generating units) and non-EGUs (or other stationary source emissions sources) and $PM_{2.5}$ from affected EGUs. Section 5.3 provided a qualitative discussion of health impacts associated with direct exposure to NO_2 and SO_2 (independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone) due to the absence of air quality modeling data for these pollutants in this analysis. Qualitative rather than quantitative characterization of benefits related to certain health effects should not be interpreted to mean that the EPA concludes there are no such benefits-associated with reductions in exposures to ozone, $PM_{2.5}$, NO_2 or SO_2. Rather, limitations in available health effects information, data, time, and resource limitations prevented EPA from quantifying those-effects.

11.2.2 Indian Tribal Ozone Health Concerns

Comments:

Commenters (0259, 0257, 0402) write that Indian Tribes and their members are disproportionately susceptible to the health effects of ground-level ozone. Exposure to ground-level ozone can adversely affect Tribal community members including children, Tribal elders, members with asthma, and others who gather and use plants of cultural significance. Studies show that Native Americans and Alaska Natives have a disproportionate incidence of asthma and are at risk from exposure to ozone. Specifically, American Indian and Alaska Native children are 60 percent more likely to have asthma as non-Hispanic white children. Impacted species also include those on which Indian Tribes depend for subsistence, medicine, or other traditional practices. Many of these practices take place during the summer months, also the period during which ground-level ozone is most prominent.

Response:

To accompany the proposal, the EPA prepared the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard. Chapter 5 of the RIA at proposal discussed how the Agency estimated the benefits to human health of reducing concentrations of ozone from affected EGUs and non-EGUs, and $PM_{2.5}$ from affected EGUs. For information on the applicability of the final rule to Indian country, see preamble Section III.C.2, *Application of Rule in Indian Country and Necessary or Appropriate Finding*.

11.2.3 Ozone Environmental Effects

Comments:

Commenters (0214, 0247, 0257, 0339, 0367, 0379, 0402, 0492, 0509, 0641, 0643, 0758) collectively described benefits that, in their views, would be anticipated in finalizing this rule and/or expressed the view that the EPA had, potentially, underestimated benefits associated with implementing this action. In citing multiple studies and reports, commenters identified an array of environmental effects which they ascribed to ozone and which they claimed EPA had not fully considered in its benefits assessment.

Response:

To accompany the proposal, the EPA prepared the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (RIA at proposal). In the RIA at proposal, the EPA quantified benefits for some of the endpoints the commenters identify and qualitatively assessed other endpoints that the EPA associated with ozone. Specifically, Chapter 5 of the RIA at proposal discussed how the Agency estimated the public environmental benefits associated with NOx emissions reductions from affected EGUs (electric generating units) and non-EGUs (non-electric generating units) and $PM_{2.5}$ emissions reductions from affected EGUs. Section 5.4 provided a qualitative discussion of environmental impacts associated with exposure to ozone, NO_2 and SO_2 (independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone) due to the absence of air quality modeling data for these pollutants in this analysis. Qualitative rather than quantitative characterization of benefits related to certain effects should not be interpreted to mean that the EPA concludes there are no such benefits associated with reductions in exposures to ozone, $PM_{2.5}$, NO_2 or SO_2. Rather, limitations in available information, data, time, and resource limitations prevented EPA from quantifying those effects.

11.2.4 Ozone EJ Concerns

Comments:

Commenters (0216, 0223, 0247, 0492, 0502, 0714, 0715, 0780, 0763, 0882) write that the impacts of ozone pollution disproportionately fall on minority (black and brown), low income, and rural communities. Commenter (0492) notes that asthma also disproportionately burdens children, families with lower incomes, and people of color. Commenter (0714) provides the following examples of increased exposure to air pollution in low-income communities:

> "On August 7, 2021, smoke from multiple western wildfires converged on the Denver metro area, mixed with the ground level Ozone, and raised the Air Quality Index to 162, the highest recorded on the entire planet that day. Wildfire smoke is not a pollutant subject to this rule, but it is a visible illustration that pollutants travel great distances, and when it comes to pollutants that can be regulated, Americans need the federal government to utilize its authority to reduce harm.
>
> In Denver, we are working to protect our most vulnerable populations from air pollution by transitioning to renewable heating and cooling. Many of our low-income residents live in older homes without air conditioning. On hot days when the air quality is at its worst, these residents are forced to keep their windows open for circulation, but that exposes them to toxins present in the polluted air. By replacing aging gas furnaces with air-source heat pumps – which provide both heating and cooling – these residents will finally be able to protect themselves from outside air pollution.
>
> The need for such interventions would be reduced if the EPA's proposed Cross State Air Pollution rule were adopted."

Commenter (0763) adds that the mortality rates of lung and bronchus cancer in Houston show that minority populations, epically black and Hispanic communities, are disproportionately impacted by the release of PM from chemical manufacturing and industry when compared to white counterparts.

Commenters advocate for the rule to be adopted for environmental justice reasons.

Response:

To accompany the proposal, the EPA prepared the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard. Chapter 6 of the RIA at proposal discussed how the Agency assessed environmental justice concerns associated with concentrations of ozone from affected EGUs (electrical generating units) and non-EGUs (or other stationary source emissions sources).

11.2.5 Secondary Environmental Impacts of SCR

Comments:

Commenter (0294) writes that there will be secondary environmental impacts associated with the installation of controls which were not considered in the proposed rule. Commenter writes, "Although the Good Neighbor Proposed Rule does not mandate the use of SCR, the NO_X emissions limits are based on flue gas treatment using SCR. The energy and secondary environmental impacts of SCR include the following:

- Catalyst disposal. The majority of the catalysts used in SCR systems contain titanium and vanadium oxides, which need to be disposed of properly when the catalyst is replaced. Other commonly used materials are tungsten trioxide, platinum, and zeolites.

- Ammonia storage. Liquid ammonia and concentrated ammonia vapor, which are extremely hazardous materials, must be transported and stored safely. Depending on the number of SCR units that would need to be installed, the Good Neighbor Proposed Rule could force companies into USEPA's Risk Management Plan program (42 U.S.C. § 7412® and 40 CFR 68) and OSHA's Process Safety Management requirements (29 CFR 1910.119(a)(1)) to prevent accidental releases of ammonia.

- Energy impacts. SCR has the potential to impact energy requirements by affecting the thermal efficiency of combustion processes. SCR results in a pressure drop across the catalyst that requires additional electrical energy for the flue gas fan.

These indirect energy, waste, and regulatory impacts would result in additional costs of control that are not included in the above figures."

Response:

The indirect impacts associated with SCR operation such as catalyst disposal, ammonia storage, and energy impacts associated with additional flue gas fan operation are in fact accounted for in the estimates of SCR costs prepared by the EPA for this rule for both EGU and non-EGUs. Estimates of SCR O&M costs and other impacts for EGUs as presented in the EPA's Retrofit Cost Analyzer as documented at https://www.epa.gov/system/files/documents/2023-01/13527-002%20Coal-Fired%20SCR%20Cost%20Methodology.pdf include all of these cost items in the variable O&M cost estimates. Estimates of SCR O&M costs and other impacts for EGUs and non-EGUs included in the EPA Air Pollution Control Cost Manual, another source of cost estimates prepared by the EPA, also include all of these items in its annual cost methodology found in the SCR cost chapter, which was updated in 2019 and found at https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

11.3 Ozone Transport (General Comments)

Comments:

Commenters (0248, 0367, 0324, 0503, 0510, 0521) write that interstate transport of ozone and associated pollutants is a large problem for many states when it comes to attaining the NAAQS, and they support the proposed rule because it will address this issue. Commenter (0367) adds that these pollutants can sometimes travel hundreds of miles. Commenter (0521) declares their commitment to improving air quality and remaining in attainment – adding that maintaining attainment is essential to growth and prosperity in the community.

Response:

Thank you for the comments. The EPA agrees that ozone-precursor emissions can travel substantially long distances and that this rule will address the interstate transport of ozone from the covered states.

11.3.1 State-Specific Ozone Transport Concerns

Comments:

Commenters (0248, 0367, 0324, 0503, 0510) provide more specific information about the effects of upwind emissions on certain downwind states. Commenters (0503) state that half of Maryland’s jurisdictions and the majority of its population still reside in nonattainment areas for the 2015 ozone NAAQS, and research shows that transported ozone from upwind states is sometimes already above 70 ppb as it enters Maryland.

Commenter (0248) describes the effects of upwind transport on metropolitan Washington, which is currently designated as being in nonattainment. According to the Maryland Department of the Environment, roughly 70-90 percent of Maryland and the District of Columbia’s ozone problem on exceedance days originates in upwind states.

Commenter (0367) discusses several states and metropolitan areas in the Northeast and Mid-Atlantic, including:

- The New York-Northern New Jersey-Long Island (NY-NJ-CT) metropolitan area, which was designated as being in moderate nonattainment.
- The Philadelphia-Wilmington-Atlantic City (PA-NJMD-DE) metropolitan area, which was designated as being in marginal nonattainment.
- The Greater Connecticut area, which was classified as being in marginal nonattainment.

Response:

Thank you for your comments.

Comment:

Commenter (0367) observes that despite concerted efforts by these states to reduce emissions - including devoting significant resources to meeting standards, implementing emissions control measures, and participating in the Ozone Transport Commission and multiple iterations of the federal NO_X Budget trading programs - as well as certified ozone data demonstrating successes in cutting in-state emissions in Delaware, New Jersey, and Connecticut, these areas still did not attain the NAAQS by 2021 and may be reclassified to moderate nonattainment status.

Response:

Thank you for your comments.

Comment:

Commenter (0510) also discussed the NYMA, noting that base case modeling demonstrates that eight states outside the NYMA significantly contribute to monitors with ongoing nonattainment issues for the 2015 ozone NAAQS in Connecticut in 2023.

Response:

EPA identifies states that are significantly contributing to downwind receptors in the New York metropolitan area. This rule provides a full remedy to resolve interstate ozone contributions from these states.

Comment:

Commenter (0324) states that Wisconsin's elevated shoreline ozone levels are a result of upwind emissions compounded by the meteorological effects of Lake Michigan. Commenter adds that the EPA's modeling indicates that Wisconsin is only responsible for 8-16 percent of the ozone measured at its nonattaining monitors, while other states contribute 42 to 48 percent. Additionally, the most recent modeling conducted by LADCO estimates Wisconsin sources are responsible for an even smaller portion of the ozone at these monitors, only 2-5 percent.

Response:

See Section IV of the preamble and Section 3 of this document.

11.3.2 Research and Studies on Ozone Transport

Comments:

Commenter (0531) states that the EPA has failed to take into account any recent relevant scientific studies of ozone in nonattainment areas despite the availability of such studies and EPA's participation in that research. Commenter explains that there are several studies which provided significant amounts of data that are relevant to the proposed rule and which were conducted with EPA's knowledge, input, and physical and financial assistance. Commenter writes that the EPA is obligated to identify these studies and take their results into account, as they directly relate to EPA's modeling, control strategy choices, and analysis of the effectiveness of said control strategies. Commenter argues that it is arbitrary and capricious for EPA to use a voluntary agreement with an arbitrarily expedited schedule as a basis for avoiding the development of a control strategy based on the research EPA funded and to which it contributed.

Commenter (0531) argues that to capture the inland penetration of the lake breeze, the model (WRF-CHEM) needs accurate Lake Michigan water temps and correct model physics options. The EPA's use of the Pleim- Xiu Land Service Model (LSM) (EPA, 2022) does not adequately capture the lake breeze inland penetration (Abdioskouei & et al, 2019). Use of NOAH LSM does a better job at capturing the lake breeze inland penetration. The EPA in its CSAPR WRF modeling used the 'ipxwrf' program to "initialize deep soil moisture at the start of the run using a 10-day spinup period (Gilliam and Pleim, 2010). Land use and land cover data were based on the U.S. Geological Survey (USGS) for the 36NOAM simulation and the 2011 National Land Cover Database (NLCD 2011) for the 12US simulation." (EPA, 2022). The LMOS 2017 study suggests that for the WRF modeling in the LADCO region that "WRF simulations in the LADCO region should use the SMAP soil moisture analyses to constrain soil moisture and MODIS Green Vegetation Fraction (GVF) retrievals to constrain the Leaf Area Index to improve the overall performance of the LADCO meteorological modeling framework in simulating land/lake-breeze circulations planetary boundary layer depths, and surface fluxes" (Abdioskouei & et al, 2019).

Commenter further writes that instead of taking the time and effort to analyze recent study data collected by the EPA and others (NASA, NOAA, NESCAUM, LADCO, EPRI and multiple universities) during the 2017 Lake Michigan Ozone Study (2017 LMOS) and the 2018 Long Island Sound Tropospheric Ozone Study (2018 LISTOS) to come up with the best ozone control strategy or strategies in consultation with states, the EPA has ignored the data and state consultation processes and hurriedly proposed the same control strategy that it has already put into place in three previous rulemakings and which EPA knows has not been effective at reducing ozone in the few remaining ozone non-attainment areas.

Commenter believes it is arbitrary and capricious for EPA to ignore the most recent peer reviewed science when developing and imposing a control strategy with significant costs on states and regulated utilities. To avoid analyzing the results of these studies or other more recent EPA research on ozone problems, the EPA relies on a 15-year-old 2007 research study (Bergin et. al) and a 2013 modeling study (Liao et al) of 2007 ozone episodes as support for this proposed FIP. The EPA also cites the original 2011 CSAPR rule which relies on the RIA for the 2008 ozone Standard as the most recent assessment of the impact of NO_X transport on ozone formation at 76 FR 48222. This footnote reference to the 2011 CSAPR rule and the earlier 1998 NO_X Budget SIP call are the extent of EPA's analysis of "assessments of ozone control strategies" at 87 FR 20039.

Commenter states that the EPA's reliance on the 2007 study is misplaced and ignores the voluminous data that indicates that reductions of NO_X from EGUs in distant states does not and has not reduced ozone design values in either the Chicago non-attainment area nor the NYMA non-attainment area. Commenter suggests that if a 60 percent reduction in NO_X emissions from EGUs has not reduced ozone design values in these nonattainment areas in the last ten years, the EPA should reconsider its control strategy.

Commenter notes that the LMOS 2017 study is relevant to the proposed rule since the modeling links emissions from states like Missouri to nonattainment and maintenance monitors in the area studied by LMOS 2017. USEPA's 2016v2 model platform and results links Missouri emissions sources to the following four monitors: Wisconsin 550590019 Chiwaukee

Prairie Kenosha, Wisconsin 550590025 Water Tower Kenosha, Wisconsin 551010020 Payne and Dolan Racine, and Illinois 170317002 Water Plant Cook. These four monitors are all within the LMOS study area and the data collected and resultant published studies have significant bearing on fate and transport of ozone and other pollutants at these monitor locations. Since the conclusion of the LMOS 2017 data collection efforts in June 2017, researchers and scientists have been analyzing and reporting on the data collected and the implications to air quality control efforts in and around the Chicago ozone nonattainment area including areas of Northern Illinois and Southern Wisconsin along the Lake Michigan shoreline. Several peer reviewed research studies analyzing the LMOS data have been published since that data collection effort.

Commenter observes that despite clearly being aware of the LMOS 2017 study – as the EPA participated in the effort and various EPA scientists are credited in published studies resulting from the study, the EPA does not analyze or mention the LMOS 2017 study or the resulting data anywhere in the proposed rule, docket, or TSD. Commenter states that had EPA reviewed the science included in the docket, it would have realized that the modeled link between Missouri emissions sources and Chicago nonattainment area monitors is not reliable.

Commenter explains that the Long Island Sound Tropospheric Ozone Study (LISTOS) was a multi-agency collaborative field campaign conducted during the summer of 2018 to improve the understanding of ozone chemistry and transport from New York City to areas downwind, especially the Long Island Sound and Connecticut coastline which constitutes the NYMA nonattainment area. Special attention was paid to test and evaluate coupled WRF-CMAQ simulations to different horizontal model resolutions, particularly to model representations of sea breeze circulation, low level jets, and boundary layer evolution. In addition, ozone vertical profiles were measured and analyzed with respect to multiple instrument measurements of other parameters such as wind speed and direction, with specific attention to the lower troposphere (0- 2 km from the surface). LISTOS data were also used to characterize the influence of long-range transport of smoke from wildfires into the area. Study results suggest the importance of using high meteorological model (4 km) resolution, especially to reduce temperature model biases. Sound breezes and low-level jets were found to have a critical role in transporting pollutant-rich, shallow marine air masses from the Long Island Sound inland over the Connecticut coast. In addition, modification to the representation of sea surface temperatures improved model results. Regarding ozone levels, study results indicate that synoptic and local meteorological processes can combine to generate the observed complex vertical profiles. The study exposed that there is not a single dominant meteorological circulation pattern that leads to high ozone events and that this complex situation is influenced by a number of competing processes that can create the highly observed structured ozone distributions. This study adds to the growing recognition that ozone pollution in the vicinity of urban areas near large bodies of water can be strongly influenced by small-scale dynamics generated by the land-water interface.

Commenter states under the Appalachian Power precedent, the EPA's modeling and modeling choices must bear a rational relationship to actual data. The D.C. Circuit found in Appalachian Power, "only when the model bears no rational relationship to the characteristics of the data to which it is applied that we will hold that the use of the model was arbitrary and capricious."

Appalachian Power Co. v. EPA, 135 F.3d 791, 802 (D.C. Cir. 1998). Commenter writes that for this reason, the EPA must ensure that its modeling bears a rational relationship with the scientific findings from the LMOS 2017 and LISTOS 2018 studies.

Response:

The EPA disagrees with these comments. While the Lake Michigan Ozone (LMOS) 2019 preliminary report,[110] which describes the analyses of data from the LMOS 2017 field campaign, provides valuable scientific insights into some of the fine-scale meteorological conditions and chemistry that affect the formation and advection of high ozone concentrations onshore from over Lake Michigan, the study was not designed to quantify or evaluate the impacts on ozone exceedances at monitors along the lake from sources in upwind states outside the Lake Michigan area. For instance, during the 2017 LMOS field campaign there were no upwind aircraft or land-based measurements of ozone and precursor concentrations aloft to quantify transport of pollutants into the Lake Michigan area. Also, the April 2019 report is characterized by the authors as "preliminary," and the report notes that meteorological modeling sensitivity tests are on-going. Regarding the use of the Pleim-Xiu Land Surface Model, there is no quantitative information in the report that compares the performance of this method to the NOAH LSM.[111] We do not agree with commenters that the LMOS or LISTOS work establishes that emissions reductions from power plants or other ozone-precursor sources over a large geographic area will not reduce elevated ozone levels at coastal receptor areas. In view of the exploratory nature of the on-going analyses of the LMOS and LISTOS field campaign measurements and modeling, it would be inappropriate and premature for the EPA to change course and change how we develop meteorology for air quality modeling for this final action based on the preliminary information in this report.

Further responses to comments on the relevance of local and regional scale chemical regimes can be found in Section 4.6 and responses to comments on fine-scale modeling in coastal areas and model performance based on fine scale modeling compared to the EPA's 12 km modeling can be found in Section 3.2.2.

11.4 General Support/Opposition

11.4.1 General Support

[110] 2017 Lake Michigan Ozone Study (LMOS) Preliminary Finding Report, April 22, 2019.

https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_v8.pdf

[111] National Centers for Environmental Prediction, Oregon State University, Air Force, Hydrology Lab-NWS (Noah) Land-Surface Model (LSM) User's Guide (May 2011). https://www.jsg.utexas.edu/noah-mp/files/Users_Guide_v0.pdf

Comment:

Commenters (0216, 0247, 0248, 0257, 0259, 0260, 0265, 0273, 0276, 0277, 0285, 0293, 0318, 0332, 0352, 0379, 0384, 0388, 0402, 0492, 0502, 0510,0627, 0635, 0637, 0638, 0642, 0713, 0724, 0727, 0776, 0880, 0885) write in support of the proposed rule.

Response:

Thank you for your comments in support of the proposed rule.

Comment:

Commenters (0248, 0257, 0259, 0260, 0265, 0402) support the EPA's finding that 26 upwind states are significantly contributing to downwind states' nonattainment or interfering with maintenance of the 2015 ozone NAAQS.

Response:

Thank you for your comment. The EPA is making a finding that emissions from 23 upwind states are significantly contributing to downwind states' nonattainment or interference with maintenance of the 2015 ozone NAAQS.

Comment:

Commenters (0260, 0277, 0293, 0379, 0402) support EPA's proposed NO_X emissions budget for EGUs in 25 states.

Response:

Thank you for your comment. The EPA proposed NO_X emissions budgets for 25 states and is finalizing NO_X emissions budgets beginning in the 2023 control period for 22 states listed in Section I.A.1 of the preamble.

Comment:

Commenters (0260, 0277, 0379, 0402) support the EPA's proposed NO_X emissions standard for non-EGUs in selected industries in 23 states.

Response:

Thank you for your comment. The EPA proposed NO_X emissions standards for 23 states and is finalizing emissions limitations or other control requirements for specified industrial sources in 20 states listed in Section I.A.2 of the preamble.

Comment:

Commenters (0247, 0318, 0352, 0402, 0492, 0502) support the inclusion of sources that were not in previous rules, like the inclusion of daily backstops, EGUs without installed controls, and non-EGUs.

Commenter (0318) states that the EPA's proposed FIP seeks to align emissions reductions from upwind sources with statutory attainment deadlines for downwind ozone nonattainment areas, in keeping with multiple court decisions, and the commenter supports this. The commenter also supports the EPA's use of a uniform threshold of 1 percent of the ozone NAAQS to establish linkages between upwind state emissions and downwind ozone nonattainment areas and agrees with the direction the EPA is taking in quantifying "significant contributions" to downwind ozone nonattainment using higher marginal cost thresholds for installing controls. The commenter recognizes and appreciates the proposed FIP's intent to encourage the optimal running of installed controls on a daily basis, in addition to meeting an ozone season cap. In addition, the commenter (0318), along with commenter (0530) support including industrial non-EGU sources that emit large amounts of NO_X. The commenter (0318) encourages the EPA to include municipal waste combustors in the final FIP, which a recent analysis by the commenter indicates can achieve large reductions in NO_X emissions below the $7,500/ton cost threshold used with the other non-EGU source sectors.

Response:

Thank you for your comment. The EPA is finalizing daily backstop emissions rates and requiring emissions performance levels commensurate with specified control installation, as described in Section VI.B of the preamble. The EPA is finalizing emissions limitations and control requirements for industrial sources, as described in Section VI.C of the preamble.

Comment:

Commenters (0402, 0502) support the timelines for compliance, including the immediate requirement to optimized existing control technologies as well as the 2026 timeline for sources to complete retrofits to meet the established mass-based limits.

Response:

Thank you for your comment**.** The EPA is finalizing the compliance timelines for NO_X emissions reductions described in Section VI.A of the preamble.

Comment:

Commenter (0423) writes in support of the proposed rule on behalf of the following organizations:

- 350.org
- Air Alliance Houston
- Appalachian Voices
- Bexar County Green Party
- Black Millennials 4 Flint
- Bridging The Gap, Inc.
- California Communities Against Toxics
- Center for Biological Diversity

- Center for Community Action and Environmental Justice
- Central California Asthma Collaborative
- Change the Chamber
- Chesapeake Climate Action Network
- Citizens for Pennsylvania's Future (PennFuture)
- Clean Air Action Network of Glens Falls (NY)
- Clean Air Council
- Climate Changemakers
- Climate Crisis Policy
- Common Defense
- Deep South Center for Environmental Justice
- Downwinders at Risk Education Fund
- Earthjustice
- Earthworks
- Ecolibrium3
- Elevate
- Endangered Species Coalition
- Environment America
- Environment Texas
- Environmental Defense Fund
- Environmental Justice Committee, AAPI Equity Alliance
- Evergreen Action
- First Focus on Children
- Fort Bend CAN
- Fort Bend County Houston Environmental Organization
- Grassroots Environmental Education
- Green Party of Texas
- Green The Church
- GreenLatinos (National)
- GreenLatinos Colorado

- Health Care Without Harm
- Healthy Environment Alliance of Utah
- Hispanic Access Foundation
- Hispanic Federation
- Indivisible
- Indivisible TX Lege
- Inland Congregations United for Change (ICUC)
- Interfaith Power & Light
- Labadie Environmental Organization (LEO)
- League of Conservation Voters
- Liveable Arlington
- Medical Society Consortium on Climate & Health
- Michigan Clinicians for Climate Action
- Michigan Sustainable Business Forum
- Midlothian Breathe
- Missouri Interfaith Power & Light
- MN350
- Moms Clean Air Force
- National Wildlife Federation
- Natural Resources Defense Council
- NC Clinicians for Climate Action
- No Coal in Oakland
- Northeast Ohio Black Health Coalition
- o2 Utah
- Oregon Environmental Council
- Peoples Collective for Environmental Justice
- Physicians for Social Responsibility
- Poder Latinx
- Resilient Cities and Communities
- Respiratory Health Association

- San Pedro & Peninsula Homeowners Coalition
- Sierra Club
- SLC Air Protectors
- South-Central Partnership for Energy Efficiency as a Resource- SPEER
- Southern Alliance for Clean Energy
- Southern Utah Wilderness Alliance
- Stone in the Stream (Environmental Writers and Artists)
- Sunrise Movement
- The Climate Reality Project
- The Earth Bill Network
- The Honorable Jackie Biskupski, 35th Mayor of Salt Lake City
- U.S. PIRG
- Union of Concerned Scientists
- Unlimited Potential
- Utah Citizens Advocating Renewable Energy (UCARE)
- Utah Tar Sands Resistance
- Voices for Progress
- Warehouse Worker Resource Center (WWRC)
- Waterway Advocates
- West Michigan Sustainable Business Forum
- Western Resource Advocates
- WildEarth Guardians

Response:

Thank you for your comment.

Comment:

Commenter (0758) supports the rule and asserts that interstate pollution contributes significantly to ongoing difficulty attaining and maintaining the 2015 ozone standards across the United States, and provides data to support an assertion that ozone problems are worsening in several locations, including the following:

“With few large stationary sources of ozone pollution of its own, Washington DC is almost exclusively reliant on remedying interstate transport to attain the standard. The Capital was in attainment according to its 2020 DV but, as with other eastern U.S. sites, emissions in 2020 were reduced as a result of COVID. Two DC sites' 2019 DVs exceeded the standard. Connecticut's ozone pollution also persists with 8 monitoring sites' 2020 DVs above the standard."

Commenter (0758) also identifies there is a "stark" need for the rule. After pointing to examples of Connecticut and Wisconsin, the commenter concludes that "Not every nonattainment or maintenance monitor is equally influenced by upwind state emissions. Indeed, for some, the upwind contribution is a considerably smaller fraction of the total ozone levels. However, to fulfill its obligations under the good neighbor provision, 42 U.S.C. § 7410(a)(2)(D)(i)(I), the EPA must address all significant ozone linkages, and as illustrated by the above examples, this rule is acutely needed for those states that contribute so little to their own nonattainment."

Commenter (0758) also asserts that emissions from oil-and-gas activities are increasingly contributing to interstate ozone pollution, particularly in west Texas and southern New Mexico. The commenter supports EPA for taking a first step to address this industry's contribution to cross-state pollution in this rule and urge the Agency to strengthen those portions of this rule.

Response:

The EPA acknowledges the support of the commenter. CAA section 110(a)(2)(D)(i)(I) is designed to address interstate transport and requires that SIPs or FIPs contain adequate provisions prohibiting, consistent with the provisions of Title I of the CAA, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to a NAAQS.

Comments related to non-EGU controls are addressed in Section 4.3.6 (Non-EGUs).

Comment:

Commenter (0388) is pleased to see the EPA include additional industrial sources of air pollution and also the additional western states of Nevada, Utah and Wyoming, in the proposal. The commenter states that this geographic coverage will help ensure that even more downwind states are able to maintain clean air, ensuring that more Americans, regardless of where they live, are able to breathe a little easier. The commenter also states that while fossil fuel power plants are a primary source of NOx, limiting pollution from additional sources like cement kilns, iron and steel boilers, glass furnaces, and chemical and petroleum boilers will help deliver even greater benefits to our communities and the environment. The commenter also appreciates the innovative approach to compliance outlined in the proposal that requires emitters who pollute beyond their limits after the emissions control technology has been put in place to surrender NOx allowances at a rate of 3:1. According to the commenter, the proposal allows flexibility for regulated entities without concentrating pollution in specific areas that already have poor air quality.

11.4.2 General Opposition

Comment:

Commenters (0286, 0505, 0764) express concern that portions of the proposed rule are not legally justified and that the EPA has failed to demonstrate its authority to follow the course of action laid out in the proposed rule.

Response:

All aspects of the final rule are legally justified. The EPA provides additional responses to comments about legal authority in Section III of the preamble and Section 1 (Legal Issues with the EPA's Good Neighbor Plan FIPs).

Comment:

Commenter (0315) adds that the proposed strategies for NO_X emissions reductions are not as effective as the EPA claims according to the tabular data presented in the proposed rule. Commenter (0764) states that the proposal relies on "a porous and faulty record riddled with basic but large cumulative emissions inventory errors."

Response:

The commenter does not provide evidence to support the claim that the rule's NO_X mitigation strategies will not be as effective as described in the proposed rule and the NO_X Mitigation Strategies Proposed Rule TSD. The EPA concludes the technical support documents and other documents included in the docket for this rulemaking present a thorough technical record that is appropriate to support this final rule, including the 2016v3 Emissions Modeling TSD.

Comment:

Commenter (0321) writes that the rule includes "confusingly worded requirements" that are "unclear and contradictory." In a similar comment, commenter (0764) further describes the proposed rule as "inconsistent and vague."

Response:

The EPA does not agree that the rule's requirements are confusingly worded, unclear, or contradictory. Sections VI.B and VI.C of the preamble provide explanations of the regulatory requirements established by this rule. The requirements finalized by this rule are consistent with the EPA's 4-step interstate transport framework for addressing interstate transport obligations, as described in Section III of the preamble.

Comment:

Commenter (0323) writes that the EPA "has erred in assessing control requirements for EGUs and non-EGUs and in redefining the EGU emissions trading program."

Response:

The EPA does not agree with this characterization of the Agency's assessment of control requirements for EGUs and non-EGUs. We provide responses to specific comments regarding control requirements in Sections VI.B and VI.C of the preamble and Section 5

(Implementation of Emissions Reductions). Responses to comments regarding the EGU emissions trading program revised by this rule are provided in Section VI.B.1.d of the preamble and Section 5.2.1 (Group 3 Trading Program).

Comment:

Commenter (0402) requests that the rule be expanded to cover more states and units.

Response:

As described in the overall rule approach (Section III of the preamble), this rule addresses interstate transport obligations for the 2015 ozone NAAQS for all states. The EPA followed the 4-step interstate transport framework to identify emissions reductions necessary to eliminate significant contribution from upwind states contributing above the 1 percent threshold to downwind areas of concern identified using air quality modeling. The states and units subject to FIP requirements established by this rulemaking reflect the EPA's combined technical and policy assessment based on following the four analytic steps.

Comment:

Commenter (0435) writes that the proposed rule lacks technical justification for emissions controls on large industry, "which is especially apparent in the NO_X standards outlined for large industries."

Response:

The EPA does not agree that the rule lacks technical justification for emissions controls in industrial sources. Responses to specific comments on non-EGU control requirements are provided in Section V.C of the preamble and Sections 2, 5, and 10 of this document.

11.5 Executive Order (EO) Sections

11.5.1 Federalism (EO 13132)

11.5.1.1 States' Role in SIPs

Comment:

Commenter (0359) states that the proposed FIP has federalism implications because it will have substantial direct effects on the states, and it changes the distribution of power and responsibilities between the federal government and the states. The commenter pointed to further details of this assertion in the comment letter's non-EGU section. The commenter further states that West Virginia is in attainment with all NAAQS and is not a member state of the Ozone Transport Region (OTR). The commenter explains that RACT is a control stringency required for areas that are not in attainment with the NAAQS or for Ozone Transport Region (OTR) member states. What is considered a reasonable cost for required RACT level control for states located within the OTR, does not carry the same "reasonableness" criteria for states that do not require RACT level control and are not located within the OTR. This is not an equitable assessment to apply the same basis for non-OTR states.

Response:

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. This rule is consistent with the CAA as well as the Federalism Executive Order. We note that Section 11 of E.O. 13132 makes clear that the Order does not "create any right or benefit, substantive or procedural, enforceable at law by a party against the United States, its agencies, its officers, or any person."

The commenter claims that RACT-level controls should not be applied in West Virginia for this rule because the State is in attainment with all NAAQS and is not a member state of the OTR. However, Step 1 of the 4-Step interstate transport framework is based upon that identification of downwind receptors expected to have problems attaining or maintaining the NAAQS. In Step 2, upwind states are identified by determining which states are linked to these downwind air quality problems.

Furthermore, 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 NOx 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 on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA is establishing NOx 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.

The emissions control requirements finalized in this rule for non-EGU industry sources in those upwind states are generally commensurate with the stringency of emissions controls many downwind states have already required of similar sources located within ozone nonattainment areas or in the northeastern OTR pursuant to RACT requirements for NOx. In addition to NOx RACT examples, the EPA's review and determination of cost-effective achievable emissions reductions from non-EGU industrial sources in this action was also informed by review of permits, CDs, NSPS, and other sources of information. See the Final Rule Non-EGU Sectors TSD for more information.

The EPA addresses comments related to the "cooperative federalism" structure of the Clean Air Act in Section 1 of this document (Legal Comments on the EPA's Good Neighbor Plan).

11.5.2 Other Executive Orders

11.5.2.1 Executive Orders- Environmental Justice Expectations

Comments:

Commenter (0323) states that the EPA is obligated to incorporate EJ principles into its actions pursuant to Executive Orders 12898 and 14008.

Commenter (0346) writes that the proposed rule would shift the economic burden of regulatory compliance onto communities of color, low-income populations, and residents of rural areas by causing significant increases in electricity prices that will be imposed on South Texas residents. Commenter points to Executive Orders 12898, 14008, and 13985, which together require federal agencies to make EJ part of their missions, create tools and councils related to EJ, and calls for agencies to identify and address inequities in their policies and programs. Commenter argues that "the federal government's effort to address environmental justice concerns requires federal agencies to treat all communities equally, including communities of color, low income groups, and rural populations and to ensure that these communities do not bear a disproportionate share of the negative impacts, including economic burdens, associated with federal agency actions."

Commenter (0367) explains that Executive Order 12898 directs federal agencies to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on populations of color and low-income populations. Because children and adults of color, Native Americans, and children in families living below the poverty line have higher rates of asthma than the average population, these groups have a higher potential for ozone related health impacts. Black adults also experienced up to three times as many deaths per capita from cardiovascular disease than their White counterparts, and EPA has previously acknowledged that evidence suggests a causal relationship between ozone exposure and cardiovascular effects. Commenter adds that ozone exposure has been linked to worse health outcomes from COVID-19, which disproportionately affected people of color, especially Black Americans. Commenter concludes that in light of the evidence that these populations are disproportionately harmed by ozone, the EPA has an obligation to enact protections and should consider strengthening the proposed rule to further reduce this burden.

Response:

To accompany the final rule, the EPA prepared the Regulatory Impact Analysis for Final Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard. Chapter 7, *Environmental Justice Impacts* of the RIA, discusses how the Agency assessed environmental justice concerns associated with concentrations of ozone from affected EGUs (electrical generating units) and non-EGUs (or other stationary source emissions sources). Section X, *Statutory and Executive Orders Reviews,* in the Preamble discusses how the environmental justice directives of Executive Order 12898 *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* were addressed in the final rule. Section 6-609 of E.O. 12898 makes clear that the Order does not create any "right, benefit, or trust responsibility" and compliance or noncompliance with the Order is not subject to judicial review.

11.5.2.2 Executive Orders (EOs)- Cost and Benefits

Comments:

Commenter (0538) explains that EO 12866 directs federal agencies to incorporate equity considerations into their cost-benefit analyses and regulatory decisions, specifically recognizing that "distributional impacts" and equity" are relevant to assessing net benefits. Commenter also notes that Executive Order 13563 reaffirms EO 12866 and stated that agencies conducting cost-benefit analysis "may consider (and discuss qualitatively) values that are difficult or impossible to quantify, including equity, human dignity, fairness, and distributional impacts." Commenter concludes that "EPA should treat any desirable (or undesirable) distributional effects as an unquantified benefit (or cost) that it compares alongside other costs and benefits."

Commenter (0765) points to EO 12866, requiring the consideration of all costs and benefits, including global impacts, and EO 13990, instructing agencies to take global damages into account. Commenter writes that the EPA should draw upon these legal authorities in further explaining its reliance on global climate damage valuations.

Response:

In compliance with the cited executive orders, 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 the Preamble. We note that compliance with these executive orders is not enforceable at law. *See*, E.O. 13990 sec. 8; E.O. 13563 sec. 7; E.O. 12866 sec. 10.

Comments:

Commenters (0359, 0400) strongly disagree with EPA's assertion that this action (as defined under EO 13211) 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 commenters note that the EPA has prepared a "Statement of Energy Effects" to describe the effects of certain regulatory actions on energy supply, distribution, or use and briefly restate assertions made – *e.g.*, there will be a 1 percent change in retail electricity prices on average across the contiguous U.S. in 2025.

Response:

The EPA disagrees with the commenters' assertion that this action is a "significant energy action." Executive Order 13211 *Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use* defines a "significant energy action" as an action that "promulgates or is expected to lead to the promulgation of a final rule or regulation" (and normally published in the *Federal Register*), including notices of inquiry, advance notices of proposed rulemaking and notices of proposed rulemaking, and that is:

- A significant regulatory action under Executive Order 12866 (or successor order) that is likely to have a significant adverse effect on the supply, distribution or use of energy (see next section for determining "significant adverse energy effect"); or
- Designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

Per EO 13211, one example of a "significant adverse energy effect" is an increase in the cost of energy production in excess of 1 percent. As described in Section X. *Statutory and Executive Orders Reviews* of the Preamble, the EPA determined that 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, which does not exceed the 1 percent threshold established pursuant to EO 13211 guidance. Further details of the estimated energy effects are presented in Chapter 4 of the RIA, which is in the public docket.

Section 5 of E.O. 13211 makes clear that the Order "does not create any right or benefit, substantive or procedural, enforceable at law by a party against the United States, its agencies, its officers, or any person."

11.6 Incorporate Others' Comments

Comments:

Commenter (0286) endorses the comments submitted by the APPA and MOG.

Commenter (0302) refers to comments submitted by "EEI and the Class of '85."

Commenter (0305) supports the comments made by APPA and American Municipal Power (AMP).

Commenter (0306) supports and incorporates the comments of the Texas Commission on

Environmental Quality, and Public Utility Commission of Texas, and the ERCOT.

Commenter (0313) supports the following comments submitted to the EPA:

- Arkansas Department of Energy and Environment
- Arkansas Electric Cooperative Corporation
- American Forest and Paper Association
- Entergy Arkansas
- National Council for Air and Stream Improvement
- The McQueen Firm PLLC on behalf of Select Tier 2 Arkansas Sources
- Midwest Ozone Group

Commenter (0319) supports and endorses the technical work undertaken by Alpine Geophysics and a combination of electric industry consultants, Cichanowicz and Marchetti, on behalf of MOG and the comments submitted by MOG.

Commenter (0323) supports comments submitted by AF&PA, American Iron and Steel Institute (AISI), Steel Manufacturers Association, the Specialty Steel Industry of North America, and the states of Kentucky, West Virginia, Arkansas, Missouri, Mississippi, Tennessee, Alabama, and Oklahoma.

Commenter (0330) supports and incorporates comments submitted by Edison Electric Institute, Power Generators Air Coalition, and the American Gas Association.

Commenter (0333) supports and incorporates all comments submitted by the Texas Commission on Environmental Quality. Commenter also references the comments submitted by Entergy Texas, Inc.

Commenter (0338) adopts by reference the comments of the American Forest & Paper Association.

Commenter (0342) endorses the positions of the Midwest Ozone Group and the Ohio Utilities and Generators Group.

Commenter (0346) adopts and incorporates comments submitted by the NRECA.

Commenter (0349) supports and incorporates the comments submitted by the MOG, the Ohio Electric Association, the Indiana Utilities Group, and the Power Generators Air Coalition (PGen).

Commenter (0360) supports and endorses comments submitted by the Steel Manufacturers Association.

Commenters (0364, 0404, 0540) support comments shared by the Arkansas Municipal Power Association.

Commenters (0368, 0531) support and endorse the comments filed by the Midwest Ozone

Group.

Commenter (0354) endorses the Texas Transport Working Group's comments and incorporates them by reference. Commenter also concurs with the comments submitted by the Electricity Reliability Council of Texas, the Public Utility Commission of Texas, and Texas Commission on Environmental Quality.

Commenter (0357) supports the comments provided by APPA and the Large Public Power Council (LPPC).

Commenter (0372) supports and incorporates comments submitted by the MOG, the NRECANRECA, and UIEK.

Commenter (0381) endorses comments submitted made by the Midwest Ozone Group, National Rural Electric Cooperative Association, and the American Public Power Association (Technical Comments on the Electric Generating Unit Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule, June 17, 2022).

Commenter (0395) supports comments submitted by the APPA, the LPPC, the Association of Electric Companies of Texas (AECT), the Public Utility Commission of Texas (PUCT), ERCOT, and the TCEQ.

Commenter (0396) incorporates by reference the comments submitted by Louisiana Electric Utility Environmental Group (LEUEG).

Commenter (0405) endorses and incorporates by reference the comments submitted by AISI and MOG.

Commenter (0411) supports comments submitted by AECT, the Texas Transport Working Group, the Minnesota Chamber of Commerce, and the Wisconsin Manufacturers Council. Commenter also incorporates technical critiques of EPA's proposed cost-effectiveness assumptions performed by Sargent and Lundy and Alpine Geophysics.

Commenter (0420) endorses and adopts the comments submitted by the National Mining Association.

Commenter (0429) supports the comments submitted by INGAA.

Commenter (0431) incorporates comments submitted by the NRECA, the Class of '85 Regulatory Response Group, the Energy and Environmental Alliance of Arkansas, and the Arkansas Environmental Federation.

Commenter (0495) references comments submitted by MOG and PGen.

Commenter (0499) adopts and incorporates by reference comments submitted by LEUEG and the Louisiana Chemical Association.

Commenter (0503) references comments submitted by the Ozone Transport Commission.

Commenter (0504) supports the comments submitted by the Air Stewardship Coalition and

MOG.

Commenter (0508) supports the comments submitted by the Oklahoma Secretary of Energy and Environment, the Oklahoma Department of Environmental Quality, and the State of Oklahoma.

Commenter (0511) supports and incorporates by reference the comments submitted by MOG and EEI.

Commenter (0516) incorporates a report by Ramboll titled "Evaluation and Critique of EPA's Proposed Good Neighbor Plan for the 2015 Ozone NAAQS" that was submitted in support of the Air Stewardship Coalition's comments.

Commenter (0517) incorporates by reference the comments submitted by Oklahoma Secretary of Energy & Environment Kenneth Wagner and the DEQ on April 22, 2022, and June 21, 2022.

Commenter (0521) supports the Technical Comments on Electric Generating Unit Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule prepared for the Midwest Ozone Group, National Rural Electric Cooperative Association, and the American Public Power Association dated June 2022.

Commenter (0532) supports and endorses comments submitted by NRECA.

Commenter (0552) incorporates by reference the comments of the Louisiana Chemical Association.

Commenter (0555) references comments submitted by the Arkansas Forest & Paper Council (AF&PC), Albemarle Chemical Company (Albemarle), and U.S. Lime & Minerals (USLM).

Commenter (0557) supports and endorses comments submitted by the American Chemistry Council, American Forest and Paper Association, and the Air Stewardship Coalition.

Commenter (0761) supports comments by the American Chemical Council and the Louisiana Chemical Association.

Commenter (0764) supports comments submitted by the Arkansas Department of Energy & Environment and MOG.

Response:

The EPA responds to these comments in other sections of this document. Refer to the table of commenter names and docket identification numbers in Appendix A.

11.7 Out of Scope Comments

Comment:

Commenter (0502) states the current standard of 70 ppb is not adequately protective of human health and although not in the scope of this rule, the commenter proposes 60 ppb.

Response:

Comments regarding revising an existing National Ambient Air Quality Standard are not in scope for this rulemaking.

Comments:

Commenter (0758) argues that the EPA should not rely on the proposed rule to exempt sources from reasonable progress [under the regional haze program of the CAA]. The commenter states that the proposed rule does little to reduce haze-causing NO_X pollution outside of the ozone season, but the CAA and Regional Haze Rule mandate that states make reasonable progress toward natural visibility on both the most and least impaired visibility days throughout the year. According to the commenter, since direct NO_X emissions and particulate nitrate are important contributors to haze in the western and upper central region of the United States, particularly during winter, the proposed reduction of NO_X emissions only during the ozone season cannot substitute for the emissions reductions necessary to make reasonable progress at all Class I areas throughout the year. The commenter adds that in many Class I areas, sulfur dioxide is also a dominant contributor to haze pollution, and because the proposed rule does nothing to address SO_2 pollution, it cannot substitute for a reasoned analysis of the four statutory reasonable progress factors states must consider in evaluating reasonable progress.

Commenter (0758) continues, in developing comprehensive haze SIP revisions for the second planning period, states cannot rely on unenforceable, so-called "on-the-way" pollution reduction measures, such as the proposed rule's yet-to-be finalized emissions budgets. The CAA requires that "[e]ach state implementation plan . . . shall" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act. 42 U.S.C. § 7410(a)(2)(A). The Regional Haze Rule similarly requires each state to include "enforceable emissions limitations" as necessary to ensure reasonable progress toward the national visibility goal. This means that any so-called "on-the-way" measures, including anticipated emissions reductions under this rule or any shutdowns or reductions in a source's emissions or utilization, "must be included in the SIP" as enforceable emissions reduction measures.

Response:

This rule does not exempt sources from any regulatory requirements, including reasonable progress toward natural visibility, related to implementation of regional haze rules under the CAA. Comments regarding sources in Class I areas, SO_2 pollution, regional haze SIP revisions, or requirements to include anticipated emissions reductions under the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards as "on-the-way" measures for the Regional Haze Rule, are not in scope for this rulemaking.

Comments:

Commenter (0798) incorporates by reference several comments submitted on EPA's proposed SIP denials (Dockets: EPA-R05-OAR-2022-0006-0017 and EPA-R06-OAR-2021-0801-0043) as well as the comments submitted by the State of Arkansas on EPA's proposed denial of Arkansas's SIP.

Response:

This comment is not in scope for this rulemaking.

Comments:

Commenter (0395) lists the following scientific reports, which were cited in the comments "incorporated by reference:"

- A report prepared by J. Edward Cichanowicz, James Marchetti, Michael C. Hein, and Shirley Rivera prepared for APPA and others and submitted by APPA in this docket (APPA Study)
- A report prepared by Sonoma Technology dated submitted to this docket by Baker Botts on behalf of AECT and others (Sonoma Report)
- A technical memorandum prepared by Sargent & Lundy submitted to this docket by Baker Botts on behalf of AECT and others (Sargent & Lundy Technical Memorandum).

Commenter (0347) incorporates comments by Armstrong Cement from 2017 on the Ozone Transport Commission's White Paper on Control Measures for Nitrogen Oxides Emissions from Two Source Categories.

Response:

The content of these reports has been addressed elsewhere in this document or the preamble to the extent that they raised issues related to this rulemaking with reasonable specificity.

Comments:

Commenter (0398) incorporates by reference the comments submitted by the Arkansas Department of Energy and Environment on EPA's disapproval of Arkansas's SIP and includes them as an Appendix.

Commenter (0760) incorporates by reference comments submitted by the Louisiana Department of Environmental Quality and the Louisiana Chemical Association on EPA's proposed disapproval of the Louisiana SIP (Docket: EPA-R06-OAR-2021-0801).

Response:

Comments on the SIP disapproval action (88 FR 9336) are not in scope of this rulemaking. Where commenters have identified with reasonable specificity how an issue raised with respect to the SIP disapproval action relates to an issue in this rulemaking and is in scope of this rulemaking, the Agency has addressed those comments.

Appendix A

List of “Unique” Commenters by Docket ID Number

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0002	Comment submitted by Wisconsin Department of Natural Resources (WDNR)	Government State
0003	Comment submitted by Midwest Ozone Group	Industry/Trade Association
0004	Comment submitted by Earthjustice et al.	Non-profit, Public Health & Environmental Advocacy Group
0005	Comment submitted by Air Pollution Control Program, Missouri Department of Natural Resources	Government State
0006	Comment submitted by Maryland Department of the Environment (MDE)	Government State
0197	Comment submitted by Baker Botts, LLP	Industry/Trade Association
0198	Comment submitted by Midwest Ozone Group (MOG)	Industry/Trade Association
0199	Comment submitted by Gibson Blankenship	Private Citizen
0200	Comment submitted by Ohio Utilities and Generators Group (OUG)	Industry/Trade Association
0201	Comment submitted by Portland Cement Association (PCA)	Industry/Trade Association
0202	Comment submitted by Tiffany Hartung	Private Citizen
0203	Comment submitted by Salsa Test	Private Citizen
0204	Comment submitted by John Jay	Private Citizen
0205	Comment submitted by Baker Botts, LLP	Industry/Trade Association
0206	Comment submitted by David Jay	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0207	Comment submitted by Jennifer Young	Private Citizen
0208	Comment submitted by Steel Manufacturers Association (SMA)	Industry/Trade Association
0209	Comment submitted by Texas Commission on Environmental Quality (TCEQ)	Government State
0210	Comment submitted by Specialty Steel Industry of North America (SSINA)	Industry/Trade Association
0211	Comment submitted by Division of Environmental Quality (DEQ), Arkansas Department of Energy and Environment	Government State
0212	Comment submitted by The Evangelical Environmental Network	Other Advocacy Group
0213	Comment submitted by Virginia Department of Environmental Quality (DEQ)	Government State
0214	Comment submitted by National Parks Conservation Association (NPCA)	Non-profit, Public Health & Environmental Advocacy Group
0215	Comment submitted by Maryland Department of the Environment (MDE)	Government State
0216	Comment submitted by Alliance of Nurses for Healthy Environments (ANHE)	Non-profit, Public Health & Environmental Advocacy Group
0217	Comment submitted by Manijeh Berenji	Private Citizen
0218	Comment submitted by Jennifer DeRose	Private Citizen
0219	Comment submitted by Jeanette Mott Oxford	Private Citizen
0221	Comment submitted by American Iron and Steel Institute (AISI)	Industry/Trade Association
0222	Comment submitted by Central States Air Resource Agencies Association (CenSARA)	Other Advocacy Group

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0223	Comment submitted by Mothers & Others For Clean Air	Non-profit, Public Health & Environmental Advocacy Group
0224	Comment submitted by NRG Texas Power LLC	Industry/Trade Association
0231	Comment submitted by Air Stewardship Coalition	Industry/Trade Association
0232	Comment submitted by The Association of Air Pollution Control Agencies (AAPCA)	Non-profit, Public Health & Environmental Advocacy Group
0233	Comment submitted by Wyoming Department of Environmental Quality (WDEQ)	Government State
0234	Comment submitted by Franziska Rosser	Private Citizen
0235	Comment submitted by Mojave Desert Air Quality Management District (MDAQMD)	Government Tribal
0237	Comment submitted by California Cement Manufacturers Environmental Coalition (CCMEC)	Industry/Trade Association
0238	Comment submitted by Basin Electric Power Cooperative	Other Advocacy Group
0239	Comment submitted by Oklahoma Department of Environmental Quality (ODEQ)	Government State
0240	Comment submitted by Regional Air Quality Council (RAQC)	Non-profit, Public Health & Environmental Advocacy Group
0241	Comment submitted by Midwest Ozone Group (MOG)	Industry/Trade Association
0242	Comment submitted by Marie Winter	Private Citizen
0243	Comment submitted by Corteva Agriscience, LLC	Industry/Trade Association
0244	Comment submitted by United States Steel Corporation (USS)	Industry/Trade Association
0245	Comment submitted by Portland Cement Association (PCA)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0246	Comment submitted by Anna Jane Doe	Private Citizen
0247	Comment submitted by League of Women Voters of Metro St. Louis (LWV)	Non-profit, Public Health & Environmental Advocacy Group
0248	Comment submitted by Metropolitan Washington Council of Governments (MWCOG), Metropolitan Washington Air Quality Committee (MWAQC)	Non-profit, Public Health & Environmental Advocacy Group
0256	Comment submitted by Tim Maurer	Private Citizen
0257	Comment submitted by Keweenaw Bay Indian Community	Government Tribal
0258	Comment submitted by Air Stewardship Coalition (ASC)	Industry/Trade Association
0259	Comment submitted by Ute Mountain Ute Tribe	Government Tribal
0260	Comment submitted by Department of Natural Resources, Mille Lacs Band of Ojibwe	Government Tribal
0261	Comment submitted by David Bezanson	Private Citizen
0262	Comment submitted by Texas Public Policy Foundation (TPPF)	Other Advocacy Group
0263	Comment submitted by Evangelical Environmental Network and Young Evangelicals for Climate Action	Non-profit, Public Health & Environmental Advocacy Group
0264	Comment submitted by Unions for Jobs & Environmental Progress (UJEP)	Other Advocacy Group
0265	Comment submitted by Lizbeth Gomez	Private Citizen
0266	Comment submitted by Ohio Environmental Protection Agency (Ohio EPA)	Government State
0267	Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC). (web)	Mass Mailer
0268	Comment submitted by Damon Bishop	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0269	Comment submitted by Bert Greenberg	Private Citizen
0271	Comment submitted by Kyle Hoffman, Kansas State Representative et al.	Government State
0272	Comment submitted by National Grid	Industry/Trade Association
0273	Comment submitted by Climate and Environmental Health Committee of the Pennsylvania Chapter of the American Academy of Pediatrics (PA AAP)	Non-profit, Public Health & Environmental Advocacy Group
0274	Comment submitted by Seward Generation, LLC	Industry/Trade Association
0275	Comment submitted by WEC Energy Group, Inc.	Industry/Trade Association
0276	Comment submitted by Central Texas Clean Air Coalition (CAC), Capital Area Council of Governments (CAPCOG)	Industry/Trade Association
0277	Comment submitted by Missouri Coalition for the Environment (MCE)	Non-profit, Public Health & Environmental Advocacy Group
0278	Comment submitted by CalPortland Company	Industry/Trade Association
0279	Comment submitted by Alabama Department of Environmental Management (ADEM)	Government State
0280	Comment submitted by Nucor Corporation	Industry/Trade Association
0281	Comment submitted by California Air Resources Board (CARB)	Government State
0282	Comment submitted by Environmental Energy Alliance of New York, LLC (EEANY), Independent Power Producers of New York (IPPNY)	Industry/Trade Association
0283	Comment submitted by Manitowoc Public Utilities (MPU)	Industry/Trade Association
0284	Comment submitted by Industrial Minerals Association – North America (IMA-NA)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0285	Comment submitted by Chris Larson, Wisconsin State Senate	Government State
0286	Comment submitted by City of Springfield, Illinois, Office of Public Utilities, d/b/a City Water, Light and Power (CWLP)	Government Local
0287	Comment submitted by AMG Vanadium LLC	Industry/Trade Association
0288	Comment submitted by Consolidated Edison Company of New York (Con Edison)	Industry/Trade Association
0289	Comment submitted by Air Pollution Control Program, Missouri Department of Natural Resources	Government State
0290	Comment submitted by CPS Energy	Industry/Trade Association
0291	Comment submitted by Roger Caiazza	Private Citizen
0292	Comment submitted by Gregory Pagliuzza	Private Citizen
0293	Comment submitted by Fresh Energy	Non-profit, Public Health & Environmental Advocacy Group
0294	Comment submitted by TimkenSteel Corporation	Industry/Trade Association
0295	Comment submitted by Mojave Desert Air Quality Management District (MDAQMD)	Government Local
0296	Comment submitted by Physicians for Social Responsibility Wisconsin et al.	Non-profit, Public Health & Environmental Advocacy Group
0297	Comment submitted by Grand River Dam Authority (GRDA)	Other Advocacy Group
0298	Comment submitted by Globe Metallurgical, Inc.	Industry/Trade Association
0299	Comment submitted by Holcim (US) Inc.	Industry/Trade Association
0300	Comment submitted by Mississippi Department of Environmental Quality	Government State

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0301	Comment submitted by Minnesota Resource Recovery Association (MRRA)	Industry/Trade Association
0302	Comment submitted by Evergy, Inc.	Industry/Trade Association
0303	Comment submitted by California Cement Manufacturers Environmental Coalition (CCMEC)	Industry/Trade Association
0304	Comment submitted by Prairie Lakes Municipal Solid Waste Authority (PLMSWA)	Government Local
0305	Comment submitted by City of Orrville, Ohio	Government Local
0306	Comment submitted by Office of the Texas Attorney General	Government State
0307	Comment submitted by Kohler Company	Industry/Trade Association
0308	Comment submitted by Newport News Shipbuilding (NNS), A division of HII	Industry/Trade Association
0309	Comment submitted by Delaware City Refining Company LLC	Industry/Trade Association
0310	Comment submitted by Madison Gas and Electric (MGE)	Industry/Trade Association
0313	Comment submitted by Arkansas Environmental Federation (AEF)	Non-profit, Public Health & Environmental Advocacy Group
0314	Comment submitted by Petroleum Association of Wyoming (PAW)	Industry/Trade Association
0315	Comment submitted by Wyoming Mining Association (WMA)	Industry/Trade Association
0316	Comment submitted by Sheboygan Ozone Reduction Alliance (SORA)	Non-profit, Public Health & Environmental Advocacy Group
0317	Comment submitted by Energy and Environmental Alliance of Arkansas (EEAA)	Industry/Trade Association
0318	Comment submitted by Ozone Transport Commission (OTC)	Other Advocacy Group

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0319	Comment submitted by Indiana Energy Association (IEA); and Indiana utility Group (IUG)	Industry/Trade Association
0320	Comment submitted by Genesis Alkali Wyoming, LP	Industry/Trade Association
0321	Comment submitted by Vitro Flat Glass LLC and Vitro Meadville Flat Glass, LLC	Industry/Trade Association
0322	Comment submitted by Kentucky Chamber of Commerce	Government State
0323	Comment submitted by Midwest Ozone Group (MOG)	Industry/Trade Association
0324	Comment submitted by Wisconsin Department of Natural Resources (WDNR)	Government State
0325	Comment submitted by Anson Koch	Private Citizen
0326	Comment submitted by Division of Air Pollution Control, Tennessee Department of Environment & Conservation	Government State
0327	Comment submitted by West Virginia Coal Association et al.	Industry/Trade Association
0328	Comment submitted by Pennsylvania Department of Environmental Protection	Government State
0329	Comment submitted by Minnesota Pollution Control Agency (MPCA) et al.	Government State
0330	Comment submitted by CMS Energy Corporation	Industry/Trade Association
0331	Comment submitted by Minnesota Chamber of Commerce	Industry/Trade Association
0332	Comment submitted by Edison Electric Institute (EEI)	Industry/Trade Association
0333	Comment submitted by Public Utility Commission of Texas (PUCT)	Industry/Trade Association
0334	Comment submitted by Texas Pipeline Association (TPA)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0335	Comment submitted by Christopher Lish	Private Citizen
0336	Comment submitted by Virginia Department of Environmental Quality (DEQ)	Government State
0337	Comment submitted by Anchor Hocking Holdings Inc.	Industry/Trade Association
0338	Comment submitted by Wisconsin Paper Council (WPC)	Industry/Trade Association
0339	Comment submitted by Evangelical Environmental Network (EEN)	Non-profit, Public Health & Environmental Advocacy Group
0340	Comment submitted by Energy and Environment Cabinet, Commonwealth of Kentucky	Government State
0341	Comment submitted by Utility Information Exchange of Kentucky (UIEK)	Industry/Trade Association
0342	Comment submitted by Buckeye Power, Inc.	Industry/Trade Association
0343	Comment submitted by National Council for Air and Stream Improvement (NCASI)	Non-profit, Public Health & Environmental Advocacy Group
0344	Comment submitted by Indiana Department of Environmental Management (IDEM)	Government State
0345	Comment submitted by Felman Production, LLC et al.	Industry/Trade Association
0346	Comment submitted by South Texas Electric Cooperative, Inc. (STEC)	Other Advocacy Group
0347	Comment submitted by Armstrong Cement & Supply	Industry/Trade Association
0348	Comment submitted by Midcontinent Independent System Operator (MISO)	Industry/Trade Association
0349	Comment submitted by Ohio Valley Electric Corporation (OVEC), Indiana-Kentucky Electric Corporation (IKEC)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0350	Comment submitted by Kinder Morgan, Inc.	Industry/Trade Association
0351	Comment submitted by Southern Minnesota Municipal Power Agency (SMMPA)	Industry/Trade Association
0352	Comment submitted by District of Columbia Department of Energy and Environment (DOEE)	Government State
0353	Comment submitted by GPA Midstream Association	Industry/Trade Association
0354	Comment submitted by Association of Electrical Companies of Texas (AECT)	Industry/Trade Association
0355	Comment submitted by Louisiana Public Service Commission	Government State
0356	Comment submitted by Owens Corning (OC)	Industry/Trade Association
0357	Comment submitted by American Municipal Power, Inc. (AMP) and Ohio Municipal Electric Association (OMEA)	Industry/Trade Association
0358	Comment submitted by Environment America et al.	Non-profit, Public Health & Environmental Advocacy Group
0359	Comment submitted by West Virginia Department of Environmental Protection (DEP)	Government State
0360	Comment submitted by JSW Steel (USA) Inc. and JSW Steel USA Ohio, Inc.	Industry/Trade Association
0361	Comment submitted by Indiana Municipal Power Agency (IMPA)	Industry/Trade Association
0362	Comment submitted by Council of Industrial Boiler Owners (CIBO)	Industry/Trade Association
0363	Comment submitted by Arkansas Municipal Power Association (AMPA)	Industry/Trade Association
0364	Comment submitted by Jonesboro, City Water & Light (CWL)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0365	Comment submitted by State of Louisiana Department of Environmental Quality	Government State
0366	Comment submitted by Eastern Generation, LLC	Industry/Trade Association
0367	Comment submitted by Attorneys General of New York et al.	Government State
0368	Comment submitted by Ohio Utilities and Generators Group (OUG)	Industry/Trade Association
0369	Comment submitted by Clean Wisconsin	Other Advocacy Group
0370	Comment submitted by Southwest Power Pool, Inc. (SPP)	Industry/Trade Association
0371	Comment submitted by INNIO Waukesha Gas Engines, Inc. (INNIO Waukesha)	Industry/Trade Association
0372	Comment submitted by East Kentucky Power Cooperative, Inc. (EKPC)	Other Advocacy Group
0373	Comment submitted by America's Power	Industry/Trade Association
0374	Comment submitted by Covanta Energy, LLC	Industry/Trade Association
0375	Comment submitted by Arkansas Public Service Commission (APSC)	Industry/Trade Association
0376	Comment submitted by EES Coke Battery, L.L.C.	Industry/Trade Association
0377	Comment submitted by North American Insulation Manufacturers Association (NAIMA)	Industry/Trade Association
0378	Comment submitted by Utah Petroleum Association (UPA) and Utah Mining Association (UMA)	Industry/Trade Association
0379	Comment submitted by American Lung Association et al.	Non-profit, Public Health & Environmental Advocacy Group
0380	Comment submitted by TC Energy	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0381	Comment submitted by Sikeston Board of Municipal Utilities (SBMU)	Government Local
0382	Comment submitted by Kentucky Attorney General Office et al.	Government State
0383	Comment submitted by Nevada Division of Environmental Protection (NDEP)	Government State
0384	Comment submitted by Gregory Pagliuzza	Private Citizen
0385	Comment submitted by San Miguel Electric Cooperative, Inc.	Other Advocacy Group
0386	Comment submitted by National Lime Association (NLA)	Industry/Trade Association
0387	Comment submitted by Moon Lake Electric Association, Inc. (MLEA)	Other Advocacy Group
0388	Comment submitted by Evergreen Action	Non-profit, Public Health & Environmental Advocacy Group
0389	Comment submitted by Sylvia Oliva	Private Citizen
0390	Comment submitted by Maureen Allen	Private Citizen
0391	Comment submitted by Susan Kallman	Private Citizen
0392	Anonymous public comment	Private Citizen
0393	Comment submitted by Jennifer Russell	Private Citizen
0394	Comment submitted by American Public Power Association (APPA)	Industry/Trade Association
0395	Comment submitted by Lower Colorado River Authority (LCRA)	Non-profit, Public Health & Environmental Advocacy Group
0396	Comment submitted by Cleco Corporate Holdings LLC	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0397	Comment submitted by Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ)	Government State
0398	Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality	Government State
0399	Comment submitted by United Steelworkers (USW)	Industry/Trade Association
0400	Comment submitted by National Mining Association (NMA)	Industry/Trade Association
0401	Comment submitted by American Foundry Society (AFS)	Other Advocacy Group
0402	Comment submitted by National Tribal Air Association (NTAA)	Government Tribal
0403	Comment submitted by Southern California Gas Company (SoCalGas)	Industry/Trade Association
0404	Comment submitted by West Memphis Utility Commission (WMUC)	Industry/Trade Association
0405	Comment submitted by Cleveland-Cliffs Inc.	Industry/Trade Association
0406	Comment submitted by Ardagh Glass Inc.	Industry/Trade Association
0407	Comment submitted by Mississippi Public Service Commission	Government State
0408	Comment submitted by LG&E and KU Energy LLC	Industry/Trade Association
0409	Comment submitted by National Rural Electric Cooperative Association (NRECA)	Other Advocacy Group
0410	Comment submitted by Southwest Power Pool Regional State Committee, Inc. (SPP RSC)	Industry/Trade Association
0411	Comment submitted by Xcel Energy	Industry/Trade Association
0412	Comment submitted by PJM Interconnection, L.L.C.	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0413	Comment submitted by Electric Reliability Council Of Texas, Inc. (ERCOT) et al.	Industry/Trade Association
0414	Comment submitted by Large Public Power Council (LPPC)	Industry/Trade Association
0415	Comment submitted by Associated General Contractors of America (AGC)	Industry/Trade Association
0416	Comment submitted by American Iron and Steel Institute (AISI)	Industry/Trade Association
0417	Comment submitted by TATA Chemicals (Soda Ash) Partners	Industry/Trade Association
0418	Comment submitted by Anchor Glass Container Corporation	Industry/Trade Association
0419	Comment submitted by City of Painesville	Government Local
0420	Comment submitted by Utah Mining Association (UMA)	Industry/Trade Association
0421	Comment submitted by Dow Chemical Company	Industry/Trade Association
0422	Comment submitted by Chemours Company	Industry/Trade Association
0423	Comment submitted by 350.org et al.	Non-profit, Public Health & Environmental Advocacy Group
0424	Comment submitted by NAAQS Regulatory Review & Rulemaking (NR3) Coalition	Industry/Trade Association
0425	Comment submitted by Claire Richards	Private Citizen
0426	Comment submitted by Nora Pfeiffer	Private Citizen
0427	Comment submitted by Metropolitan Congregations United	Non-profit, Public Health & Environmental Advocacy Group
0428	Comment submitted by Western States Air Resources Council (WESTAR)	Other Advocacy Group

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0429	Comment submitted by American Gas Association (AGA)	Industry/Trade Association
0430	Comment submitted by Northern Indiana Public Service Company LLC (NIPSCO)	Industry/Trade Association
0431	Comment submitted by Arkansas Electric Cooperative Corporation (AECC)	Other Advocacy Group
0432	Comment submitted by Pixelle Specialty Solutions LLC	Industry/Trade Association
0433	Comment submitted by Connecticut Department of Energy and Environmental Protection (DEEP)	Government State
0434	Comment submitted by Electric Reliability Council of Texas, Inc. (ERCOT)	Industry/Trade Association
0435	Comment submitted by Senator Shelley Moore Capito	Government Federal
0436	Comment submitted by Utah Department of Environmental Quality (UDAQ)	Government State
0437	Comment submitted by American Forest & Paper Association (AF&PA)	Industry/Trade Association
0438	Comment submitted by Greg Golz	Private Citizen
0439	Comment submitted by David Richards	Private Citizen
0440	Comment submitted by Barb Foerster	Private Citizen
0441	Comment submitted by Nicole Rosa	Private Citizen
0442	Comment submitted by Jennifer Barton	Private Citizen
0443	Comment submitted by Skylar Casey	Private Citizen
0444	Comment submitted by Mark Walker	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0445	Anonymous public comment	Private Citizen
0446	Comment submitted by Rich Elam	Private Citizen
0447	Comment submitted by Margaret Tilden	Private Citizen
0448	Comment submitted by John Commerford	Private Citizen
0449	Comment submitted by Jean Maust	Private Citizen
0450	Comment submitted by Todd Gutmann	Private Citizen
0451	Comment submitted by Julie Serwer	Private Citizen
0452	Comment submitted by Sharon Burke	Private Citizen
0453	Comment submitted by J. Cohen	Private Citizen
0454	Comment submitted by Alicelia Warren	Private Citizen
0455	Comment submitted by Kathleen Wiechman	Private Citizen
0456	Comment submitted by Zachariah Love	Private Citizen
0457	Comment submitted by Diana Nasser	Private Citizen
0458	Comment submitted by Mark Meeks	Private Citizen
0459	Comment submitted by Debra Dunson	Private Citizen
0460	Comment submitted by George Yaffe	Private Citizen
0461	Comment submitted by Nancy Campbell	Private Citizen
0462	Anonymous public comment	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0463	Comment submitted by Katharine Barrett	Private Citizen
0464	Comment submitted by Judith Bentley	Private Citizen
0465	Comment submitted by Todd Snyder	Private Citizen
0466	Comment submitted by Joseph E Sangster Slave family	Private Citizen
0467	Anonymous public comment	Private Citizen
0468	Comment submitted by Fred Kraybill	Private Citizen
0469	Comment submitted by Nora Ziegler	Private Citizen
0470	Comment submitted by J. T. Smith	Private Citizen
0471	Comment submitted by Edna Scheifele	Private Citizen
0472	Comment submitted by Ruth Sheets	Private Citizen
0473	Comment submitted by John Six	Private Citizen
0474	Comment submitted by A. Brennan	Private Citizen
0475	Comment submitted by Jan Peischl	Private Citizen
0476	Comment submitted by Daniel Safer	Private Citizen
0477	Comment submitted by Robert Bruckman	Private Citizen
0478	Comment submitted by Pamela Haines	Private Citizen
0479	Comment submitted by Dorothea Leicher	Private Citizen
0480	Comment submitted by Sabrina Fedel	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0481	Comment submitted by Char Magaro	Private Citizen
0482	Comment submitted by Maddison Crezee	Private Citizen
0483	Comment submitted by Linda Zeveloff	Private Citizen
0484	Comment submitted by Celeste Kelty	Private Citizen
0485	Comment submitted by David Rogers	Private Citizen
0486	Comment submitted by Sabrina Kirby	Private Citizen
0487	Comment submitted by Diane Selvaggio	Private Citizen
0488	Comment submitted by Joanne Kreil	Private Citizen
0489	Comment submitted by Joseph Kenosky	Private Citizen
0490	Comment submitted by Laura Lane	Private Citizen
0491	Anonymous public comment	Private Citizen
0492	Comment submitted by Environmental Defense Fund (EDF) (Part 1 of 3)	Non-profit, Public Health & Environmental Advocacy Group
0495	Comment submitted by American Electric Power (AEP)	Industry/Trade Association
0496	Comment submitted by John Young	Private Citizen
0497	Comment submitted by Jake Assae	Private Citizen
0498	Comment submitted by Voices for Progress	Non-profit, Public Health & Environmental Advocacy Group
0499	Comment submitted by Louisiana Electric Utility Environmental Group (LEUEG)	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0500	Comment submitted by Southern Company	Industry/Trade Association
0501	Comment submitted by Interstate Natural Gas Association of America (INGAA)	Industry/Trade Association
0502	Comment submitted by American Thoracic Society (ATS)	Non-profit, Public Health & Environmental Advocacy Group
0503	Comment submitted by Maryland Department of the Environment (MDE)	Government State
0504	Comment submitted by Steel Manufacturers Association (SMA) and Specialty Steel Industry of North America (SSINA)	Industry/Trade Association
0505	Comment submitted by Texas Commission on Environmental Quality (TCEQ)	Government State
0506	Comment submitted by Constellation Energy Corporation	Industry/Trade Association
0507	Comment submitted by Enbridge Gas Pipelines	Industry/Trade Association
0508	Comment submitted by The Petroleum Alliance of Oklahoma	Industry/Trade Association
0509	Comment submitted by Wyoming Department of Environmental Quality (WDEQ)	Government State
0510	Comment submitted by New York State Department of Environmental Conservation	Industry/Trade Association
0511	Comment submitted by Monongahela Power Company (Mon Power)	Industry/Trade Association
0512	Comment submitted by Idaho Power Company (IPC)	Industry/Trade Association
0513	Comment submitted by Eagle Materials, Inc.	Industry/Trade Association
0514	Comment submitted by Mississippi Silicon LLC (MS Silicon)	Industry/Trade Association
0515	Comment submitted by Calpine Corporation	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0516	Comment submitted by Portland Cement Association (PCA)	Industry/Trade Association
0517	Comment submitted by Environmental Federation of Oklahoma (EFO)	Non-profit, Public Health & Environmental Advocacy Group
0518	Comment submitted by Air Stewardship Coalition (ASC)	Industry/Trade Association
0519	Comment submitted by Oklahoma Gas & Electric Co. (OG&E)	Industry/Trade Association
0520	Comment submitted by Utah Associated Municipal Power Systems (UAMPS)	Industry/Trade Association
0521	Comment submitted by City Utilities of Springfield, Missouri (CU)	Industry/Trade Association
0522	Comment submitted by North American Chapter of the International Society For Environmental Epidemiology (ISEE)	Non-profit, Public Health & Environmental Advocacy Group
0523	Comment submitted by SunCoke Energy, Inc.	Industry/Trade Association
0524	Comment submitted by Tennessee Valley Authority (TVA)	Other Advocacy Group
0525	Comment submitted by Buzzi Unicem USA	Industry/Trade Association
0526	Comment submitted by Solid Waste Association of North America (SWANA)	Industry/Trade Association
0527	Comment submitted by WE ACT for Environmental Justice	Non-profit, Public Health & Environmental Advocacy Group
0528	Comment submitted by Texas Transport Working Group et al.	Industry/Trade Association
0529	Comment submitted by North Dakota Public Service Commission (NDPSC)	Government State
0530	Comment submitted by The Clean Energy Group (CEG)	Non-profit, Public Health & Environmental Advocacy Group
0531	Comment submitted by Ameren Missouri	Industry/Trade Association

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0532	Comment submitted by Deseret Power Electric Co-operative Association	Industry/Trade Association
0533	Comment submitted by Class of '85 Regulatory Response Group	Industry/Trade Association
0534	Comment submitted by Midcontinent Independent System Operator (MISO)	Other Advocacy Group
0535	Comment submitted by Ellen Dorshow-Gordon	Private Citizen
0536	Comment submitted by City of Piggott, Arkansas Municipal Power Association (AMPA)	Industry/Trade Association
0537	Comment submitted by Buchanan Generation, LLC	Industry/Trade Association
0538	Comment submitted by Institute for Policy Integrity at New York University School of Law	Academia
0539	Comment submitted by Minnesota Power (MP)	Industry/Trade Association
0540	Comment submitted by Conway Corporation	Industry/Trade Association
0541	Comment submitted by PowerSouth Energy Cooperative	Other Advocacy Group
0542	Comment submitted by North American Coal Corporation (NA Coal)	Industry/Trade Association
0543	Comment submitted by League of Conservation Voters	Non-profit, Public Health & Environmental Advocacy Group
0544	Comment submitted by Gavin Power, LLC	Industry/Trade Association
0545	Comment submitted by Wisconsin Manufacturers & Commerce (WMC)	Industry/Trade Association
0546	Comment submitted by Entergy Services, LLC (ESL)	Industry/Trade Association
0547	Comment submitted by Basin Electric Power Cooperative	Other Advocacy Group

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0548	Comment submitted by Glass Packaging Institute (GPI)	Industry/Trade Association
0549	Comment submitted by American Chemistry Council (ACC)	Industry/Trade Association
0550	Comment submitted by The Luminant Companies	Industry/Trade Association
0551	Comment submitted by Power Generators Air Coalition (PGen)	Industry/Trade Association
0552	Comment submitted by Eagle US 2 LLC	Industry/Trade Association
0553	Comment submitted by Duke Energy	Industry/Trade Association
0554	Comment submitted by Berkshire Hathaway Energy Company (BHE)	Industry/Trade Association
0555	Comment submitted by Arkansas Forest & Paper Council (AF&PC) et al.	Industry/Trade Association
0556	Comment submitted by Emery County Board of Commissioners, Utah	Government State
0557	Comment submitted by Virginia Manufacturers Association (VMA)	Industry/Trade Association
0558	Comment submitted by Delaware Department of Natural Resources and Environmental Control (DNREC)	Government State
0559	Comment submitted by David Hill	Private Citizen
0560	Comment submitted by Michael Margulis	Private Citizen
0561	Comment submitted by Jen Vickery	Private Citizen
0562	Comment submitted by Eleanor Dvorak	Private Citizen
0563	Comment submitted by Lawrence Rosin	Private Citizen
0564	Comment submitted by Jeremy Ehrlich	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0565	Comment submitted by Bruce Orluck	Private Citizen
0566	Comment submitted by Susan Gottfried	Private Citizen
0567	Comment submitted by Betty Sabo	Private Citizen
0568	Comment submitted by Melissa Martin	Private Citizen
0569	Comment submitted by Abigail Siddall	Private Citizen
0570	Comment submitted by Perry Kendall	Private Citizen
0571	Comment submitted by Joyce Louis	Private Citizen
0572	Comment submitted by Peter Jones	Private Citizen
0573	Comment submitted by Judith Stanley	Private Citizen
0574	Comment submitted by Karen Nagy	Private Citizen
0575	Comment submitted by Stephanie Childers	Private Citizen
0576	Comment submitted by Judy Lukasiewicz	Private Citizen
0577	Comment submitted by Marcia Hylan	Private Citizen
0578	Comment submitted by Jane Byrnes	Private Citizen
0579	Comment submitted by Jane Byrnes	Private Citizen
0580	Comment submitted by Tina Krauz	Private Citizen
0581	Comment submitted by Tina Krauz	Private Citizen
0582	Comment submitted by Krista Lohr	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0583	Comment submitted by K. Danowski	Private Citizen
0584	Comment submitted by C. L. Bilchak	Private Citizen
0585	Comment submitted by Henry Frank	Private Citizen
0586	Comment submitted by Benita J. Campbell	Private Citizen
0587	Comment submitted by Kathie Westman	Private Citizen
0588	Comment submitted by Richard Burdo	Private Citizen
0589	Comment submitted by Sheila Coughlin	Private Citizen
0590	Comment submitted by Virginia Pannabecker	Private Citizen
0591	Comment submitted by C Scott and Cynthia Bucher	Private Citizen
0592	Comment submitted by Melissa McSwigan	Private Citizen
0593	Comment submitted by Peggy Hasley	Private Citizen
0594	Comment submitted by Dave Shortt	Private Citizen
0595	Comment submitted by Lora Redweik	Private Citizen
0596	Comment submitted by Cheryl Champy	Private Citizen
0597	Comment submitted by Karen Collins	Private Citizen
0598	Comment submitted by Sarah Hill	Private Citizen
0599	Comment submitted by Emma Vagelos	Private Citizen
0600	Comment submitted by Yesenia Chavez	Private Citizen

Document ID **EPA-HQ-OAR-2021-0668-XXX**	**Commenter Name, Organization/Affiliation**	**Commenter Type**
0601	Comment submitted by Ellie Georgeson	Private Citizen
0602	Comment submitted by Sophia Cifolelli	Private Citizen
0603	Comment submitted by Ava Milliken	Private Citizen
0604	Comment submitted by Rishabh Raman	Private Citizen
0605	Comment submitted by Abigail Waldron	Private Citizen
0606	Comment submitted by Eric Sullivan	Private Citizen
0607	Comment submitted by Donna Marie Korba	Private Citizen
0608	Comment submitted by Dylan Bry	Private Citizen
0609	Comment submitted by Sarah Richardson	Private Citizen
0610	Comment submitted by Jon Esty	Private Citizen
0611	Comment submitted by Miranda Schor	Private Citizen
0612	Comment submitted by Anna Richardson	Private Citizen
0614	Comment submitted by Lauren Salomon	Private Citizen
0615	Comment submitted by Nicholas Littlejohn	Private Citizen
0616	Comment submitted by Nicholas Littlejohn	Private Citizen
0617	Comment submitted by Andy Moser	Private Citizen
0618	Comment submitted by Ed Mitchell	Private Citizen
0619	Comment submitted by Lucy Stroock	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0620	Comment submitted by Niki Gold	Private Citizen
0621	Comment submitted by Phil Glosserman	Private Citizen
0622	Comment submitted by Sarah Gao	Private Citizen
0623	Comment submitted by Lyn Lowry	Private Citizen
0624	Comment submitted by Cat Ransom	Private Citizen
0625	Comment submitted by Andrew Payton	Private Citizen
0626	Comment submitted by Cara Cook	Private Citizen
0627	Comment submitted by Peter Crownfield, Coordinator, Alliance for Sustainable Communities - Lehigh Valley	Non-profit, Public Health & Environmental Advocacy Group
0628	Comment submitted by LaTricea Adams, President, Black Millennials 4 Flint	Non-profit, Public Health & Environmental Advocacy Group
0629	Comment submitted by Tucker Richards	Private Citizen
0630	Comment submitted by Natalie Guarin	Private Citizen
0631	Comment submitted by CMC Solutions, LLC	Industry/Trade Association
0632	Comment submitted by Aman Sardana,	Private Citizen
0633	Comment submitted by David Landis, President, Landis Communications	Industry/Trade Association
0634	Comment submitted by Ann Violi	Private Citizen
0635	Comment submitted by Nathan Martin, Board member, Pennsylvania Interfaith Power and Light	Non-profit, Public Health & Environmental Advocacy Group
0636	Comment submitted by Rosalinda Heayn	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0637	Comment submitted by Janet Weyker, Eco-Justice Center Director at Racine Dominicans	Non-profit, Public Health & Environmental Advocacy Group
0638	Comment submitted by Yvonne Besyk, Coalition Member, Clean Power Coalition of Southeast WI	Non-profit, Public Health & Environmental Advocacy Group
0639	Comment submitted by Diane Lehner	Private Citizen
0640	Comment submitted by Zinzi Konig	Private Citizen
0641	Comment submitted by Walter Tsou, Board of Directors, Physicians for Social Responsibility PA	Non-profit, Public Health & Environmental Advocacy Group
0642	Comment submitted by Jeremy Gragert, City Council Member, City of Eau Claire	Government Local
0643	Comment submitted by Jen Schneidman Partica, College Farm and Community Garden Manager, Bucknell University	Academia
0644	Comment submitted by Andrew Stuhl, Professor and Chair, Environmental Studies and Sciences, Bucknell University	Academia
0645	Comment submitted by Douglas Holmes	Private Citizen
0646	Comment submitted by Doug Bland, Executive Director, Arizona Interfaith Power & Light	Non-profit, Public Health & Environmental Advocacy Group
0647	Mass Comment Campaign sponsoring organization unknown. Sample attached (web)	Mass Mailer
0648	Mass Comment Campaign sponsoring organization unknown. Sample attached (web)	Mass Mailer
0649	Mass Comment Campaign sponsoring organization unknown. Sample attached (web)	Mass Mailer
0650	Mass Comment Campaign sponsoring organization unknown. Sample attached (web)	Mass Mailer
0651	Mass Comment Campaign sponsoring organization unknown. Sample attached (web)	Mass Mailer

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0652	Mass Comment Campaign sponsored by Climate Action Campaign. (web)	Mass Mailer
0653	Mass Comment Campaign sponsored by National Wildlife Federation Action Fund. (web)	Mass Mailer
0654	Mass Comment Campaign sponsored by The Climate Reality Project. (web)	Mass Mailer
0655	Mass Comment Campaign sponsored by Environment America and U.S. PIRG. (web)	Mass Mailer
0656	Mass Comment Campaign sponsored by Climate Action Campaign. (web)	Mass Mailer
0657	Mass Comment Campaign sponsored by Climate Action Campaign. (web)	Mass Mailer
0658	Mass Comment Campaign sponsored by Climate Action Campaign. (web)	Mass Mailer
0659	Mass Comment Campaign sponsored by Environmental Defense Fund. (web)	Mass Mailer
0660	Mass Comment Campaign sponsored by Climate Action Campaign. (web)	Mass Mailer
0661	Mass Comment Campaign sponsored by Evergreen Action. (web)	Mass Mailer
0662	Comment submitted by Andy Moser	Private Citizen
0663	Comment submitted by Diane Lehner	Private Citizen
0664	Comment submitted by Kate Siegel	Private Citizen
0665	Comment submitted by Chris Durtschi	Private Citizen
0666	Comment submitted by Mar Dore	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0667	Comment submitted by Jackson Green	Private Citizen
0668	Comment submitted by Lura Morgan	Private Citizen
0669	Comment submitted by Ray Dean	Private Citizen
0670	Comment submitted by Kristin Edmark MPH RD	Private Citizen
0671	Comment submitted by C. Purchase	Private Citizen
0672	Comment submitted by Jon Esty	Private Citizen
0673	Comment submitted by Laurie Lohrer	Private Citizen
0674	Comment submitted by Geralyn Leannah	Private Citizen
0675	Comment submitted by Martine Divito	Private Citizen
0676	Comment submitted by Daphna Ezrachi	Private Citizen
0677	Comment submitted by Amanda Senechal	Private Citizen
0678	Comment submitted by John Binder	Private Citizen
0679	Comment submitted by Mary Ann and Frank Graffagnino	Private Citizen
0680	Comment submitted by Noga Shemer	Private Citizen
0681	Comment submitted by Sophia Westwood	Private Citizen
0682	Comment submitted by Kevin Cianfarini	Private Citizen
0683	Comment submitted by Joy Reeves	Private Citizen
0684	Comment submitted by Olga Kachook	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0685	Comment submitted by Terry Burns	Private Citizen
0686	Comment submitted by Todd Sack	Private Citizen
0687	Comment submitted by Mickey Hadick	Private Citizen
0688	Comment submitted by Christy Folk	Private Citizen
0689	Comment submitted by Adrian Keller	Private Citizen
0690	Comment submitted by Erick Allen	Private Citizen
0691	Comment submitted by Howard Watts	Private Citizen
0692	Comment submitted by Dennis Sullivan	Private Citizen
0693	Comment submitted by Kurtis Purtee	Private Citizen
0694	Comment submitted by Jill Mitchler	Private Citizen
0695	Comment submitted by David Fott	Private Citizen
0696	Comment submitted by Rebecca Gill	Private Citizen
0697	Comment submitted by Austin Wang	Private Citizen
0698	Comment submitted by Tiffany Howard	Private Citizen
0699	Comment submitted by Bruce Hockersmith	Private Citizen
0700	Comment submitted by Sharon Furlong	Private Citizen
0701	Comment submitted by Stew Friedman	Private Citizen
0702	Comment submitted by Julie Quinn	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0703	Comment submitted by Andrea Ketchum	Private Citizen
0704	Comment submitted by Shannon Staton-Growcock	Private Citizen
0705	Comment submitted by Joseph Geierman, Mayor, City of Doraville, GA	Government Local
0706	Comment submitted by Robert Dewey	Private Citizen
0707	Comment submitted by James Van Nostrand, Charles M. Love, Jr. Endowed Professor, WVU College of Law, Center for Energy & Sustainable Development	Academia
0708	Comment submitted by Julie Kennedy	Private Citizen
0709	Comment submitted by Leena Varghese	Private Citizen
0710	Comment submitted by Melissa Jakubik	Private Citizen
0711	Comment submitted by Morgan Park	Private Citizen
0712	Comment submitted by Lisa Jordan	Private Citizen
0713	Comment submitted by Monica Kruse, La Crosse County Board Chair	Government Local
0714	Comment submitted by Michael Hancock, Mayor, City and County of Denver, Colorado	Government Local
0715	Comment submitted by Tanya Frazee, Board Member, Georgia Interfaith Power & Light	Non-profit, Public Health & Environmental Advocacy Group
0716	Comment submitted by Gary Garrett	Private Citizen
0717	Comment submitted by Irene Burga	Private Citizen
0718	Comment submitted by Tina Wilkinson	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0719	Comment submitted by Genevieve Silva	Private Citizen
0720	Comment submitted by Elizabeth Del Buono	Private Citizen
0721	Comment submitted by Alan Peterson	Private Citizen
0722	Comment submitted by Lee Anzicek, Chair - Sierra Club Crossroads Group	Non-profit, Public Health & Environmental Advocacy Group
0723	Comment submitted by Lee Burton	Private Citizen
0724	Comment submitted by Ron Kardos, Conservation Chair, Sierra Club	Non-profit, Public Health & Environmental Advocacy Group
0725	Comment submitted by Kindra Weid, Coalition Coordinator, MI Air MI Health	Non-profit, Public Health & Environmental Advocacy Group
0726	Comment submitted by Yvonne Besyk	Private Citizen
0727	Comment submitted by David Heayn-Menendez, Lewisburg, PA Councilman	Government Local
0728	Comment submitted by Robert Jantzen	Private Citizen
0729	Comment submitted by Mark Giese	Private Citizen
0730	Anonymous public comment	Private Citizen
0731	Comment submitted by Yaniv Aronson	Private Citizen
0732	Comment submitted by Alan Peterson	Private Citizen
0733	Comment submitted by Debra Rowe, President, US Partnership for Education for Sustainable Development	Non-profit, Public Health & Environmental Advocacy Group
0734	Comment submitted by Nina Jacobs	Private Citizen
0735	Comment submitted by Donald Brandt	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0736	Comment submitted by Marc Buathier-Phillips	Private Citizen
0737	Comment submitted by Emily Daggar	Private Citizen
0738	Comment submitted by Kyra Walker	Private Citizen
0739	Comment submitted by Evey Mengelkoch	Private Citizen
0740	Comment submitted by Hunter Mundy	Private Citizen
0741	Comment submitted by Phyllis Blumberg, PA Jewish Earth Alliance	Private Citizen
0742	Comment submitted by Lauren Ebersik	Private Citizen
0743	Comment submitted by Mandana Nakhai	Private Citizen
0744	Comment submitted by Larry Bathgate	Private Citizen
0745	Comment submitted by James Boone	Private Citizen
0746	Comment submitted by Lorraine Wilson	Private Citizen
0747	Comment submitted by Robin Haine	Private Citizen
0748	Comment submitted by Alan Goldhammer	Private Citizen
0749	Comment submitted by Kathleen Colwill	Private Citizen
0750	Comment submitted by Carol Siewert	Private Citizen
0751	Comment submitted by Jesse Kelly	Private Citizen
0752	Comment submitted by Mark Gathany	Private Citizen
0753	Comment submitted by Jill Aquino	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0754	Comment submitted by Alex Dudek	Private Citizen
0755	Comment submitted by Christina Haag	Private Citizen
0756	Comment submitted by David Rieck	Private Citizen
0757	Comment submitted by Beyond Plastics et al.	Non-profit, Public Health & Environmental Advocacy Group
0758	Comment submitted by Earthjustice et al. (Part 1 of 2)	Non-profit, Public Health & Environmental Advocacy Group
0760	Comment submitted by Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA)	Industry/Trade Association
0761	Comment submitted by Eastman Chemical Company	Industry/Trade Association
0763	Comment submitted by Fenceline Watch	Non-profit, Public Health & Environmental Advocacy Group
0764	Comment submitted by Arkansas Forest and Paper Council (AF&PC), Albemarle Chemical, and Arkansas Lime Company	Industry/Trade Association
0765	Comment submitted by Center for Biological Diversity et al.	Non-profit, Public Health & Environmental Advocacy Group
0766	Comment submitted by Peggy Chaikin	Private Citizen
0767	Comment submitted by Emily Halliday	Private Citizen
0768	Comment submitted by James Hubbard	Private Citizen
0769	Comment submitted by Nancy Kullman	Private Citizen
0770	Comment submitted by Chris Dietrich	Private Citizen
0771	Comment submitted by Sarah Star	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0772	Comment submitted by Peter Bakken	Private Citizen
0773	Comment submitted by Naomi Davidson	Private Citizen
0774	Comment submitted by David Pedersen	Private Citizen
0775	Comment submitted by Anna Tursich	Private Citizen
0776	Comment submitted by Russell Kilsch, President, Founder & Owner of Lakefront Brewery in Milwaukee, WI.	Industry/Trade Association
0777	Comment submitted by Nicole Marcot	Private Citizen
0778	Comment submitted by Irena Meilutyte	Private Citizen
0779	Comment submitted by Talen Energy	Industry/Trade Association
0780	Comment submitted by Reverend Jeffrey Thomas, Interfaith Power and Light	Non-profit, Public Health & Environmental Advocacy Group
0781	Comment submitted by Irena Meilutyte	Private Citizen
0782	Comment submitted by Black Hills Energy (BHE)	Industry/Trade Association
0783	Comment submitted by Cathy Chamblee	Private Citizen
0784	Comment submitted by Gwen Jaspers	Private Citizen
0785	Comment submitted by Angela Collins	Private Citizen
0786	Comment submitted by Ann Violi	Private Citizen
0787	Comment submitted by Gwen Jaspers	Private Citizen
0789	Comment submitted by Era Flowers	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0790	Comment submitted by Noah Guthrie	Private Citizen
0791	Comment submitted by Silvio Mazzella Jr.	Private Citizen
0792	Comment submitted by Lonnie Ellis	Private Citizen
0793	Comment submitted by Stella C.	Private Citizen
0794	Comment submitted by Maria Nelly M.	Private Citizen
0795	Comment submitted by Lourdes H.	Private Citizen
0796	Comment submitted by Cesar R.	Private Citizen
0797	Comment submitted by Jose A.	Private Citizen
0798	Comment submitted by United States Steel Corporation (U.S. Steel)	Industry/Trade Association
0799	Comment submitted by Yuli S.	Private Citizen
0800	Comment submitted by Lucia P.	Private Citizen
0801	Comment submitted by Claudia G.	Private Citizen
0802	Comment submitted by Javier G.	Private Citizen
0803	Comment submitted by Maria G.	Private Citizen
0804	Comment submitted by Josiah C.	Private Citizen
0805	Comment submitted by Yanneth M.	Private Citizen
0806	Comment submitted by David Hardee	Private Citizen
0807	Comment submitted by Joshua Miller	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0808	Comment submitted by Hayley Walker	Private Citizen
0809	Comment submitted by Katherine Meyer	Private Citizen
0810	Comment submitted by Carol Goodwin	Private Citizen
0811	Comment submitted by Jeremy Fryberger	Private Citizen
0812	Comment submitted by Lindy Moceus	Private Citizen
0813	Comment submitted by John Gau	Private Citizen
0814	Comment submitted by Brenda Frey	Private Citizen
0815	Comment submitted by Michael Wherley	Private Citizen
0816	Comment submitted by Lisa Ruckman	Private Citizen
0817	Comment submitted by Clark Oehler	Private Citizen
0818	Comment submitted by Beth Grahn	Private Citizen
0819	Comment submitted by Dwight Johnson	Private Citizen
0820	Comment submitted by Justin Grover	Private Citizen
0821	Comment submitted by John Fischer	Private Citizen
0822	Comment submitted by Elaine Thomas	Private Citizen
0823	Comment submitted by Jean Naples	Private Citizen
0824	Comment submitted by Sharon Tkacz	Private Citizen
0825	Comment submitted by Julia Tullis	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0826	Comment submitted by Lisa VanLaanen	Private Citizen
0827	Comment submitted by Lynn Fergusson	Private Citizen
0828	Comment submitted by Mark Barone	Private Citizen
0829	Comment submitted by Calvin Hilton	Private Citizen
0830	Comment submitted by Heather Schlaff	Private Citizen
0831	Comment submitted by Erin Dalessandro	Private Citizen
0832	Comment submitted by Blythe Clark-McKitrick	Private Citizen
0833	Comment submitted by Kathleen Worley	Private Citizen
0834	Comment submitted by Sharon Livesey	Private Citizen
0835	Comment submitted by Dr. James Perkins, President, Progressive National Baptist Church	Non-profit, Public Health & Environmental Advocacy Group
0836	Comment submitted by Schree Wade	Private Citizen
0837	Anonymous public comment	Private Citizen
0838	Comment submitted by Don Lipmanson	Private Citizen
0839	Comment submitted by Jean Liedl	Private Citizen
0840	Comment submitted by Rebecca Cutting	Private Citizen
0841	Comment submitted by Ann May	Private Citizen
0842	Comment submitted by Cortrell Adams	Private Citizen
0843	Comment submitted by Robert A. Mertz	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0844	Comment submitted by Nick Littlejohn	Private Citizen
0845	Comment submitted by Erin Moore	Private Citizen
0846	Comment submitted by Carol Steinhart	Private Citizen
0847	Comment submitted by Breeze Azrael	Private Citizen
0848	Comment submitted by Sandy Dillon	Private Citizen
0849	Comment submitted by Ellen Cox	Private Citizen
0850	Comment submitted by Joe Lervold	Private Citizen
0851	Comment submitted by Charlot Taylor	Private Citizen
0852	Comment submitted by Kris Erkiletian	Private Citizen
0853	Comment submitted by Carol Brock	Private Citizen
0854	Comment submitted by Melissa Carlson	Private Citizen
0855	Comment submitted by Diane Fails	Private Citizen
0856	Comment submitted by Kathy Kahn	Private Citizen
0857	Comment submitted by Suzan Fleischman	Private Citizen
0858	Comment submitted by Marcia Gustafson	Private Citizen
0859	Comment submitted by Craig Zarling	Private Citizen
0860	Comment submitted by Amy Benesch	Private Citizen
0861	Comment submitted by Nick Burns	Private Citizen

Document ID **EPA-HQ-OAR-2021-0668-XXX**	**Commenter Name, Organization/Affiliation**	**Commenter Type**
0862	Comment submitted by Roxana Mejia	Private Citizen
0863	Comment submitted by Hispanic Access Foundation	Non-profit, Public Health & Environmental Advocacy Group
0864	Comment submitted by Lillian Farrell, President, Sussex County School Nurses Association	Non-profit, Public Health & Environmental Advocacy Group
0865	Comment submitted by Tim Brainerd	Private Citizen
0866	Comment submitted by Kathleen Quandt	Private Citizen
0867	Comment submitted by Sable Bradshaw	Private Citizen
0868	Comment submitted by Kabyn Vikesland	Private Citizen
0869	Comment submitted by Jennifer Barton	Private Citizen
0870	Comment submitted by David Hill	Private Citizen
0871	Comment submitted by Pam Magidson	Private Citizen
0872L	Comment submitted by Alliant Energy Corporation	Industry/Trade Association
0873L	Comment submitted by WEC Energy Group	Industry/Trade Association
0874	Mass Comment Campaign sponsoring organization unknown. (email)	Mass Mailer
0875	Mass Comment Campaign sponsoring organization unknown. (email)	Mass Mailer
0876	Comment submitted by Kayla K (incomplete surname)	Private Citizen
0877	Comment submitted by R KNO_X (incomplete first name)	Private Citizen
0878	Comment submitted by Nick Palumbo	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0879	Comment submitted by Lauren Kuby, Councilmember, City of Tempe	Government State
0880	Comment submitted by Shea Hughes, Director of Business Development, Scale Microgrid Solutions	Industry/Trade Association
0881	Comment submitted by Alice Madden, Executive Director, Getches-Wilkinson Center at Colorado Law	Academia
0882	Comment submitted by Dara Marks Marino, Partnerships Coordinator, WattTime	Non-profit, Public Health & Environmental Advocacy Group
0883	Comment submitted by Yolanda Whyte	Private Citizen
0884	Comment submitted by William Flippin Jr.	Private Citizen
0885	Comment submitted by Rebecca Perkins Kwoka, State Senator for New Hampshire	Government State
0886	Comment submitted by Sandra Moriarty	Private Citizen
0887	Comment submitted by William Ewing	Private Citizen
0888	Comment submitted by Susan Gilpin	Private Citizen
0889	Comment submitted by Squidge L. Davis	Private Citizen
0890	Comment submitted by Robyn Deveney	Private Citizen
0891	Comment submitted by Peter Simmons	Private Citizen
0892	Comment submitted by Nancy Artz	Private Citizen
0893	Comment submitted by John McKee	Private Citizen
0894	Comment submitted by Jean Bass	Private Citizen
0895	Comment submitted by Jake Maier	Private Citizen

Document ID EPA-HQ-OAR-2021-0668-XXX	Commenter Name, Organization/Affiliation	Commenter Type
0896	Comment submitted by Jacquelyn Cressy	Private Citizen
0897	Comment submitted by Franklin Anderson	Private Citizen
0898	Comment submitted by Elizabeth Trice	Private Citizen
0899	Comment submitted by Beth Comeau	Private Citizen
0900	Comment submitted by Linda Shaffer	Private Citizen
0901	Comment submitted by Sandy Scholar	Private Citizen
0902	Comment submitted by Eric Doub	Private Citizen
0903	Comment submitted by Richard Estabrook	Private Citizen
0904	Comment submitted by Susan Wind	Private Citizen
0905	Comment submitted by Joy Sabl	Private Citizen
0906	Comment submitted by Sarah Dennison	Private Citizen
0907	Comment submitted by Adinah Barnett	Private Citizen
0908	Comment submitted by Vivienne Lenk	Private Citizen
0909	Comment submitted by Barbara Peaslee	Private Citizen
0910	Comment submitted by Medea Steinman	Private Citizen
0911	Comment submitted by Nancy Maynes	Private Citizen
0912L	Comment submitted by America's State Coal Ash Association	Industry/Trade Association

Appendix B

List of Mass Comment Campaigns

1. Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC). (web)
2. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
3. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
4. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
5. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
6. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
7. Mass Comment Campaign sponsored by Climate Action Campaign. (web)
8. Mass Comment Campaign sponsored by National Wildlife Federation Action Fund. (web)
9. Mass Comment Campaign sponsored by The Climate Reality Project. (web)
10. Mass Comment Campaign sponsored by Environment America and U.S. PIRG. (web)
11. Mass Comment Campaign sponsored by Climate Action Campaign. (web)
12. Mass Comment Campaign sponsored by Climate Action Campaign. (web)
13. Mass Comment Campaign sponsored by Climate Action Campaign. (web)
14. Mass Comment Campaign sponsored by Environmental Defense Fund. (web)
15. Mass Comment Campaign sponsored by Climate Action Campaign. (web)
16. Mass Comment Campaign sponsored by Evergreen Action. (web)
17. Mass Comment Campaign sponsoring organization unknown. (email)
18. Mass Comment Campaign sponsoring organization unknown. (email)

Appendix C

Sample of Mass Comment Campaigns

1. Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC). (web)
EPA-HQ-OAR-2021-0668-0267

Please accept these 13,853 public comments from members and online activists of the Natural Resources Defense Council (NRDC) asking you to adopt the strongest possible "Good Neighbor Rule" to reduce power plant and industrial pollution that crosses state lines, and secure clean air across the U.S.

Nearly half of the U.S. population breathes unhealthy air every day. Communities of color and low-income communities are disproportionately impacted. And pollution from power plants and other industrial sources are major culprits. This pollution can often travel downwind to neighboring states and impact folks living miles away.

The administration's proposed "Good Neighbor Rule" would rein in cross-state pollution and hold those polluters accountable.

I urge you to move forward with the strongest-possible version of this proposal. Thank you!

2. Mass Comment Campaign sponsoring organization unknown. Sample attached (web)
EPA-HQ-OAR-2021-0668-0648

Dear EPA Administrator Michael Regan,

As an environmentalist whose father has asthma, I would like to thank you for proposing a strong Good Neighbor Rule to reduce dangerous air pollution across the country. It will provide many benefits to our communities, public health, and the environment such as 1,000 avoided premature deaths annually, over one million fewer asthma attacks annually, healthier forests and crops, and improved visibility in our national parks and wild places, not to mention increased mental health.

More than 125 million people live in areas of the country where air pollution exceeds the health standard for ground-level ozone, also known as smog. Thankfully, there usually isn't much air pollution where I live - wildfire smoke notwithstanding - but whenever I go to nearby Los Angeles, there's always that grey haze that simply can't be healthy. Ozone is vital for protecting us from ultraviolet radiation, but that's when it stays in the stratosphere's ozone layer. At ground level, however, it causes asthma attacks, lung damage, and premature death. It also damages plant life, including forests and crops. People of color and low-income people are more likely to work and live in these areas and therefore share a disproportionate share of these harms, as if they didn't have most everything else going against them already.

This proposed rule requires polluters in upwind states that cause unhealthy smog levels in downwind states to clean up. It targets emissions of nitrogen oxides (NO_X), which cause the formation of smog. Reductions in NO_X will not only reduce smog, but also reduce deadly fine particulate levels and slow climate change. The proposed rule requires pollution reduction from fossil fuel-burning plants as well as gas pipelines and several other categories of heavy industry: cement manufacturing, iron and steel mills, glass manufacturing, chemical plants, oil and coal product plants, and paper mills. By internalizing some of the costs of dirty energy and dirty industry, the rule will accelerate the transition to clean alternatives.

I ask again: please finalize this strong proposal and ensure it covers all the states and industries needed to secure cleaner air for millions of people. Thank you for your time, and I hope you follow through with this request.

3. Mass Comment Campaign sponsored by National Wildlife Federation Action Fund. (web)
EPA-HQ-OAR-2021-0668-0653

Hello, I’m writing today to thank this administration for taking swift action to address air quality standards. The cross-state movement of dangerous ozone- and smog-forming pollution makes it difficult for downwind states to reach and maintain important air quality standards. It is vital that these threats to human and wildlife health are addressed in a bold manner. I strongly support the Environmental Protection Agency’s proposed Cross State Air Pollution Rule, also known as the Good Neighbor Plan, which will reduce harmful air pollution from both power plants and industrial facilities through the deployment of existing technologies. In doing so, this highly relevant rule will also protect countless Americans who are unknowingly subjected to dangerous pollution from power plants and industrial facilities in upwind states. Smog and other air pollution can travel across state lines, impacting communities in downwind states, and disproportionately harming those already subjected to poor air quality standards and outdated policies and technology. I would like to see the communities in downwind states regain control over their air quality, which will in turn improve wildlife health. I urge you to quickly finalize this rule as it will not only upgrade air quality regulations, but will improve visibility in national and state parks and increase protection for sensitive ecosystems.

4. Mass Comment Campaign sponsored by The Climate Reality Project. (web)
EPA-HQ-OAR-2021-0668-0654

I support the EPA’s proposed update to the Cross State Air Pollution Rule ("Good Neighbor Plan") to protect the public health from dangerous air pollution. As you know, ozone and smog-forming pollution often sicken people in downwind states that have no power to curb these emissions. Ozone pollution from NO_X emissions contributes to asthma, heart and lung disease, and other respiratory issues. For too long, fossil fuel power plants and industrial facilities have tried to maintain local support by exporting their pollution to other states with enormous smokestacks. It is time that they comply with common sense air quality standards and install pollution control technologies or face closure. Please finalize this proposal to ensure that we can all live healthier and breathe easier.

5. Mass Comment Campaign sponsored by Environment America and U.S. PIRG. (web) EPA-HQ-OAR-2021-0668-0655

Dear EPA Administrator Michael Regan,

We write to you on behalf of Environment America and U.S. PIRG. Thank you for proposing a strong "Good Neighbor Plan" to protect our health from ozone pollution.

As you know, air pollution does not respect state boundaries and downwind states rely on federal action to ensure other states in their region are taking action for clean air. The Cross-State Air Pollution Rule can help limit unhealthy levels of ground-level ozone, or smog, for millions of Americans who live downwind from power plants and industrial facilities.

Addressing smog pollution is critical to human health. Air pollution from fossil fuels alone causes more than 50,000 premature deaths in the United States every single year. When inhaled, smog irritates our airways, increasing our risk of serious heart and lung diseases.

Environment America and U.S. PIRG's Trouble in the Air report found that 57.3 million Americans experienced more than a month of elevated ozone pollution in 2020, and 13.6 million Americans experienced over 100 days of elevated ozone pollution. More needs to be done to curb health-threatening air pollution across the country.

Requiring power plants and other polluting facilities to install and effectively use modern pollution control technologies will clean up our air and save lives. If adopted, the rule would prevent approximately 1,000 premature deaths and avoid more than 2,000 hospital and emergency room visits, 1.3 million cases of asthma symptoms, and 470,000 school absence days in 2026. We can't pass up this opportunity to promote healthier communities across the country.

We urge EPA to adopt the strongest possible version of its proposed Good Neighbor Plan. Attached to this letter are 20,719 comments submitted by members of Environment America and U.S. PIRG supporting a strong rule that cleans our air and protects public health. We ask that these names be entered into the official record and considered as separate public comments.

Taking action to reduce smog pollution will save lives and ensure cleaner air across the country.

6. Mass Comment Campaign sponsoring organization unknown. Sample attached (web) EPA-HQ-OAR-2021-0668-0650

I strongly support the Environmental Protection Agency's proposed Cross State Air Pollution Rule, also known as the Good Neighbor rule, which will reduce harmful nitrogen oxide pollution that forms ozone from both power plants and other industrial facilities through the deployment of existing technologies. In doing so, this public health safeguard will also protect national parks and their sensitive ecosystems that are subjected to dangerous pollution from plants and facilities in upwind states.

We need solutions for pollution, and strong public health and ecosystem protections like the Good Neighbor rule to provide much needed relief from the burden of nitrogen oxides and ozone pollution.

Sensitive ecosystems, crops, trees, and plants can't escape the day-in, day-out and year-round exposure to ozone pollution. Neither can the people who seek to enjoy the outdoors or the park rangers who work and breathe outdoors. To help protect these people, special places and nature, I urge EPA to strengthen the Good Neighbor rule by:

- Ensuring that the rule not excuse state or polluter obligations under existing programs like the Regional Haze Rule that specifically aim to achieve year-round clear skies in national parks and wilderness areas. States like Utah and Wyoming are home to egregious polluters harming national park skies and over a dozen power plant units are already long overdue in complying with haze obligations. As EPA moves forward with the Good Neighbor rule, it should not delay or sacrifice necessary emissions reductions from other clean air programs.
- Making the pollution controls required as stringent as technologically feasible to maximize public health and environmental benefits.
- Expanding the industrial pollution sources covered under this rule further to include all power plants and other major industry sources in both upwind and downwind areas.
- Requiring sources to reduce emissions more quickly since this proposal gives industry more time than necessary to run existing pollution controls or install new ones. People and nature cannot wait any longer for the benefits of this cleanup:
    - If polluting sources have existing controls, they should be required to run them by the start of the next ozone season: May 1, 2023.
    - If polluting sources do not have existing controls, they should be required to install and optimally run them by May 1, 2024.

Our nations most treasured national parks and their ecosystems stand to benefit from this expanded Good Neighbor transport rule, which will bring cleaner air during the ozone season.

I applaud EPA for bringing it forward and strongly support its swift finalization and ask you to address the above measures to strengthen the proposal.

This, like numerous other issues (climate change, gun safety, immigration reform, prison reform, education reform, short-term lending regulation, healthcare reform, banking regulation, opioid regulation) remains a vexing problem primarily due to corporations' ability to curry favor with elected officials. The corrupting influence of money in our political system is undermining our democratic traditions and discouraging Americans from voting and/or running for office. This ominous development may well end our experiment in representative democracy unless we alter this decades-long trend. For the sake of the republic, we must amend the US Constitution to state that corporations are not people (and do not have constitutional rights) and money is not speech (and thus can be regulated by state and/or federal campaign finance laws). Short of accomplishing this, no other reform of significance will be achieved. The moneyed interests will turn any reform to their benefit, often at the expense of the nation as a whole.