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In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s Maddie Lipscomb

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This filing has been electronically filed and deemed to be signed by an authorized agent or
representative of the signer(s) and
Sierra Club

December 19, 2023

SENT VIA PUCN WEB PORTAL AND EMAIL

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East Williams Street
Carson City, NV 89701

Re: **Docket No. 23-08015**

Dear Ms. Osborne,

Please accept for filing the attached Direct Testimony of Rose Anderson on behalf of Sierra Club in the above-referenced docket.

Please let me know if you have any questions. Thank you.

Sincerely,

/s/ Maddie Lipscomb

Maddie Lipscomb
Legal Assistant
Sierra Club Environmental Law Program
(415) 977-5745

Enclosures
cc: Service List (via Email)

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fifth amendment to its 2021 Joint Integrated Resource Plan	))))))	Docket No. 23-08015

DIRECT TESTIMONY OF ROSE ANDERSON

ON BEHALF OF SIERRA CLUB

DECEMBER 19, 2023

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LIST OF ATTACHMENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q Please state your name and occupation.

A My name is Rose Anderson. I am a Principal Associate at Synapse Energy Economics. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

2. Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

3. Q Please summarize your work experience and educational background.

A At Synapse, I review planning assumptions and modeling in utility integrated resource plans.

Before joining Synapse, I performed economic analysis at the Oregon Public Utility Commission and at McCullough Research, an energy economics consulting firm.

A copy of my current resume is attached as Attachment RA-1.

4. Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

5. Q Have you testified previously before the Nevada Public Utilities Commission?

A No.

6. Q What is the purpose of your testimony in this proceeding?

A I evaluate the proposals of Nevada Power Company and Sierra Pacific Power Company (together, "NV Energy" or "the Company") to make significant changes to its plans for Valmy Generating Station ("Valmy") Units 1 and 2 and Tracy Generating Station ("Tracy") Units 4 and 5 as part of the Company's application for approval of the Fifth Amendment to its 2021 Joint Integrated Resource Plan ("IRP"). Specifically, I analyze the Company's proposal to convert Valmy Units 1 and 2 from coal to gas, install selective catalytic reduction ("SCR") technology to control nitrogen oxide ("NO_X") emissions, and to make capital investments to operate the repowered units until 2049. I also review the Company's proposal to install SCR at Tracy Units 4 and 5 and make capital investments to extend the operations of those units until 2049. I evaluate the support provided for these proposals in the Company's application and discuss alternatives that the Company did not consider. I recommend further analysis before moving forward with the Company's plans.

7. Q How is your testimony structured?

A In Section 3, I discuss the Company's proposal for the Valmy plant. In Section 4, I discuss the Company's proposal for Tracy Units 4 and 5.

8. Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the application for the Fifth Amendment to the 2021 IRP filed by the Company, as well as the Company's responses to discovery requests.

II. FINDINGS AND RECOMMENDATIONS

9. Q Please summarize your findings.

A My primary findings are:

1. The Company's application does not provide adequate support for its proposal to convert Valmy Units 1 and 2 to gas, install SCR, and run the units through 2049. In particular, the Company does not adequately analyze alternatives to the Valmy proposal that could meet identified needs in the Carlin Trend load pocket potentially at a lower cost, and with better adherence to the cost causation principle of ratemaking.

2. Based on the studies provided with this application, Valmy is needed for reliability in the Carlin Trend load pocket only before Greenlink West and Greenlink North are both in place, expected in 2028.[1] The Company is requesting to spend $82 million in ratepayer dollars on Valmy to provide support to Carlin Trend load pocket that likely is only needed for a few years.

3. It appears that the investment in Valmy to support Distribution Only Service ("DOS") customers in the Carlin Trend load pocket may not follow the cost-causation principle of ratemaking. The Company's Valmy proposal would incur costs in support of DOS customers that these customers would not pay for directly through their NV Energy tariff.[2] The Company's application did not address whether Valmy proposal costs would be included in DOS customers' Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") with NV Energy.[3]

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[1] Greenlink West is currently planned for service in May 2027 and Greenlink North is expected in December 2028. *See* NV Energy Response to Sierra Club Data Requests ("SC DR") 4-01, 4-02 (The Company's responses to Sierra Club data requests referenced in this testimony are provided in Attachment ["Attach."] RA-2).

[2] Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan [hereinafter "Application"], Vol. 1 at 251.

[3] Sierra Club has sent a data request to NV Energy regarding the contribution of Carlin Trend DOS customers to the cost of the Company's Valmy proposal via the OATT. The Company's response to that request is pending.

4. The Company's economic analysis for Tracy Units 4 and 5 is inadequate to support the Company's proposal to install SCR at the plant and extend the plant's operating life until 2049. The marginal expected benefits of the project do not outweigh the risks. In addition, the Company does not need to make a decision regarding SCR and continued operation at Tracy Units 4 and 5 at this time, since must-run generation is not required at these units. The NO_X emissions reductions necessary for compliance with the U.S. Environmental Protection Agency's ("EPA)" new Good Neighbor Plan can be facilitated through reduced generation at Tracy 4 and 5.

10. Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should find the portion of the Company's application that proposes conversion from coal to gas, SCR installation, and operation until 2049 at Valmy Units 1 and 2 to be inadequate. The Company has not provided enough support for this plan.

2. The Company should update its Valmy analysis to more comprehensively evaluate its options. These options should include reducing the operating timeframe, installing selective non-catalytic reduction ("SNCR") instead of SCR, and making investments in only one Valmy unit.

3. The Commission should find the portion of the Company's application that proposes SCR installation at Tracy Units 4 and 5 to be inadequate.

4. The Company should not proceed with SCR installation and capital expenses for continued operation of Tracy Units 4 and 5 at this time. There is not an urgent need to install SCR, since the Company should be able to manage the EPA's expected new NO_X emissions reduction requirements through reduced dispatch at Tracy Units 4 and 5. The economic analysis of SCR installation and operation of Tracy through 2049 showed a very small expected benefit, while the increased carbon emissions and associated risks of this approach would be substantial.

III. VALMY UNITS 1 AND 2

11. Q Please describe the current Valmy plant.

A Valmy is a 522 megawatt ("MW") power plant located west of Battle Mountain, Nevada, with two coal-fired steam units.[4] The plant is co-owned by NV Energy and Idaho Power. NV Energy owns a 50 percent share of the plant's generating capacity, i.e. 261 MW.[5] The units were built in 1981 and 1985 and are 42 and 38 years old, respectively.[6]

12. Q Prior to the current application, what was the Company's plan for retirement of Valmy?

A The Company's pre-application planned retirement date for Valmy Units 1 and 2 is in 2025.[7] The Title V air quality permit for Valmy Units 1 and 2 imposes a federally enforceable retirement date of December 31, 2028.[8]

13. Q Why has NV Energy filed this update and proposed modifications for Valmy Units 1 and 2?

A In Docket No. 16-07001, the Commission directed the Company to update its 2018 Valmy retirement study, called the Life Span Analysis Process ("LSAP").

[4] Application, Vol. 1 at 63.
[5] *Id.* at 63, 64 n.24.
[6] *Id.* at 64 (Table GEN-1).
[7] *Id.*
[8] *Id.* at 67.

14. Q What is NV Energy requesting in this docket related to Valmy Units 1 and 2?

A NV Energy is requesting approval of its proposal to spend $20.4 million to convert Valmy Units 1 and 2 from coal to gas and spend $30 million to install SCR technology at both units. It is also asking to spend $32.25 million to extend the operating lives of those units until 2049.[9] Specifically, the Company proposes to convert Unit 1 from coal to gas by December 31, 2025, and to convert Unit 2 from coal to gas by June 1, 2026.[10] The total cost of the project, shared between Idaho Power and NV Energy, would be $165 million. NV Energy's 50 percent share would be $82.6 million.[11]

15. Q What materials does the Company provide in support of its proposal regarding the Valmy plant?

NV Energy provided the following materials in this application in support of its Valmy proposal:

1. A narrative explanation of the proposal in Volume 1,
2. Testimony explaining the proposal in Volume 2,
3. An updated 2023 transmission system reliability Study (Valmy Must Run Requirement Study),
4. A study on resource economics of certain options for Valmy (Valmy LSAP 2023 Update),

[9] Application, Vol. 1 at 90 (Table GEN-4). Table GEN-4 was redacted in the original application, but the Company later made Table GEN-4 public on December 4, 2023.
[10] *Id.* at 88.
[11] *Id.* at 89.

5. An earlier 2018 LSAP analysis for Valmy, and

6. A 2023 Key Decision Report explaining the Company's Valmy proposal.

In the supporting materials, NV Energy evaluates many scenarios of transmission system reliability, as well as a few scenarios on the economics of replacing or repowering Valmy. But none of these studies provide sufficient support for the Company's proposal. For example, the 2023 Valmy Must Run Study finds that, "[w]ith adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy." [12] Thus, the study does not provide adequate support for the Company's plans to run Valmy through 2049. I will describe and assess these materials in the sections below in more detail.

16. Q Please describe the support for the Valmy proposal that NV Energy provides in the narrative in Volume 1 of its application.

A In the narrative in Volume 1 of the application, NV Energy relies heavily on the studies filed with the application (items 3 through 6 above) to support its Valmy proposal. In addition, the narrative provides general support for the Valmy proposal, including:

- A "need for voltage support and available around-the-clock generation in the Carlin Trend load pocket," and for "operating or quick-start generation" located at or near Valmy until Greenlink West is in service, citing the 2023 Must Run Study provided with the application;[13]

[12] Application, Vol. 4 at 19.
[13] Application, Vol. 1 at 12, 32.

- Cancellation of the Hot Pot and Iron Point projects previously intended to help replace Valmy;[14]

- The Good Neighbor Plan's strict limits on the amount of NO_X that can be emitted at Valmy during the ozone season from May through September. NV Energy states that these restrictions will phase in during 2026 and 2027, with a 50 percent reduction of the 2021 emissions rate for each unit required in 2026 and a "fully controlled emission rate of 0.05 lb/MMBtu, commensurate with SCR retrofits" beginning in 2027;[15]

- Recent issues with coal supply procurement and ongoing coal fuel supply risk;

- The Company's carbon reduction goals;[16] and

- Economic analysis of portfolios that include either Valmy coal to gas conversion or replacement of Valmy with two combustion turbines.[17]

17. Q Does NV Energy provide adequate support for the Company's Valmy proposal in the narrative?

A No. The narrative summarizes other studies provided with the Company's filing (items 3 through 6 listed above) and relies on these studies to support the Company's assertion that the only viable options for Valmy are (1) the Company's proposal to repower Valmy, install SCR, and run Valmy through 2049; or (2) an option to replace Valmy with two

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[14] *Id.* at 32.
[15] *Id.* at 69.
[16] *Id.* at 34.
[17] *Id.* at 149–150.

combustion turbines by summer 2027. The economic analysis in the narrative begins with these restrictive assumptions. [18] However, the Valmy studies that the narrative references do not completely support this interpretation; they could also be consistent with a variety of other plans not considered in the narrative, as I will explain.

In the narrative, the Company asserts that under Good Neighbor Plan requirements, NO_X-reducing equipment will be required at Valmy to maintain must-run status during the ozone season, but it does not provide analysis to support this claim or assess whether SNCR would be adequate. According to the Nevada Regional Haze State Implementation Plan ("SIP"), the cost of SNCR is one-tenth the cost of SCR for Valmy.[19]

The Company states elsewhere in the narrative that it is "reasonably anticipated" that coal-fired must-run operation at Valmy could likely be sustained through the 2026 ozone season without SCR installation.[20] In the 2027 ozone season however, NO_X restrictions would no longer allow must-run coal operation at Valmy.[21] Thus, it appears possible that the Company's schedule for gas conversion and SCR at Valmy could be pushed back one year from completion in May 2026 to completion in May 2027 to facilitate further study of alternatives.[22]

The Valmy Must Run Study indicates that the transmission system can withstand the retirement of Valmy, but not until Greenlink West is completed or additional generation is added to the system.[23] If the Company can bring additional transmission and generation online as expected, then the usefulness of SCR and capital projects for

[18] *Id.* at 175–183.
[19] Nev. Div. of Env't Prot. and Nev. Dep't of Conservation & Nat. Res., *Regional Haze SIP For the Second Planning Period* at 5-12 (Aug. 2022), *available at* https://ndep.nv.gov/uploads/air-plan_mod-docs/All_SIP_Chapters.pdf, excerpt attached as Attach. RA-3.
[20] Application, Vol. 1 at 70.
[21] *Id.*
[22] *See id.* at 92.
[23] Application, Vol. 4 at 19.

continued operation at Valmy could be greatly reduced during the three year period from 2026 through 2028.

Finally, the economic analysis provided in the narrative appears to greatly undervalue the potential to reduce portfolio costs by selling renewable energy in market transactions. The Company apparently assumes that any renewable energy not needed for retail customers is curtailed, instead of being sold at market. The Company refers to this energy as “dump energy.”[24] In the later years of one portfolio, “dump generation” reaches almost 16,000 GWh a year and accounts for 32 percent of the total amount of renewable generation.[25] This unrealistically reduces the ranking of renewable energy portfolios in the application. In actual operations, the Company should sell this energy to the market to reduce costs for customers.

18. Q Please describe the support for the Valmy proposal that NV Energy provided in testimony in Volume 2 of the application.

A In the prefiled testimony in Volume 2 of the application, NV Energy provides general reasoning in support of the Valmy proposal but does not provide new analysis. In the testimony, the Company points to the other studies included with the application for support.

19. Q Please assess the support for the Valmy proposal in the testimony of Ryan Atkins.

A Ryan Atkins refers to the Must Run Study to support claims that there are “two feasible options support the retirement of coal generation at Valmy and to support the continuing

[24] Application, Vol. 1 at 163.
[25] Application, Vol. 5 at 13–14.

need for a firm dispatchable resource: the refueling of Valmy to burn natural gas or the construction of new natural gas-fired peaking units at the Valmy site."[26]

The Must Run Study does find that generation at Valmy is required "until Greenlink West is complete or additional generation is added to Sierra's system."[27] However, this conclusion does not support the Company's proposal for SCR or capital projects for continued operation at Valmy. In fact, the Must Run Study concludes, "[w]ith adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy."[28]

20. Q Please assess the support for the Valmy proposal in the testimony of Matthew Johns.

A Matthew Johns generally describes the impacts that the Regional Haze Rule, Good Neighbor Plan, and Clean Air Act regulations may have on the Company's coal and gas generation. Johns does not provide any concrete analysis showing that SCR or gas conversion at Valmy is required to support compliance with these regulations.[29]

21. Q Please assess the support for the Valmy proposal in the testimony of John Lescenski.

A John Lescenski describes the Company's updated 2023 LSAP and explains that it finds conversion to gas and operation through 2049 to be the Company's preferred plan. However, as I will explain below, the 2023 LSAP considers only four resource options and should not be considered a rigorous study of the Company's options.

[26] Application, Vol. 2 at 11–12.
[27] Application, Vol. 4 at 19.
[28] *Id.*
[29] Application, Vol. 2 at 55–56.

22. Q Please assess the support for the Valmy proposal in the testimony of Charles Pottey.

A Charles Pottey relies on the 2023 Must Run Study to support "the need for the existing Valmy area generation must-run procedure" until Greenlink West is completed, when "the must-run procedure may be able to be suspended subject to load growth and planned outages."[30] While this may be an accurate description of the Must Run Study, neither Pottey's testimony nor the Must Run Study actually demonstrate a need to limit the Company's options to either Valmy repowering with SCR or replacement of Valmy with two combustion turbines. Nor do they support running Valmy through 2049.

23. Q Please assess the support for the Valmy proposal in the testimony of Kimberly Williams.

A Kimberly Williams describes the 2023 Must Run Study as requiring "generation at or near Valmy that must be online or able to start quickly in the event of a transmission outage, and able to continue to generate until the outage is corrected."[31] Williams notes that even after the in-service date of Greenlink West, transmission reliability issues could continue to create the need for must-run generation at Valmy to avoid potential load shedding.[32] However, Williams does not mention that, in the Must Run Study, the addition of Greenlink North resolves the identified reliability violations, even in the absence of Valmy and Newmont Mining Company's TS Power Plant ("TSPP") as I will discuss further below.

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[30] *Id.* at 143:20-21, 144:13-14.
[31] *Id.* at 173:17-19.
[32] *Id.* at 173–174.

24. Q Please describe the 2023 Valmy Must Run Study and its findings.

The 2023 Must Run Study is an update to the transmission studies in the 2018 Valmy LSAP. In the updated study, the Company evaluates transmission system reliability under peak summer load conditions in 2025, before the Greenlink West transmission project is in service, assuming that Valmy and Newmont TSPP are both offline. The Company includes the addition of approximately 537 MW of forecasted high voltage distribution ("HVD") customer load, representing load forecasts from currently contracted customers.[33]

This study represents the system in a state of peak stress. The Company models transmission outages during this stressed state to test transmission system reliability. The modeling includes P1 scenarios, which usually involve one major transmission system outage (N-1), and also P6 scenarios, which usually involve two transmission line outages (N-1-1).

In the study, NV Energy looks at four cases in 2025.[34] The Company's modeling identifies some reliability issues, along with the solutions necessary to resolve them.[35] The solutions often require additional generation to be added near Valmy or Tracy. The Company concludes that in 2025, "[t]o fully support the contracted load for new customers, generation at Valmy will need to be retained or replaced with 24 hour dispatchable generation[]."[36]

[33] Application, Vol. 4 at 6.
[34] *Id.* at 11–12.
[35] *Id.* at 18.
[36] *Id.* at 14.

The Company considers an additional 2027 scenario, after Greenlink West is in service.[37] The Company finds that after Greenlink West is in service, P1 scenarios either result in no voltage violations, or they result in violations that can be managed with the installation of new capacitor banks.[38] In a P6 scenario where the loss of Greenlink West is followed by the loss of a second major line, "[l]oad shedding may be required."[39] However, it appears that this potential load shedding under the loss of two separate transmission lines may be in compliance with North American Electric Reliability Corporation ("NERC") standards, since it is associated with a NERC Under Voltage Load Shedding ("UVLS") operation.[40]

Importantly, the Company finds that all transmission system issues identified in Appendix C are resolved with the addition of Greenlink North.[41]

25. Q Does the 2023 Valmy Must Run Study provide adequate support for the Company's Valmy proposal?

A No. In this study, NV Energy finds that, under peak conditions, 24-hour dispatchable generation near Valmy is necessary for transmission system reliability before Greenlink West is in place.[42] However, the addition of Greenlink West resolves many of the identified reliability issues, and the further addition of Greenlink North resolves the

[37] *Id.* at 12.
[38] *Id.* at 15.
[39] Application, Vol. 4 at 15, 110.
[40] *See* NERC, PRC-010-1 – Undervoltage Load Shedding, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-010-1.pdf (last visited Dec. 18, 2023), attached as Attach. RA-4.
[41] Application, Vol. 4 at 16 ("Following the completion of Greenlink North, the above P6 limitation would no longer be a valid concern.").
[42] *Id.* at 14.

remaining identified issue. Greenlink West is currently planned for service in May 2027 and Greenlink North is expected in December 2028.[43]

The Must Run Study provides insight into the grid in 2025 and 2027, but it does not support the Company's plans to run Valmy through 2049. As soon as Greenlink North is in service in 2028, the study indicates no further transmission system issues resulting from Valmy retirement.[44]

Further, the Valmy Must Run Study looks only at peak conditions. It does not assess whether 24-hour dispatchable generation at Valmy is necessary under normal load conditions. In the study, the Company concludes that Valmy should not be retired until Greenlink West is complete or additional generation is added to Sierra's system,[45] but the Must Run Study does not actually mention whether or when must-run status should be required at Valmy. Thus, while the study may indirectly provide support for placing one Valmy unit into must-run status during peak conditions to ensure that one unit is running at all times, it does not provide adequate support for placing Valmy units in must-run status during off-peak times of year.

The Must Run Study does not include consideration of whether SCR at Valmy would be required after the Good Neighbor Plan begins to require significant NO_X emissions reductions in 2026.[46] The study therefore cannot be used to support the Company's plans to install SCR at Valmy without further analysis, which the Company has not provided.

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[43] NV Energy Response to SC DRs 4-01, 4-02 (Attach. RA-2).

[44] *See* Application, Vol. 4 at 16.

[45] *Id.* at 19.

[46] *See* Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 33,654, 33,654–36,666, 36,754–36,844 (June 5, 2023), *available at* https://www.federalregister.gov/documents/2023/06/05/2023-05744/federal-good-neighbor-

26. Q Please describe the support for the Valmy proposal that NV Energy provided in the 2023 Valmy LSAP Update.

A The 2023 Valmy LSAP Update looks at the cost of four different Valmy scenarios, without assessing transmission system reliability. Two scenarios assess the cost of a portfolio that converts the existing Valmy units to gas, with different allocations between NV Energy and Idaho Power.[47] A third scenario assesses the cost of replacing Valmy with new simple cycle combustion turbines.[48] The fourth scenario assesses the cost of replacing Valmy with solar plus battery storage.[49]

The LSAP update finds that keeping Valmy online and converting the plant to gas with SCR is expected to be less expensive than either of the two other replacement scenarios considered. In comparison, the scenario that retires Valmy and replaces it with combustion turbines has similar costs to the repowering scenario.[50] The solar plus storage scenario appears significantly more expensive than the other options, however it is not clear whether the Company included a realistic estimate of the value of renewable energy market sales, or unrealistically assumed that any renewable energy generation in excess of retail load would be curtailed.[51]

plan-for-the-2015-ozone-national-ambient-air-quality-standards, excerpt attached as Attach. RA-5.

[47] Application, Vol. 3 at 27.
[48] *Id.*
[49] *Id.* at 28.
[50] *Id.* at 30.
[51] *Id.*

27. Q Does the 2023 Valmy LSAP provide adequate support for the Company's Valmy plans?

A No. NV Energy evaluated only two alternative scenarios to the Valmy gas conversion, and these do not represent the full range of alternatives to the Company's plan. This study does not optimize a resource portfolio to find the lowest-cost alternative to continued operation of, and investment in, Valmy.

The study also does not assess whether SCR installation would be required to meet Good Neighbor Plan requirements.

If the Company excluded market sales revenues from the analysis, it would create a substantial bias against portfolios with renewable energy, resulting in excessively high costs for the solar plus storage scenario.

28. Q Please describe the 2023 Key Decision Report.

A In the Key Decision Report ("KDR"), NV Energy assesses four Valmy operational scenarios for transmission system reliability.[52] Based on these assessments, the KDR discusses the Company's decision to establish must-run conditions for Valmy units (a) when Newmont TSPP is online and (b) when Newmont TSPP is offline. When Newmont TSPP is online, the report recommends placing either Valmy Unit 1 or Valmy Unit 2 in Reliability Must Run ("RMR") status.[53] When Newmont TSPP is offline, the report recommends placing both units in RMR status.[54]

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[52] Application, Vol. 4 at 227–228.
[53] *Id.* at 221.
[54] *Id.*

29. Q Does the KDR provide adequate support for the Company's proposal?

A No. The KDR looks at the system before Greenlink West is in service. Therefore, it would appear that the KDR's findings regarding the need for must-run status at Valmy cannot be extrapolated beyond the in-service date of Greenlink West.

In addition, the KDR reports that a plan without Valmy 1 would be NERC-compliant, even though it would have "a high level" of customer risk.[55] The fact that the Company did not further evaluate a plan without Valmy 1, despite the savings that could be achieved by avoiding investment in Valmy 1, highlights that NV Energy is planning to a higher-than-necessary standard for Carlin Trend customers.

30. Q Please describe the 2018 Valmy LSAP in Volume 4 of the application.

A The 2018 LSAP was created by NV Energy to evaluate the potential to retire Valmy in 2025 and maintain system reliability. In the 2018 LSAP, NV Energy identifies the additional resources needed to support a 2025 Valmy retirement. In the study, the Company looks at ten main scenarios, including scenarios without Valmy and Newmont Mining Company's TSPP, high system import scenarios, and a scenario with 600+ MW of load growth in the Tracy area.[56]

In the 2018 LSAP, NV Energy evaluated these scenarios and found that the system impacts of 2025 Valmy retirement could be mitigated in each scenario with the appropriate combination of reactive support, new transmission, and new solar PV and battery energy storage.[57] In the most challenging scenario, Case 10, NV Energy assumed

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[55] *Id.* at 227.
[56] *Id.* at 136–137.
[57] *Id.* at 137–148.

628 MW of load growth in the Tracy area, with Valmy and Newmont TSPP offline under peak summer conditions.[58] NV Energy finds that a new 345 kV line and the installation of a static VAR compensator ("SVC") at Valmy would resolve reliability issues.[59]

The study concludes that "[w]ith adequate reactive support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy."[60]

31. Q Does the 2018 Valmy LSAP support the Company's Valmy proposal?

A The 2018 LSAP does not support the Company's proposal for gas conversion, SCR installation, and continued generation at Valmy through 2049. Quite the opposite, the 2018 LSAP finds that 2025 Valmy retirement can be supported by the right combination of investments in the transmission grid and planned new sources of generation.

Given that the 2018 LSAP has been available to the Company for several years, it is not clear why the Company has implemented "[a]lmost none" of the recommended investments in, or electrically close to, the Carlin Trend load pocket region of the transmission grid.[61]

[58] Application, Vol. 4 at 146.
[59] *Id.* at 147.
[60] *Id.* at 160.
[61] *Id.* at 225.

32. Q What is your conclusion after reviewing the materials provided in support of the Company's plans for Valmy Units 1 and 2?

A While the materials summarized above provide useful information about a few potential Valmy retirement scenarios, they do not provide adequate support for the Company's proposal to spend $82.6 million on Valmy gas conversion, SCR, and continued operation through 2049.[62] In fact, the application materials show that with adequate new resources, the transmission system can be operated reliably without coal or gas generation at Valmy.

33. Q Besides the lack of support for the Company's Valmy proposal, what other concerns do you have about this approach to Valmy Units 1 and 2?

I am concerned that spending $82.6 million on gas conversion, SCR installation, and continued operations at Valmy Units 1 and 2 will make it more difficult for the Company to retire the units, and risks creating a stranded asset. The Company has not done sufficient analysis to show that the Company's proposal is a better option for retail customers than retiring Valmy once the system can be made reliable through other new transmission and generation investments. Locking ratepayers into more costs now will make accelerated depreciation and retirement at Valmy more expensive in the future. Additionally, adding to the Company's gas generation portfolio will expose customers to the increased fuel price risk associated with global markets for natural gas.

Another concern is that the Company is planning to support reliability for its DOS customers in the Carlin Trend load pocket by incurring expenses at the Valmy plant for which DOS customers will not pay a share proportionate to their contribution to cost causation. NV Energy is planning to a reliability standard that exceeds NERC requirements for Carlin Trend customers, citing safety concerns at underground mines.[63]

[62] *See* Application, Vol. 1 at 89.
[63] Application, Vol. 4 at 222, 227.

Approximately 71 percent of the energy currently delivered to Carlin Trend load pocket is for DOS customers who do not pay for expenses associated with electric generators in their NV Energy DOS rate.[64] The extent to which these customers may pay for some costs of upgrading Valmy through their FERC OATT for transmission service through NV Energy is unclear, but seems unlikely to fully reflect their contribution to cost causation at Valmy.[65]

34. Q Is there another approach to Carlin Trend reliability that you think would be fairer to retail ratepayers?

A The Company should carefully consider whether major investments in Valmy are necessary at this time, when a transmission solution to reliability issues at the Carlin Trend load pocket is only a few years away. The 2023 Valmy Must Run Study found that with Greenlink West and Greenlink North both in service, and with a few transmission system upgrades, the P1 events identified would be resolved and the P6 event identified would no longer be a valid concern.[66] Greenlink West is expected to be in service in May 2027, and Greenlink North in December 2028.[67]

To the extent that Carlin Trend customers have safety and reliability needs above the Company's normal standards for reliable transmission service, these customers should invest in backup generation or storage.

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[64] NV Energy's Response to SC DR 3-24 (Attach. RA-2).
[65] Sierra Club has sent a data request to NV Energy regarding any contribution of Carlin Trend DOS customers to the cost of the Company's Valmy proposal via the OATT. The Company's response to that request is pending.
[66] *See* Application, Vol. 4 at 15–16, 110.
[67] NV Energy Response to SC DRs 4-01, 4-02 (Attach. RA-2).

35. Q Do you have suggestions for alternatives to the Company's Valmy proposal?

A The Company has a challenging task in ensuring reliability at the Carlin Trend load pocket during 2026 and 2027 before Greenlink West is in place and as the Good Neighbor Plan's strict NO_X reduction requirements go into effect. However, after Greenlink North is in place, the 2023 Must Run Study indicates there will no longer be a need for generation at Valmy to support NERC standards in the Carlin Trend load pocket.[68]

The Company's application has not shown any need to operate Valmy through 2049. Instead of operating Valmy through 2049, it may be best to seek options to operate Valmy only through 2027 or 2028, and avoid making investments in gas conversion, continuing operations, and SCR at Valmy. Capital expenditures for continued operation through 2049 are a substantial part of the Company's proposal at $32.25 million,[69] and the application has established no need for generation through 2049.

It is NV Energy's responsibility to adequately evaluate resource plans, and to identify a plan for Valmy that meets system reliability needs while both reducing costs and allocating costs fairly. While the Company needs to maintain a NERC-compliant transmission system, it is questionable whether the Company should go above and beyond NERC requirements to provide even greater reliability to Carlin Trend customers. There may be measures the Company can take, for a limited time until Greenlink North is in place, to ensure adequate reliability in the Carlin Trend load pocket without making major investments in the 40-year-old Valmy plant. NV Energy should perform further analysis to evaluate this possibility.

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[68] Application, Vol. 4 at 16.
[69] Application, Vol. 1 at 90 (Table GEN-4). Table GEN-4 was redacted in the original application, but the Company later made Table GEN-4 public on December 4, 2023.

During the challenging years before Greenlink North is in place, the Company should create savings for customers and maintain transmission system reliability through alternatives to gas conversion, continued operations, and SCR at Valmy. Some alternatives that NV Energy should consider include:

- Perform an update to the 2023 Valmy Must Run Study to assess whether the Valmy units could be placed on standby during off-peak months in 2026–2028. This could help reduce Valmy's NO_X emissions during the Ozone Season (May through September) enough to comply with the Good Neighbor Plan without SCR installation. The 2023 Must Run Study did not assess off-peak months.

- Study transmission system reliability after Greenlink West is in service, with the storage output at Sierra Solar Battery Energy Storage System held back intentionally to provide support for reliability needs 24 hours a day. This could provide several hours of lead time for the Company to implement load management or other changes to maintain transmission system reliability in the absence of Valmy, even before Greenlink North is in place.

- Retire one Valmy unit in 2025 or else place a unit on standby and avoid the cost of gas conversion and SCR at one Valmy unit.

- To maintain control of two sources of generation near Carlin Trend, negotiate a deal with Newmont for NV Energy to operate TSPP until Greenlink North is in place.[70]

- Assess the installation of SNCR instead of SCR to meet the requirements of the Good Neighbor Plan at a lower cost.

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[70] NV Energy asserts that "[t]o mitigate reliability issues in the area, two sources of generation need to be under NV Energy control." *See* Application, Vol. 4 at 223.

- Enroll Carlin Trend customers in a demand response program that allows customers to receive substantial compensation for curtailment before Greenlink North is in place.

- Allow Carlin Trend DOS customers to install their own backup generation or local battery storage resources (of sufficient size and duration) to safely shut down mining operations in the event of load shedding before Greenlink North is in place, rather than the Company planning to an unnecessarily high standard of reliability for Carlin Trend DOS customers.

36. Q What is your recommendation regarding the Company's application with respect to Valmy?

A First, I recommend that the Commission find the portion of the Company's application that proposes gas conversion at Valmy, SCR installation, and operation of the plant until 2049 to be inadequate. The Company has not shown that this is the best option for customers.

Second, the Company should perform more analysis on Valmy alternatives. The Company has reported that the Valmy plant can likely satisfy a must-run requirement in 2026 without gas conversion or NO_X controls, while remaining within the Good Neighbor Plan's NO_X limitations.[71] This should allow enough time for the Company to perform more analysis before it makes a decision.

First, the Company should provide the Commission with a report showing the potential to avoid a portion of the capital costs associated with preparing the Valmy plant for continued operation through 2049, since Valmy will become less important for system reliability after Greenlink North is in place (expected in December 2028.) These capital

[71] Application, Vol. 1 at 70.

projects for continued operation comprise 40 percent of the Company's total proposed Valmy investment, so this step could reduce costs significantly.

Second, the Company should provide the Commission with a report on the potential to install SNCR instead of SCR at one or both Valmy units to minimize costs for customers while meeting Good Neighbor Plan and NERC reliability requirements.

Third, the Company should report on the potential for demand response, customer-sited backup generation or storage, negotiation with Newmont for operation of TSPP until new transmission is in place, and other options to avoid costs associated with long-term operation of the Valmy plant.

IV. TRACY UNITS 4 AND 5

37. Q Please describe Tracy Generating Station.

A Tracy Generating Station is a 773 MW gas-fired power plant located east of Reno, Nevada.[72] Tracy Units 4 and 5 are operated together as a gas-fired combined-cycle generator that provides 104 MW of capacity.[73] NV Energy owns 100 percent of Tracy Units 4 and 5. The units were built in 1996.[74]

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[72] *Id.* at 63.
[73] *Id.* at 64 (Table GEN-1); NV Energy Response to SC DR 5-06 (Attach. RA-2).
[74] Application, Vol. 1 at 64 (Table GEN-1).

38. Q Prior to this application, what was the planned retirement date for Tracy?

A NV Energy's pre-application planned retirement date for Tracy Units 4 and 5 is 2031.[75] The Title V air quality permit for Tracy Units 4 and 5 imposes a federally enforceable retirement date of December 31, 2031.[76]

39. Q Why has NV Energy filed this update and proposed modifications for Tracy Units 4 and 5?

A The Tracy LSAP states that the nearing retirement date and the Good Neighbor Plan's NO_X emissions limitations caused the need for an evaluation of the operating life for Tracy Units 4 and 5.[77]

40. Q What is NV Energy requesting in this docket related to Tracy Units 4 and 5?

A NV Energy is requesting to install SCR at Tracy Units 4 and 5 and to extend operations until 2049. This is 18 years beyond the previously planned 2031 retirement date. The expected cost of SCR installation at Tracy Units 4 and 5 is $12 million, and the expected cost of capital expenditures for continuing operation through 2049 is $41.5 million.[78] The Company's analysis predicts that this proposal will save customers approximately $18 million over 28 years, as compared to retiring Tracy Units 4 and 5 in December, 2031.[79]

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[75] *Id.*
[76] *Id.* at 67.
[77] *See* Application, Vol. 3 at 106–109.
[78] *See* Attachment to NV Energy Response to Staff DR 01, attached as Attach. RA-6.
[79] Application, Vol. 3 at 112–113.

41. Q Please describe the support for the Tracy Units 4 and 5 proposal provided in the Company's application.

A The application includes a narrative discussion in Volume 1, Testimony in Volume 2, and the Tracy LSAP in Volume 3.

42. Q Please describe the support for the Tracy Units 4 and 5 proposal provided in the Narrative.

A The narrative states that SCR and continued operation at Tracy Units 4 and 5 is marginally less expensive than retirement in 2031, citing the Tracy LSAP.[80] The narrative requests approval of the Company's proposal for Tracy Units 4 and 5 at this time.

43. Q Please describe the support for the Tracy proposal provided in the Tracy LSAP.

A The Tracy LSAP considers only two scenarios: retirement of Tracy Units 4 and 5 in 2031 or continued operation through 2049 with SCR installation. The study finds that installing SCR and running the units through 2049 is marginally less expensive by about $18 million over 28 years.[81]

44. Q Do you agree that approval of the Company's proposal for Tracy Units 4 and 5 should be approved now?

A No. The Commission should not approve the Company's proposal for Tracy Units 4 and 5 at this time. The economics of Tracy Units 4 and 5 have been shown to be marginal,

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[80] Application, Vol. 1 at 184.
[81] Application, Vol. 3 at 113.

and there appears to be ample time for the Company to act carefully. The Company proposes for SCR construction to begin in October of 2027 and take only three months.[82] Retirement of Tracy Units 4 and 5 is not legally required until December 31, 2031.[83]

45. Q What are the risks of installing SCR at Tracy Units 4 and 5 now?

A Installing SCR at Tracy Units 4 and 5 at this time is unnecessary and risky because of the marginal economics of keeping the units online. If SCR is installed as planned, and then additional unexpected expenses occur or gas prices increase more than expected, it will be too late to avoid the cost of SCR installation and save that money for customers by retiring Tracy Units 4 and 5 in 2031 as planned. Should the economics of the units tilt strongly in favor of retirement after the installation of SCR, the cost of the SCR would become a stranded asset potentially borne by ratepayers.

Additional expenses could occur because of the age of the plant, or because of future carbon regulation. Although the EPA's proposed Clean Air Act Section 111(d) carbon rules likely will not apply to Tracy as a generator under 300 MW, the risk of further carbon regulation in the future is high. Customers will be more likely to benefit from investments in new, clean generation instead of investment in an older combined cycle generator that is "nearing the end of its design life."[84]

[82] Application, Vol. 1 at 94 (Table GEN-8).
[83] *Id.* at 67.
[84] Application, Vol. 3 at 109.

46. Q What alternatives for Tracy Units 4 and 5 should NV Energy have considered in this amendment?

A NV Energy has the option to meet Good Neighbor Plan requirements at Tracy Units 4 and 5 through reduced dispatch or installation of much less expensive SNCR technology. Either approach would avoid a significant capital outlay of $12 million for SCR.[85]

NV Energy should not perform capital upgrades for continued operation at Tracy Units 4 and 5 at this time. With a 2031 planned retirement date, there is plenty of time to carefully consider this decision and observe whether the units' economics improve or decline.

Regarding the Regional Haze Program, the Company has the option of including a plan for reduced dispatch and/or SNCR installation at Tracy Units 4 and 5 in an amended Nevada Regional Haze SIP. The Company could also retire the Tracy units in 2031 as currently required.

47. Q What do you recommend regarding Tracy Units 4 and 5?

A The Commission should find the portion of the Company's application that proposes SCR installation at Tracy Units 4 and 5 and continued operation of those units until 2049 to be inadequate. The marginal benefits shown do not outweigh the risks of a significant investment in Tracy Units 4 and 5.

NV Energy has not demonstrated that it is in the best interest of customers to install SCR at Tracy Units 4 and 5 at this time or to extend the units' operating lives to 2049. The units are 27 years old already.[86] If it becomes apparent before 2031 that operating the units until 2049 would result in unexpected costs, that could tilt the economic analysis in

[85] *See* Attachment to NV Energy Response to Staff Data Request 01 (Attach. RA-6).
[86] Application, Vol. 3 at 109.

favor of a 2031 retirement. The Tracy units could require unexpected repairs, or a future carbon policy could impact the units' economics.

48. Q Does this conclude your testimony?

A Yes.

AFFIRMATION

STATE OF NEVADA)
: ss.
CARSON CITY)

Pursuant to the requirements of NRS 53.045(1) and NAC 703.710, I, Rose Anderson, swear that I am the person identified in the attached Direct Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

I declare under penalty of perjury under the law of the State of Nevada that the foregoing is true and correct.

Executed on: December 19, 2023 *_/s/ Rose Anderson_*

ATTACHMENT RA-1

Rose Anderson Resume

Rose Anderson, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-812-1573
randerson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, September 2023 – Present.

- Provide research and analysis on integrated resource planning.
- Assess the economics of generation resources compared to alternatives and market purchases.
- Write expert testimony on power plant economics and integrated resource planning.

Oregon Public Utility Commission, Salem, OR. *Senior Economist,* October 2019 – September 2023; *Senior Renewables Analyst,* May 2018 – October 2019, *Utility Analyst,* September 2016 – May 2018.

Senior Economist:

- Prepared written comments and testimony.
- Lead OPUC staff review of utility Integrated Resource Plans (IRP) and resource acquisition proceedings.
- Evaluated utility production cost and capacity expansion modeling.
- Mentored OPUC staff regarding resource economics and best practices for review of utility filings.

Senior Renewables Analyst:

- Prepared written comments and testimony.
- Lead staff review and critical analysis of utility IRPs.
- Analyzed IRP modeling assumptions.
- Developed Excel model of rate impacts.

Utility Analyst:

- Reviewed and analyzed utility rate filings and workpapers for compliance.
- Prepared testimony in rate case and power cost filings.
- Reviewed utility production cost modeling inputs/outputs/workpapers.
- Lead and participated in review of power cost filings.

McCullough Research, Portland, OR. *Research Associate*, June 2013 – January 2015.

- Acquired, cleaned, and analyzed energy data sets in MS SQL and Excel.
- Researched nuclear energy and presented findings in a report.
- Analyzed bidding data from the MISO market.

EDUCATION

University of California, Davis. Davis, California
Master of Science in Agricultural and Resource Economics, 2016

University of Puget Sound, Tacoma, Washington
Bachelor of Arts in International Political Economy, 2007

PUBLICATIONS AND PRESENTATIONS

Oregon Public Utility Commission (Docket No. LC 79): Final Comments regarding NW Natural's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 30, 2023.

Oregon Public Utility Commission (Docket No. LC 79): Opening Comments regarding NW Natural's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 30, 2022.

Oregon Public Utility Commission (Docket No. LC 77): Final Comments and Staff Report regarding PacifiCorp's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. February 11, 2022.

Oregon Public Utility Commission (Docket No. LC 77): Opening Comments regarding PacifiCorp's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 3, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Staff Report regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. October 6, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. August 19, 2021.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. August 18, 2021.

Oregon Public Utility Commission (Docket No. LC 71): Staff Report regarding The Third Update to NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. July 12, 2021.

Oregon Public Utility Commission (Docket No. LC 71): Opening Comments regarding The Third Update to NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. May 14, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. December 8, 2020.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. December 4, 2020.

Oregon Public Utility Commission (Docket No. UM 2005): Presentation of Rose Anderson on Integrated Resource Planning. On behalf of Oregon Public Utility Commission Staff. June 11, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. April 29, 2021.

Oregon Public Utility Commission (Docket No. LC 70): Report regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. April 17, 2020.

Oregon Public Utility Commission (Docket No. UM 2059): Report regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. April 1, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 6, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 4, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. January 10, 2020

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. October 25, 2019.

Oregon Public Utility Commission (Docket No. LC 71): Final Comments regarding NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 31, 2018.

Oregon Public Utility Commission (Docket No. LC 70): Staff Report for the December 28, 2018 Special Public Meeting. On behalf of Oregon Public Utility Commission Staff. December 13, 2018.

Oregon Public Utility Commission (Docket No. LC 71): Opening Comments regarding NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. October 15, 2018.

Oregon Public Utility Commission (Docket No. UE 230): Report of Rose Anderson on PGE's schedule 145 update request. On behalf of Oregon Public Utility Commission Staff. December 14, 2017.

Oregon Public Utility Commission (Docket No. UE 315): Report of Rose Anderson regarding PacifiCorp's request for revised rates. On behalf of Oregon Public Utility Commission Staff. December 9, 2016.

McCullough, R., Oursland, G., Anderson, R. *Nuclear Winter.* Electricity Policy. December 2014.

McCullough, R., Vatter, M., Anderson, R., Heimensen, J., Long, S., May, C., Nisbet, A., Oursland, G. *Economic Analysis of the Columbia Generating Station*. December 2013.

TESTIMONY

Oregon Public Utility Commission (Docket No. UE 420): Opening Testimony of Rose Anderson regarding PacifiCorp's 2024 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 23, 2023.

Oregon Public Utility Commission (Docket No. UE 399): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. August 11, 2022.

Oregon Public Utility Commission (Docket No. UE 399): Opening Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 22, 2022.

Oregon Public Utility Commission (Docket No. UE 390): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's 2022 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. July 30, 2021.

Oregon Public Utility Commission (Docket No. UE 390): Opening Testimony of Rose Anderson regarding PacifiCorp's 2022 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 09, 2021.

Oregon Public Utility Commission (Docket No. UE 374): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. July 24, 2020.

Oregon Public Utility Commission (Docket No. UE 374): Opening Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 4, 2020.

Oregon Public Utility Commission (Docket No. UE 339): Opening Testimony of Rose Anderson regarding PacifiCorp's 2019 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 11, 2018.

Oregon Public Utility Commission (Docket No. UE 333): Opening Testimony of Rose Anderson regarding Idaho Power's 2018 Annual Power Cost Update. On behalf of Oregon Public Utility Commission Staff. February 12, 2018.

Oregon Public Utility Commission (Docket No. UG 325): Opening Testimony of Rose Anderson regarding Avista's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. July 20, 2017.

Oregon Public Utility Commission (Docket No. UE 319): Opening Testimony of Rose Anderson regarding Portland General Electric's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 16, 2017.

Resume updated October 2023

ATTACHMENT RA-2

NV Energy's Responses to Sierra Club Data Requests

NV Energy Response to SC DR 1-04

NV Energy Response to SC DR 1-12

NV Energy Response to SC DR 1-13

NV Energy Response to SC DR 1-14

NV Energy Response to SC DR 1-15

NV Energy Response to SC DR 1-18

NV Energy Response to SC DR 3-04

NV Energy Response to SC DR 3-06

NV Energy Response to SC DR 3-13

NV Energy Response to SC DR 3-14

NV Energy Response to SC DR 3-24

NV Energy Response to SC DR 4-01

NV Energy Response to SC DR 4-02

NV Energy Response to SC DR 5-06

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-04	**KEYWORD:**	Long-term Capacity Expansion Modeling Retrofit North Valmy SCRs
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: Capacity Expansion Modeling at North Valmy

Question: In preparing its Application for the Fifth Amendment to the 2021 IRP, did NV Energy use a long-term capacity expansion model run to inform its plan to retrofit the North Valmy plant to operate on gas and install SCRs on both the North Valmy and Tracy plant relative to alternatives?

a. If so, please provide all workpapers, results, data, inputs, and assumptions associated with that modeling.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

No. As stated in the L&R Tables subsection of the Economic Analysis Section of the narrative, page 158 of 256, "As this amendment does not include an updated load forecast, no new capacity expansion plan was developed. Instead, a revised Fourth Amendment preferred plan was used as the starting point for the capacity expansion plan for this amendment."

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-12	**KEYWORD:**	North Valmy Generating Station
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: North Valmy Generating Station

Question: For each of the Company's generating units at North Valmy Generating Station:

a. Please produce all studies of unit repowering, coal-to-gas conversion, replacement, retirement, or seasonal operations performed by the Company over the past five years.
b. Identify any transmission grid upgrades or changes that would be needed to allow for the retirement of any of the units.
c. Produce any analysis or assessment of the need for the continued operation of each unit, including but not limited to any analysis of the need for operation of repowered units through 2049.
d. Provide the remaining book value (plant balance) at the start of 2022.
e. Identify the current undepreciated book value, and the expected undepreciated book value for each year of the remaining operating life of the unit.
f. Produce any analysis or assessment of the impact that retirement of each unit would have on capacity adequacy, transmission grid stability, transmission grid support, voltage support, or transmission system reliability.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: Two

RESPONSE:

a. Analyses over the last 5 years of North Valmy Generating Station continuing operation or retirement can be found in the February 16, 2018 compliance filing for the 2016 Sierra IRP, Docket 16-07001; the 2018 Joint IRP, Docket 18-06003; the 2020 State Implementation Plan submittal to the Nevada Division of Environmental Protection (see response to Sierra Club DR 1-18 in the instant docket); the 2021 Joint IRP, Docket 21-06001; and the 5th Amendment to the 2021 IRP, Docket 23-08015. In the IRPs and Amendments, discussion of North Valmy Generating Station continuing operation or retirement can be found in the Generation section of the narrative.

b. No transmission grid upgrades or changes are needed to allow the retirement of the Valmy units.

c. Please refer to the Companies' response to part a of this request for information on the analyses conducted. The assessment of need by the Companies for additional capacity is presented in Assessment of Need subsection in the Economic Analysis narrative, page 164-166 of 256, in this filing.

d. The remaining book value at the start of 2022 can be found in Attachment01.

e. The current and expected undepreciated book value for each year assuming the current retirement date of 2025 can be found in Attachment02.

f. Please refer to the Companies response to part a of this request for information on the analyses conducted.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-13	**KEYWORD:**	Valmy 1 and 2; Past Years Analysis
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: North Valmy Generating Station

Question: For Valmy Units 1 and 2, please provide all analyses that the Company has conducted within the past five years regarding the economic viability, prudence, and/or net present value revenue requirements for customers of (i) continuing to operate the existing coal-fired units until 2028, (ii) retiring the plant by 2028, and (iii) converting the plant from coal to gas and operating the repowered gas-fired units until 2049.

a. If the Company has not performed any part of the above-described analyses, please explain why not.
b. Please identify the date and nature of each analysis performed.
c. Please provide all reports or other documentation of the results of each analysis listed in response to subpart (b)
d. Please also provide any supporting calculations, data, documents, modeling input and output files, and work papers associated with each such analysis.
e. Please indicate whether the Company has conducted any updated analysis, or plans to conduct updated analysis, since the passage of the Inflation Reduction Act, and if the Company has conducted any such analysis, please identify the date and nature of that analysis and provide all associated reports, results, and supporting calculations, data, documents, modeling input and output files, and work papers.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The analysis of continuing coal-fired operation of the Valmy Units until 2028, retiring the units in 2028, was limited to the environmental analysis presented in the instant docket. No further analysis of this option was performed due to the risks identified in the environmental analysis. The issues with operating on coal beyond 2025 are discussed in the Environmental section of the LSAP and further discussed in this Docket's Narrative, Section 5. Supply Side Plan - Generation, Section B. Environmental Regulations Impacts and Section D. Valmy Solution Pathways and Key Considerations. The case of repowering on natural gas and operating through 2049 is included in the Technical Appendix GEN-3 - Valmy LSAP.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-14	**KEYWORD:**	Tracy 4/5 Studies Unit Replacement Retirement
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: Tracy Generating Station

Question: For Units 4 and 5 at Tracy Generating Station:

a. Please produce all studies of unit replacement or retirement performed by the Company over the past five years.
b. Identify any transmission grid upgrades or changes that would be needed to allow for the retirement of any of the units.
c. Produce any analysis or assessment of the need for the continued operation of each unit through 2049.
d. Provide the remaining book value (plant balance) at the start of 2022.
e. Identify the current undepreciated book value, and the expected undepreciated book value for each year of the remaining operating life of the unit.
f. Produce any analysis or assessment of the impact that retirement of each unit would have on capacity adequacy, transmission grid stability,

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: Two

RESPONSE:

a. Analyses of continued operation of Tracy 4/5 was conducted for the Tracy 4/5 LSAP and for the 2020 State Implementation Plan ("SIP") submittal to the Nevada Division of Environmental Protection. A description of the Tracy 4/5 LSAP analysis is provided in the Generation and Economic Analysis sections of narrative in the instant docket. See pages 92-94 of 256 for the Generation portion and pages 183-184 of 256 for the Economic Analysis. Please refer to the Companies' response to SC DR 1-18 for more information on the 2020 SIP submittal.

b. No transmission grid upgrades or changes are needed to allow the retirement of Tracy 4/5.

c. Please refer to the Companies response to part a of this request for information on the analyses conducted. The assessment of need by the Companies for additional capacity is presented in Assessment of Need subsection in the Economic Analysis section of the narrative, page 164-166 of 256, in this filing.

d. The remaining book value at the start of 2022 can be found in Attachment01.

e. The current and expected undepreciated book value for each year assuming the current retirement date of 2031 can be found in Attachment02.

f. Please refer to the Companies response to part a of this request.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-15	**KEYWORD:**	Tracy 4/5 Past Years Analysis
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: Tracy Generating Station

Question: For Tracy Units 4 and 5, please provide all analyses that the Company has conducted within the past five years regarding the economic viability, prudence, and/or net present value revenue requirements for customers of (i) retiring the units by 2031 and (ii) continuing to operate the units until 2049.

a. If the Company has not performed any part of the above-described analyses, please explain why not.
b. Please identify the date and nature of each analysis performed.
c. Please provide all reports or other documentation of the results of each analysis listed in response to subpart (b)
d. lease also provide any supporting calculations, data, documents, modeling input and output files, and work papers associated with each such analysis.
e. . Please indicate whether the Company has conducted any updated analysis, or plans to conduct updated analysis, since the passage of the Inflation Reduction Act, and if the Company has conducted any such analysis, please identify the date and nature of that analysis and provide all associated reports, results, and supporting calculations, data, documents, modeling input and output files, and work papers.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a. Please refer to the Companies' response to SC data request 1-14 part a.

b. Please refer to the Companies' response to SC data request 1-14 part a. The Tracy 4/5 LSAP analysis was conducted in the first half of 2023. Please refer to the Companies' response to SC data request 1-18 for a description of the analysis conducted for the 2020 State Implementation Plan ("SIP") submittal.
c. The Tracy 4/5 LSAP analysis report and documentation are included in the instant docket in Technical Appendices GEN-4, Volume 3, pages 96-114 of 270, and ECON-4, Volume 5, pages 109-116 of 375. Please refer to the Companies' response to SC data request 1-18 for a description of the analysis conducted for the 2020 SIP submittal.

d. For the Tracy 4/5 LSAP analysis, please refer to the Companies' response to part a and part c. Please refer to the Companies' response to SC data request 1-18 for a description of the analysis conducted for the 2020 SIP submittal.

e. The Tracy 4/5 LSAP analysis was conducted after the passage of the Inflation Reduction Act. Please refer to the response to part a of this request for details pertaining to the analysis.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-10-2023
REQUEST NO:	SC 1-18	**KEYWORD:**	Environmental Compliance Investiment at Valmy and Tracy
REQUESTER:	Woolsey	**RESPONDER:**	Johns, Mathew

REQUEST:

Reference: Environmental Compliance Investiment at Valmy and Tracy

Question: Please provide all analyses that the Company has performed within the last five years regarding additional environmental compliance investments at Valmy and Tracy, including but not limited to installing selective catalytic reduction (SCR) controls or other NOx emissions controls, or installing flue gas desulfurization (FGD) or other SO2 emissions controls, that may be required to comply with final, proposed, or possible future environmental regulations including, but not limited to: regional haze rules, the federal Good Neighbor Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS), other national ambient air quality standards, proposed federal greenhouse gas emissions regulations, mercury and air toxics standards, existing consent decrees, new source review provisions, coal combustion residuals, effluent limitation guidelines, and cooling water intake standards.

a. If the Company has not performed any of the above-described analyses, please explain why not.

b. For each planned or potential environmental compliance investment referenced above, please identify the projected capital and annual O&M costs of each investment at each generating unit at the Valmy and Tracy plants.

c. Please provide all supporting analyses, calculations, data, documents, modeling input and output files, and work papers associated with each potential investment referenced above.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

As part of the Integrated Resource Plan 5th Amendment filing (filing), detailed discussion of key environmental regulations and impacts was prepared as part of the Supply Plan-Generation, including the Regional Haze Rule, Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards ("NAAQS"), proposed Greenhouse Gas Rule, and proposed changes to the Mercury and Air Toxics Standards. Generation Technical Appendices 3 and 4 contain the Life Span Analysis Process for Valmy and Tracy 4/5 that considered the potential operation and maintenance and capital budgets, including potential investment in emission controls for continued operation. As explained in the filing, selective catalytic reduction emission controls were assumed for both the Valmy natural gas conversion and Tracy 4/5 continued operation for planning purposes, subject to re-evaluation under Regional Haze and permitting, which may include review of new source provisions.

As explained in the filing, both Valmy and Tracy 4/5 were included in the Regional Haze Planning Period commencing in 2018. NV Energy submitted its initial 4-factor analysis to the Nevada Division of Environmental Protection (NDEP) in March 2020. NV Energy received several follow-up requests for further information, as well as requests for specific revisions to the submitted analysis from NDEP based on its internal review as well as input from other stakeholders such as Environmental Protection Agency (EPA), Federal Land Managers, and public comment. The entirety of NDEP's State implementation plan (SIP) submittal, including all the NV Energy 4-factor analyses, can be accessed online at NDEP's regional Haze SIP webpage (Regional Haze | NDEP (nv.gov). The link to Appendix B on the webpage contains the 4-factor analysis and follow-up responses to requests for Tracy and Valmy Generating Stations. As explained in the filing, the 4-factor analyses are being updated as part of the planning and permitting process in the event the projects are approved by the commission such that the SIP revision may be submitted to the EPA and NDEP permitting can be finalized in a timely manner.

The Supply Plan-Generation also includes a discussion of the potential retirement actions to be taken after Valmy post-natural gas conversion under both state and the Federal Coal Combustion Residuals Rule. The Valmy ash landfill is the only regulated coal combustion residuals facility at Valmy. Compliance data related to the Valmy ash landfill is publicly posted at https://www.brkenergy.com/ccr/nve.htm . The Tracy plant is not subject to the Federal Coal Combustion Residuals Rule.

With respect to the 316b cooling water intake standards, the Nevada Division of Environmental Protection issued a permit on October 1, 2023, allowing operation of the intake above 2.0 million gallons per day. U.S Fish and Wildlife Service was a cooperating agency as part of the permitting process. Prior to the permit issuance, the intake was limited to operate at less than 2 million gallons per day, thus not requiring a permit specific to 316b requirements. No capital investment was required to obtain the permit.

Effluent Limitation Guidelines are not applicable to Valmy or Tracy as they are zero-discharge facilities. Neither facility is subject to consent decrees. With respect to other national ambient air quality standards, changes to existing regulation, or new regulation, we will continue to assess impacts to the operating facilities.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-04	**KEYWORD:**	valmy tracy alternatives; analysis comparing cost meeting energy capacity needs
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: Valmy and Tracy Alternatives

Question: Please identify and produce each and any analysis carried out in the past five years comparing the cost of meeting the energy and capacity needs that provide the basis for the North Valmy and Tracy projects with the cost of the following alternatives:

a. Energy efficiency.
b. Battery storage.
c. Demand response.
d. Market purchases.
e. Power purchase agreements
f. Existing natural gas combined cycle or combustion turbine capacity.
g. New natural gas combined cycle or combustion turbine capacity.
h. Conversion of natural gas combustion turbines to natural gas combined cycle units.
i. Combined heat and power.
j. Wind.
k. Solar.
l. Solar and battery combined.
m. Geothermal.
n. Any combination of the above resources.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a. No analyses were conducted replacing Valmy or Tracy 4/5 with energy efficiency.
b. Please refer to the Companies' response to SC 1-12. No analyses were conducted replacing Tracy 4/5 with battery storage.
c. No analyses were conducted replacing Valmy or Tracy 4/5 with demand response.
d. Please refer to the Companies' responses to SC 1-12 and SC 1-15.
e. No analyses were conducted replacing Valmy or Tracy 4/5 with a specific power purchase agreement. If the question referred to an unspecified power purchase agreement, please refer to the Companies' responses to part d.
f. No analyses were conducted replacing Valmy or Tracy 4/5 with existing natural gas combined cycle or combustion turbine capacity.
g. Please refer to the Companies' response to SC 1-12. No analyses were conducted replacing Tracy 4/5 with natural gas combined cycle or combustion turbine capacity.
h. No analyses were conducted replacing Valmy or Tracy 4/5 with the conversion of natural gas combustion turbines to natural gas combined cycle units.
i. The Companies are unsure of the intent of item i,"combined heat and power." Please refer to the Companies' responses to SC 1-12 and SC 1-15 which contain references to all analyses conducted in the last 5 years related to the replacement of Valmy and/or Tracy 4/5.
j. No analyses were conducted replacing Valmy or Tracy 4/5 with wind.
k. Please refer to the Companies' response to SC 1-12. No analyses were conducted replacing Tracy 4/5 with solar.
l. Please refer to the Companies' response to SC 1-12. No analyses were conducted replacing Tracy 4/5 with solar and battery combined.
m. No analyses were conducted replacing Valmy or Tracy 4/5 with geothermal.
n. Please refer to the Companies' responses to SC 1-12 and SC 1-15 which contain references to all
o. analyses conducted in the last 5 years related to the replacement of Valmy and/or Tracy 4/5.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-06	**KEYWORD:**	valmy tracy operational changes comply environmental policy analysis
REQUESTER:	Woolsey	**RESPONDER:**	Johns, Mathew

REQUEST:

Reference: Valmy and Tracy

Question: Please provide all analyses that the Company has performed within the last three years regarding potential operational changes (not capital investments) at Valmy and Tracy that may help comply with final, proposed, or possible future environmental regulations including, but not limited to: regional haze rules and the federal Good Neighbor Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS). If the Company has not performed analysis of the potential to comply with environmental policy through operational changes instead of capital investments at these units, please explain why not.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Please refer to the response Sierra Club Data Request 1-18, and the detailed discussion of these regulation and impacts to Valmy or Tracy 4/5 prepared as part of the Supply Plan – Generation.

As discussed in the Supply Plan – Generation narrative, technically feasible emission controls are being re-assessed as part of the Regional Haze Rule for both Valmy Units 1 and 2 and Tracy 4/5 in lieu of federally enforceable retirement dates of 2028 and 2031, respectively.

Under the federal Good Neighbor plan, if it becomes effective following the current stay in Nevada, Valmy Units 1 and 2 will be allocated fewer NOx allowances in 2026 based on a lower NOx emission rate and further reduction of NOx allowances in 2027 to a level commensurate with SCR controls. Without NOx emission controls, operation of Valmy Units 1 and 2 will become limited during the 2026 ozone season (May – September) and further constrained starting in 2027 to levels that would not be able to meet operational conditions, such as reliability must-run requirements required one or both units to be available.

For these reasons, operational changes alone would not meet the requirements identified in the filing as well as the regulations.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-13	**KEYWORD:**	cost converting north valmy retire converted plant prior 2049
REQUESTER:	Woolsey	**RESPONDER:**	Allen, Barbara

REQUEST:

Reference: Valmy

Question: Please indicate whether NV Energy has evaluated the cost of converting North Valmy to operate on gas but retiring the converted plant prior to 2049. Explain how the proposed 2049 retirement date for the repowered North Valmy plant was selected.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Please refer to the Companies' response to SC 1-12. In the February 16, 2018, compliance filing for the 2016 Sierra IRP, Docket 16-07001, the Companies analyzed an option to convert one Valmy unit to operate on natural gas and retire the converted unit prior to 2049.

The proposed 2049 retirement date was chosen to match the retirement dates of the majority of the generating fleet as proposed in the Fourth Amendment to the 2021 IRP (Docket No. 22-11032) and as modified by the Commission's Order in that docket.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-14	**KEYWORD:**	inflation reduction act IRA tax credits, decision convert north valmy
REQUESTER:	Woolsey	**RESPONDER:**	Patchett, Kevin

REQUEST:

Reference: Inflation Reduction Act

Question: Please indicate whether NV Energy incorporated the impacts of the Inflation Reduction Act (IRA) tax credits into its analysis and decision to convert North Valmy to operate on gas and extend the lives of Tracy units 4 and 5.

a. If yes, explain how the tax credits were incorporated into the Company's analysis and detail the Company's assumptions, including which tax credits and bonus adders were modeled or considered.
b. If no, explain why NV Energy didn't model or consider IRA tax credits.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a. Extend life of Tracy units 4&5
Extending the life of the Tracy 4 & 5 units are not eligible renewable projects under the Inflation Reduction Act for Investment Tax Credits or Production Tax Credits and therefore were excluded from the financial analysis model.

b. As part of the financial analysis and modeling, IRA tax credits were considered with each project the Company reviewed for inclusion in this IRP. Determinations were made as to if the project qualified in whole or part and if any credits were applicable they were included in the analysis.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-24	**KEYWORD:**	energy delivered carlin trend load pocket retail customers DOS
REQUESTER:	Woolsey	**RESPONDER:**	Guerrero, David

REQUEST:

Reference: Carlin Trend Load Pocket

Question: What percentage of the energy NV Energy delivers to the Carlin Trend Load Pocket is for retail energy customers of NV Energy? What percentage of the energy the Company delivers to the Carlin Trend Load Pocket is for Distribution Only Service?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Approximately 29 % of the energy delivered by NV Energy to the Carlin Trend Load Pocket is for retail energy customers and 71 % is for Distribution only service customers.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	11-08-2023
REQUEST NO:	SC 4-01	**KEYWORD:**	
REQUESTER:	Woolsey	**RESPONDER:**	Lateef, Shahzad

REQUEST:

Reference: Greenlink West

Question: Please confirm that the currently planned in-service date for the Greenlink West Transmission Project is the end of December 2026. If not, please explain.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Currently planned in-service date for Greenlink West is May 2027. A permitting schedule published by the Bureau of Land Management in August 2023 indicates an eleven-month delay in permitting of Greenlink West from the originally published permitting schedule. NV Energy intends to compress construction schedule by 6 months. An additional five month in permitting delay is reflected by a delayed in-service date for Greenlink West.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	11-08-2023
REQUEST NO:	SC 4-02	**KEYWORD:**	Greenlink North In-service Date December 2027
REQUESTER:	Woolsey	**RESPONDER:**	Lateef, Shahzad

REQUEST:

Reference: Greenlink North

Question: Please confirm that the currently planned in-service date for the Greenlink North Transmission Project is the end of December 2027. If not, please explain.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The planned in-service date for Greenlink North is December 2028. This in-service date reflects the originally proposed and approved date for Greenlink North as a part of NV Energy's 2021 filing in response to Nevada SB448 Transmission Infrastructure for Clean Energy Economy Plan (TICEEP - Docket # 21-06001)

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	11-09-2023
REQUEST NO:	SC 5-06	**KEYWORD:**	Valmy Tracy NOx Emissions 2022
REQUESTER:	Woolsey	**RESPONDER:**	Johns, Mathew

REQUEST:

Reference: Valmy and Tracy NOx Emissions

Question: Please provide the total NOx emissions at each of the following units in 2022: a. Valmy Unit 1 b. Valmy Unit 2 c. Tracy Unit 4 d. Tracy Unit 5

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The total NOx emissions for Valmy Unit 1, Valmy Unit 2, and Tracy 4/5 for 2022 are summarized below. Please note that Tracy 4/5 is a single natural gas-fired combustion turbine with a heat recovery steam generator in combined cycle mode. These emissions were used in responding to Sierra Club data requests 3-029 and 5-010.

Valmy Unit 1 total NOx emissions for 2022: 1028.001 short tons (or 2,056,002 lbs)
Valmy Unit 2 total NOx emissions for 2022: 1241.332 short tons (or 2,482,664 lbs)
Tracy 4/5 total NOx emissions for 2022: 231.361 short tons (or 462,722 lbs)

ATTACHMENT RA-3

Excerpt of Nevada Division of Environmental Protection and Nevada Department of Conservation & Natural Resources, Regional Haze State Implementation Plan Revision For the Second Planning Period (pp. ES-1–1-20, 5-1–5-51) (Aug. 2022)

NEVADA REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR THE SECOND PLANNING PERIOD

A Plan for Implementing
Section 308 (40 CFR § 51.308)
of the Regional Haze Rule

Second Implementation Period (2018-2028)

NEVADA DIVISION OF
ENVIRONMENTAL PROTECTION
Nevada Department of
CONSERVATION & NATURAL RESOURCES

State of Nevada
Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, Nevada 89701

August 2022

EXECUTIVE SUMMARY

The federal Regional Haze Rule (RHR) requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to regional haze in each mandatory Class I area (CIA) located in Nevada and each mandatory CIA located in nearby or neighboring states. Jarbidge Wilderness Area (WA) is the only mandatory CIA located in Nevada. Under the RHR, Nevada is required to submit a State Implementation Plan (SIP) addressing the specific elements required by the RHR. This document serves as the State of Nevada's SIP submittal provided to the U.S. Environmental Protection Agency (EPA) Region 9 to satisfy the rule requirements outlined in 40 CFR Part 51, Subpart P, Section 51.308. This submittal is a revision to the regional haze SIP that Nevada submitted for the initial implementation period of the rule and amends the first round SIP when adopted.

The RHR covers a long period, broken into several planning phases to ultimately meet the national goal of returning visibility at all designated CIAs to natural conditions. The approach taken in preparing this RH SIP is to address the second planning period (2018 through 2028). Assuming natural visibility conditions are achieved by 2064, this plan meets the requirements of improving visibility for the most impaired days and ensuring no degradation in visibility for the clearest days for the period ending in 2028, the second planning period in the federal rule. Nevada's RH SIP has been prepared by the Nevada Division of Environmental Protection (NDEP) and contains strategies and elements related to each requirement of the federal rule. The SIP is based on data that existed as of December 2021.

Calculations of Baseline, Current, and Natural Visibility Conditions; Progress to Date; and the Uniform Rate of Progress

The RHR at 40 CFR 51.308(f)(1) requires the state to calculate baseline, current, and natural visibility conditions, which in turn are used to calculate progress to date and the uniform rate of progress (URP) per year necessary to achieve natural conditions by 2064. Although achieving natural visibility conditions by 2064 is not required by the RHR, or part of the national visibility goal, it is used by states as a reference point to develop the URP metric and measure progress between each decadal implementation period. To develop the URP, or glidepath, states must determine baseline visibility conditions for the period 2000 through 2004, current visibility conditions for the period 2014-2018, and natural background visibility conditions to be achieved by 2064. Achievement of natural visibility conditions by 2064 is only measured among the 20 percent "most-impaired" days (excluding episodic events like wildfire) of each year, while the 20 percent "clearest" days must not degrade beyond the 20 percent clearest days of the baseline visibility conditions measured during the first round.

NDEP has calculated the baseline, current, and natural visibility conditions record at Jarbidge WA during both the most impaired days and clearest days. During the most impaired days, visibility conditions at Jarbidge WA have shown a steady improvement in visibility since the baseline conditions were calculated during the initial implementation period and confirms that visibility conditions at Jarbidge WA are on track to achieve natural conditions by 2064. During the clearest days, NDEP has confirmed that current visibility conditions have not degraded since the previous round.

An analysis of pollutant species contributing to visibility impairment at Jarbidge WA, for both the most impaired and clearest days, indicates that ammonium sulfate (originating from anthropogenic sulfur dioxide emissions) and organic mass carbon (typically originating from wildfire emissions) are the top two pollutants of concern. Beyond these two pollutants, coarse mass (typically originating from windblown dust events and fugitive dust) is the third pollutant of concern. Ammonium nitrate (originating from anthropogenic oxides of nitrogen emissions) becomes a more significant visibility impairing pollutant at Jarbidge WA during the winter months. This data suggests that visibility at Jarbidge WA is significantly impacted by both anthropogenic and natural sources. High levels of organic mass carbon indicate that wildfire emissions still interfere with Nevada's ability to track visibility progress, despite the efforts of the new "most-impaired days" metric that aims to remove wildfire impacts.

Long-term Strategy for Regional Haze

The RHR at 40 CFR 51.308(f)(2) requires the state to submit a long-term strategy that addresses regional haze visibility impairment at all mandatory Class I areas that may be impacted by emissions from the state. The strategy must include enforceable emissions limitations, compliance schedules and other measures as necessary to achieve the state's reasonable progress goals. As part of the technical basis for the long-term strategy, the state must identify its baseline emissions inventory and all anthropogenic sources of visibility impairment. This SIP covers long-term strategies for visibility improvement between current conditions and visibility conditions projected for 2028.

An emission inventory, organized by sector and pollutant species, is provided for the current and 2028 projection conditions (representing the outcome of this SIP's efforts to improve visibility). In NDEP's projection of 2028 conditions, statewide emissions of visibility impairing pollutants are tremendously dominated by volatile organic compounds from natural biogenic emissions followed by coarse particulate matter from fugitive dust emissions. Statewide sulfur dioxide and nitrogen of oxides emissions, the anthropogenic pollutants considered for further reductions by NDEP, are miniscule compared to other pollutants and account for a small percentage of total statewide visibility impairing pollutants.

Visibility and source apportionment modeling show that Nevada's reduction in visibility impairing pollutants during the second implementation period will aid Jarbidge WA, and other out-of-state CIAs, in achieving the necessary visibility improvements toward natural conditions. Visibility projections for Jarbidge WA in 2028 show that enough visibility improvement will be achieved, as a result of the emission reductions of this round, to remain on track toward natural visibility conditions by 2064. Because of this, no further emission reductions are needed for the second implementation period.

To achieve additional emission reductions in Nevada as part of the SIP's Long-Term Strategy, NDEP identified eight point sources that reasonably emit pollutants impacting visibility impairment at Jarbidge WA. NDEP determined additional emission reduction measures necessary at each facility to achieve reasonable progress for the second implementation period by considering the four statutory factors: cost of compliance, time necessary for compliance, energy and non-air quality impacts, and the remaining useful life of the source. NDEP concluded that the closure of three electrical generating units, implementation of add-on controls at a lime production plant, new emission limits for existing controls at a facility, and the continued use of several existing controls are all necessary to achieve reasonable progress for this round.

Monitoring Strategy

The RHR at 40 CFR 51.308(f)(6) requires the state to develop a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I areas within Nevada.

Visibility conditions in mandatory Class I areas throughout the United States are presently measured by the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network, which is operated and maintained through a formal cooperative relationship between USEPA and Federal Land Manager (FLM) agencies. Nevada commits to continue using the IMPROVE monitoring data and to update Nevada's emissions inventory periodically, as required by the RHR. The inventory updates will be used for state tracking of emission changes and trends, to provide input into the evaluation of whether reasonable progress goals will continue to be achieved at Jarbidge WA and for other regional analyses.

State and Federal Land Manager Coordination

The RHR at 40 CFR 51.308(f)(2)(ii) requires states to coordinate with other states during the development of reasonable progress goals and emission management strategies. Nevada has met these requirements through participation in the Western Regional Air Partnership (WRAP) and commits to continue to coordinate via the WRAP for future implementation periods. In the WRAP process, Nevada participated in various forums and workgroups to help develop a coordinated emissions inventories and analyses of the impacts that sources have on regional haze in the west. In more direct discussions with neighboring states, NDEP has confirmed that no out-of-state Class I areas are reliant on further emission controls in Nevada beyond what is proposed in this SIP in order to achieve reasonable progress by the end of the second planning period.

40 CFR 51.308(i) further requires states to coordinate with FLMs in developing the RH SIP. States must provide a contact to whom FLMs can submit recommendations on the implementation of the RHR; provide FLMs an opportunity for consultation at least 60 days prior to holding any public hearing on the SIP; provide a public record of how the state addressed any FLM comments; and provide procedures for continuing consultation with FLMs on the implementation of the state's RH SIP. A draft of Nevada's RH SIP was provided to the FLMs with a 60-day comment period prior to the public hearing on the SIP. Documented in this SIP, NDEP has addressed comments provided by the FLMs before the commencement of public comment. NDEP commits to continuing these consultations with the FLMs in future planning periods.

Summary Figures and Tables

Figure ES-1 illustrates the observed visibility conditions at Jarbidge Wilderness Area, sorted by visibility impairing pollutants in ambient air. During the baseline years, from 2000 through 2004, the most impaired days are largely impacted by ammonium sulfate (32%), organic mass carbon (28%), and coarse mass (17%). During the same period for the clearest days, ammonium sulfate continues to dominate (42%), followed by organic mass carbon (27%). During the current period, from 2014 through 2018, the same trend continues with the most impaired days largely impacted by ammonium sulfate (29%), organic mass carbon (29%), and coarse mass (22%). The clearest days are impacted by the same three pollutant species: ammonium sulfate (42%), organic mass carbon (27%), and coarse mass (13%). Note that during the clearest days for both periods, which typically occur during the winter months, ammonium nitrate extinction contribution jumps up (~10%).

Table ES-1 outlines the incremental change in visibility conditions at Jarbidge WA across all major time periods (baseline, current, 2028 projection, and 2064 goal of natural conditions) and indicates a consistent downward trend in visibility impairment, or regional haze, during the most impaired days that is on track to achieve natural conditions by 2064. A similar downward trend is observed during the clearest days toward estimated natural conditions at Jarbidge WA, however, the RHR only requires that visibility conditions not degrade beyond the baseline conditions. Table ES-1 shows that the projected visibility condition during the clearest days in 2028 (1.72 dv) does no degrade beyond the baseline condition (2.56 dv).

Figure ES-2 graphically displays the visibility conditions outlined in Table ES-1 and compares these values to the uniform rate of progress (solid green line), clearest days baseline (solid brown line) and observed annual visibility conditions for both the most impaired days (dashed light blue line) and clearest days (dashed orange line). The figure shows that in order to achieve that national goal of natural visibility conditions of 7.39 dv by 2064, projected visibility conditions in 2028 at Jarbidge WA must be at least 8.20 dv, or below. NDEP predicts that visibility conditions during the most impaired days at Jarbidge WA will be 7.76 dv in 2028. NDEP also predicts that visibility conditions during the clearest days will be 1.72 dv in 2028, well below the goal of 2.56 dv.

Table ES-2 outlines the total emissions reductions in tons per year expected as a result of Nevada's Long-Term Strategy for the second implementation period. These reductions are achieved from new control measures identified as necessary to achieve reasonable progress after consideration of the four statutory factors. As seen in the table, roughly 2,300 tons per year of NO_x and SO_2 emissions are expected, or a total of 4,600 tons per year.

Figure ES-1: Baseline and Current Visibility Conditions for the Most Impaired and Clearest Days by Pollutant Species

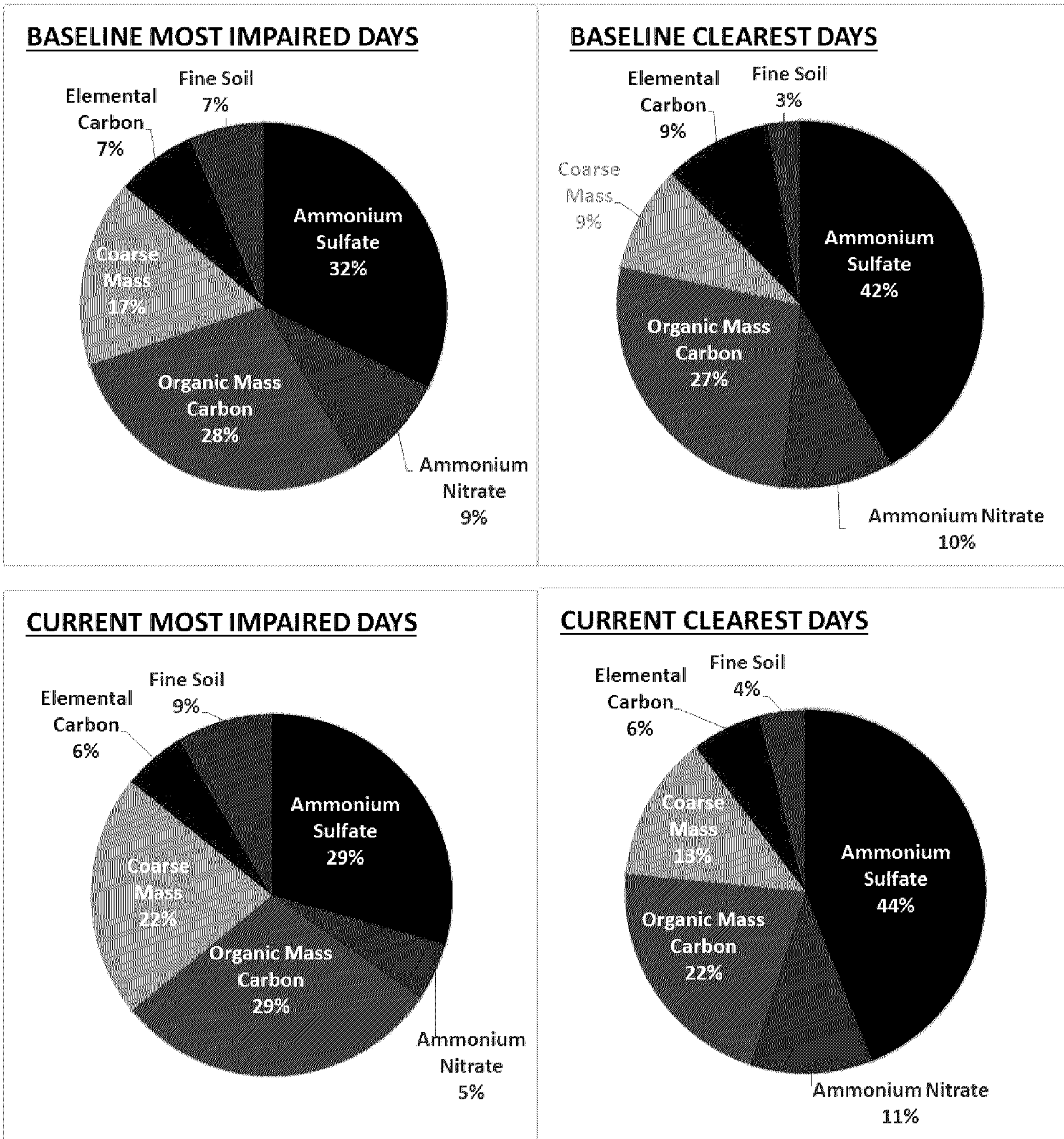

Table ES-1: Visibility Progress at Jarbidge Wilderness Area Toward National Goal of Natural Visibility Conditions by 2064 (deciviews)

Period	Years	Most Impaired Days Average	Clearest Days Average
Baseline Condition	2000-2004	8.73	2.56
Current Condition	2014-2018	7.97	1.84
Projected Condition	2028	7.76	1.72
Natural Condition Goal	2064	7.39	1.14

Figure ES-2: Uniform Rate of Progress for Jarbidge Wilderness Area

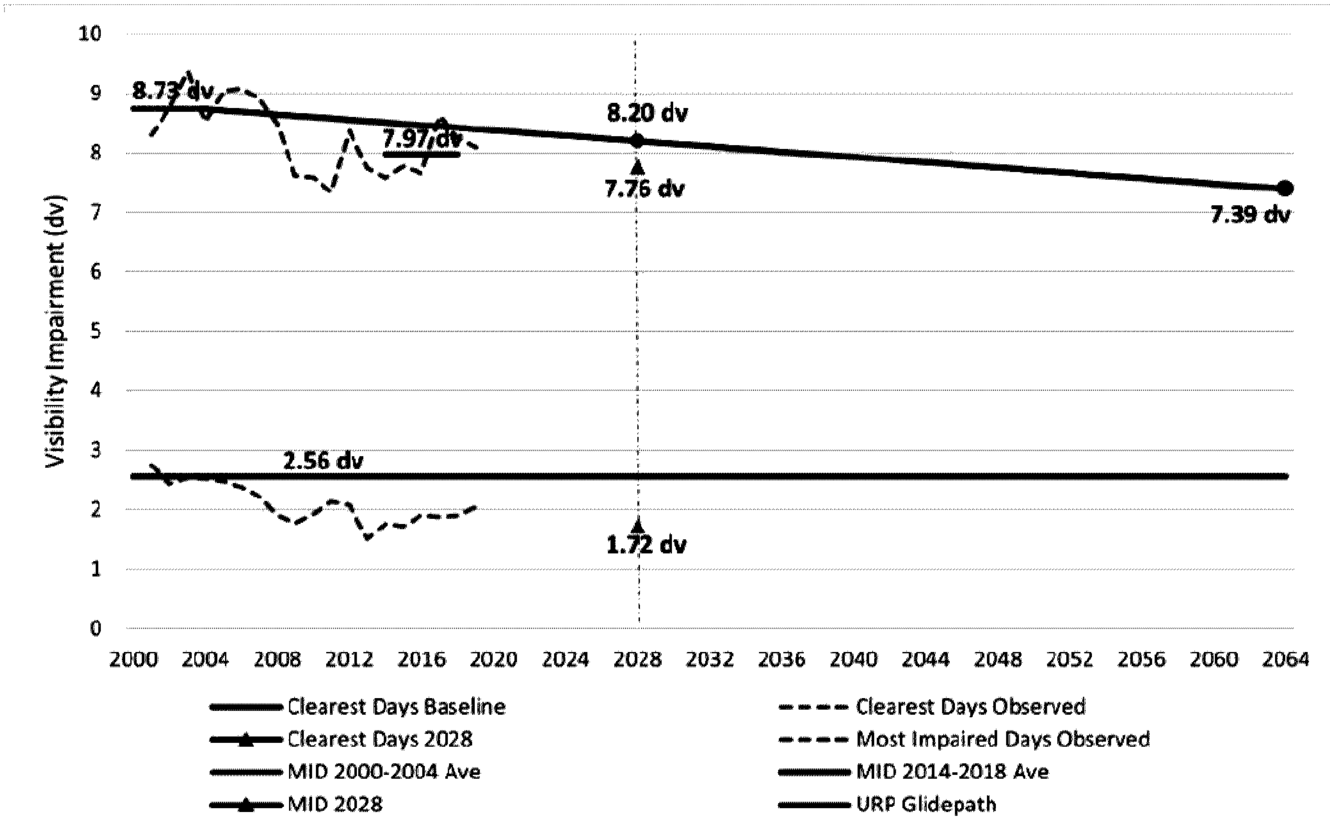

Table ES-2: Long-Term Strategy Emissions Reductions

NO_x	SO_2	PM_{10}	Total
2,239	2,313	60	4,612

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Acronyms, Abbreviations and Terms

2014v2	2014 Emissions Inventory Version 2
2028OTBa2	2028 On-the-Books/On-the-Way Emission Inventory Version 2
2028PAC2	2028 Potential Additional Controls Emission Inventory Version 2
AMET	EPA Atmospheric Model Evaluation tool
ARP	Acid Rain Program
BART	Best Available Retrofit Technology
BACT	Best Available Control Technology
BLM	Bureau of Land Management
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CARB	California Air Resources Board
CASTNET	Clean Air Status and Trends monitoring network
CCDES	Clark County Department of Environment and Sustainability
CD	Consent Decree
CIA	Class I Area
CENWRAP	Central West Regional Air Partnership
CFR	Code of Federal Regulations
CM	Coarse Matter
CSN	Chemical Speciation Network
CTI	Cleaner Trucks Initiative
DERA	Diesel Emissions Reduction Act
EGU	Electrical Generating Unit
EIMP	Emission Inventories and Modeling Protocol Work Group
EJ	Environmental Justice
EWRT	Extinction-Weighted Residence Time
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
FLM	Federal Land Manager
FSWG	Fire and Smoke Work Group
FWS	Fish & Wildlife Service
GEOS-Chem	Goddard Earth Observing System global chemical model
GHG	Greenhouse Gas
HI	Haze Index
HMS	Hazard Mapping System
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWDW	Intermountain West Data Warehouse
JARB1	Jarbidge Wilderness Area IMPROVE Monitor
LNB	Low-NO_x Burner(s)
LEV	Low-Emission Vehicle
LTS	Long-Term Strategy
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
Mm^{-1}	Inverse Megameter
MOU	Memorandum of Understanding
MOVES	Motor Vehicle Emission Simulator
MW	Megawatts

NAAQS	National Ambient Air Quality Standards
NAC	Nevada Administrative Code
NDEP	Nevada Division of Environmental Protection
NEI	National Emission Inventory
NEIv2	National Emission Inventory version 2
NG	Natural Gas
NPS	National Park Service
NRS	Nevada Revised Statutes
NSR	New Source Review
NTEC	National Tribal Environmental Council
OFA	Over-Fired Air
OGWG	Oil & Gas Work Group
PNG	Pipeline Natural Gas
PSAT	Particulate Source Apportionment Technology
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RAVI	Reasonable Attributable Visibility Impairment
RepBase2	Representative Baseline Emission Inventory Version 2
RH	Regional Haze
RHPWG	Regional Haze Planning Work Group
RHR	Regional Haze Rule
RMC	Regional Modeling Center
RPG	Reasonable Progress Goal(s)
RPO	Regional Planning Organizations
RPS	Renewable Portfolio Standard
RRF	Relative Response Factor
SCR	Selective Catalytic Reduction
SEC	State Environmental Commission
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kerner Emissions
SNCR	Selective Non-Catalytic Reduction
TSS	Technical Support System
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
URP	Uniform Rate of Progress
VIEWS	Visibility Information Exchange Web System
WA	Wilderness Area
WAQS	Western Air Quality Study
WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WGA	Western Governors Association
WPS	WRF Preprocessing System
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting
ZEV	Zero-Emission Vehicle

Chemicals and Chemical Compounds

CO	Carbon Monoxide
EC	Elemental Carbon
HNO_3	Nitric Acid
NH_3	Ammonia
NH_4	Ammonium
NH_4NO_3	Ammonium Nitrate
$(NH_4)_2SO_4$	Ammonium Sulfate
NMHC	Non-Methane Hydrocarbons
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrate
NO_x	Oxides of Nitrogen
OC	Organic Carbon
OMC	Organic Matter Carbon
$PM_{2.5}$	Fine Particulate Matter (2.5 micrometers and smaller in diameter)
PM_{10}	Coarse Particulate Matter (10 micrometers and smaller in diameter)
POA	Primary Organic Aerosols
SO_2	Sulfur Dioxide
SO_4	Sulfate
VOC	Volatile Organic Compounds

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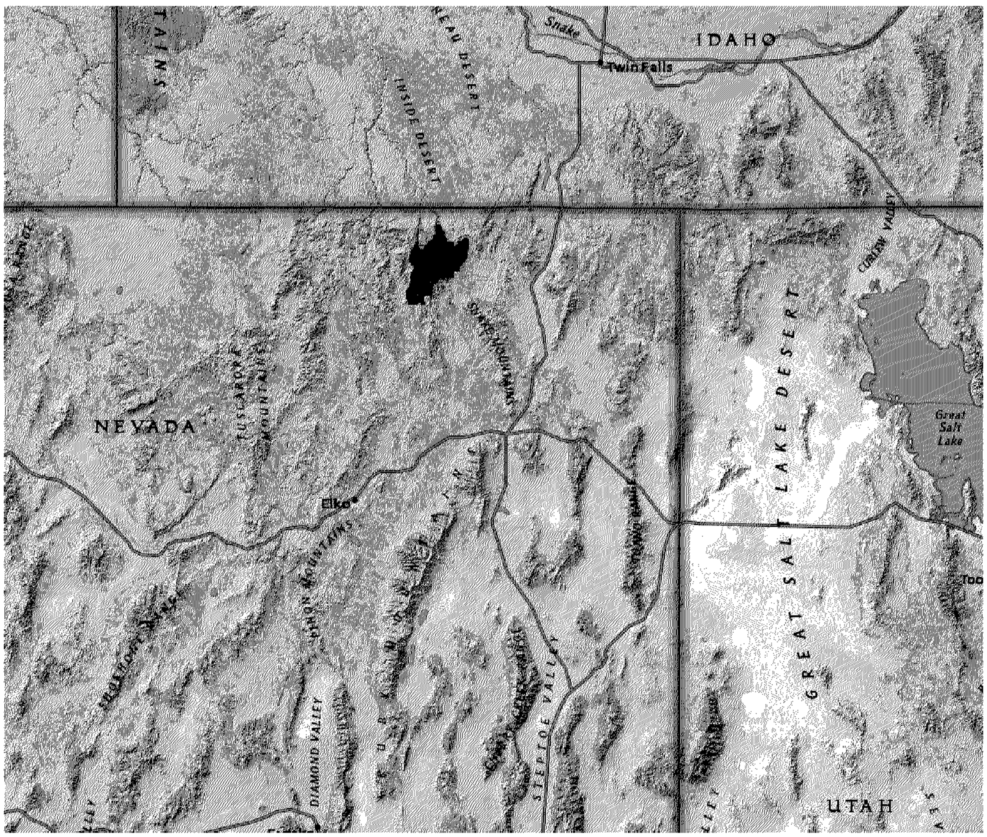
Chapter One – Overview

1.1 NEVADA'S CLASS I AREA – JARBIDGE WILDERNESS AREA

Nevada has one mandatory Class I Area, the 113,167-acre Jarbidge Wilderness Area (Jarbidge WA), located within the Humboldt National Forest in the northeastern portion of Nevada, as shown on Figure 1-1.

FIGURE 1-1

JARBIDGE WILDERNESS AREA LOCATION



Jarbidge WA lies near the Idaho border just north of the physical geographic boundary separating the Columbia Plateau region, including the Snake River Plain, and the Great Basin region to the south. It consists of the headwaters basin of the Jarbidge River East Fork that flows north from the center of the wilderness area, and the headwaters basin of Marys River that flows south from the center of the wilderness area, part of the Columbia River/Great Basin hydrographic divide. The terrain encompassed by the wilderness area consists of deep canyons with steep slopes. The Jarbidge River Canyon, which comprises the upper main headwaters of the Jarbidge River proper, is oriented south to north, with its mouth several miles to the north where it drains into the Bruneau River.

The area illustrates Nevada's typical basin and range topography with elevations ranging from 2,100 m (6,900 ft) where the Jarbidge River East Fork exits the wilderness into Idaho's Snake

River Plains to eight peaks over 3,000 m (~10,000 ft) high along the Jarbidge Mountain crest, which includes the highest peak, Marys River Peak at 3,170 m (10,398 ft).

Unlike the rest of the state, Jarbidge WA is unusually wet, with an average of 7-8 ft of total snowfall and 1-2 ft of total precipitation. The varied terrain is cut by deep canyons with steep slopes and supports a range of vegetation zones from sagebrush flats to glaciated alpine basins. During the warmer months, these scenic vistas and their 150 miles of hiking trails are a major tourist attraction.

1.2 VISIBILITY IMPAIRMENT

Regional haze is pollution from disparate sources that impairs visibility over a large region, including national parks, forests and wilderness areas (156 of which are termed mandatory federal Class I areas). Regional haze is caused by sources and activities emitting fine particles and their precursors. Those emissions are often transported over large regions. Particles affect visibility through the scattering and absorption of light, and fine particles – particles similar in size to the wavelength of light – are most efficient, per unit of mass, at reducing visibility. Fine particles may either be emitted directly or formed from emissions of precursors, the most important of which are sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Reducing fine particles in the atmosphere is generally considered to be an effective method of reducing regional haze, and thus improving visibility. Fine particles also adversely impact human health, especially respiratory and cardiovascular systems.

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources include windblown dust and smoke from wildfires. Anthropogenic sources include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Higher concentrations of pollutants result in more absorption and scattering of light, which reduce the clarity and color of a scene. Some types of particles, such as sulfates, are more effective at scattering light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye, and the object may be a single viewing target or scene.

In the 156 mandatory Class I areas across the country, visual range has been substantially reduced by air pollution. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Much of the visibility impairment in the West can be attributed to natural emissions of smoke and dust with significant contributions resulting from international emissions from beyond the boundaries of the United States, including Canada and Mexico.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to very small particles in the air has been linked with increased respiratory illness, decreased lung function and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers and streams unsuitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings, or other natural and manmade structures.

1.3 THE WESTERN REGIONAL AIR PARTNERSHIP AND NEVADA

USEPA initially funded five Regional Planning Organizations throughout the country to coordinate regional haze rule-related activities between states in each region. Nevada belongs to the Western Regional Air Partnership (WRAP), the consensus organization of western states, tribes, and federal agencies, which oversees analyses of monitoring data and preparation of technical reports regarding regional haze in the western United States.

The WRAP was formed in September 1997 as the successor organization to the Grand Canyon Visibility Transport Commission. It is administered jointly by the Western Governors Association (WGA) and the National Tribal Environmental Council (NTEC). The mission of the WRAP is to identify regional or common air management issues and to develop and implement strategies to address these issues. The WRAP is a partnership of states and tribes as well as federal agencies and was designated by USEPA to assist western states in the development of regional haze plans. It provides a coordination mechanism with regard to science and technology support for policy and programmatic uses in the western United States.

WRAP member states include Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Federal participants are the Department of the Interior (National Park Service and Fish & Wildlife Service,) the Department of Agriculture (Forest Service) and USEPA.

Work by WRAP committees, forums and workgroups is accomplished by the staff time contributed by state, tribal, Federal Land Manager (FLM), EPA and environmental, industry and public representatives, with the support of WRAP staffing through WGA and NTEC. WRAP work is also handled through contracts to environmental consulting firms, to analyze air pollution data collected by states and tribes in their regulatory programs as well as to prepare data and analyses for natural and/or uncontrollable air pollution sources.

The WRAP established stakeholder-based technical and policy oversight committees to assist in managing the development of regional haze work products. Working groups and forums were established to develop technical tools and work products the states and tribes needed to develop their implementation plans. Much of the WRAP's effort focused on regional technical analysis, which is the basis for developing strategies to meet the Regional Haze Rule (RHR) requirement to demonstrate reasonable progress towards natural visibility conditions in Class I areas. This includes the compilation of emission inventories, air quality modeling and ambient monitoring and data analysis.

The WRAP has developed a regionally-consistent and comparable body of technical data and analysis tools that has been invaluable in addressing regional haze in the west. These data and tools are provided for use and evaluation through a transparent and open network of interrelated data support web systems and a technical decision support system:

WRAP Technical Data Support Centers

- Intermountain West Data Warehouse (https://views.cira.colostate.edu/iwdw/): IWDW provides easy online access to monitored air quality data, gridded modeling products, emissions data, and an integrated suite of tools to help assess air quality on Federal lands.

WRAP Technical Decision Support System

- Technical Support System (http://views.cira.colostate.edu/tssv2/): TSS integrates a number of different data support resources under one web-based decision support umbrella for regional haze planning and implementation.

In addition to these technical tools and work products, the WRAP has provided a forum for coordination and consultation with other states, tribes and FLMs. The major amount of interstate consultation in the development of this SIP was through the Regional Haze Planning Work Group (RHPWG) of the WRAP. Nevada participated in the RHPWG, which took the products of the WRAP technical analysis and consultation process and developed a process for establishing reasonable progress goals in the western Class I areas. Chapter Nine of this document discusses the process that Nevada participated in to address the consultation requirements with FLMs, tribes and other WRAP states during the development of this plan and Nevada's commitments for future consultation.

1.4 TECHNICAL SUPPORT BACKGROUND

1.4.1 Regional Haze Monitoring Network

In response to the 1977 Clean Air Act Amendments, the IMPROVE program was established in 1985 to aid the creation of federal and state implementation plans for the protection of visibility in Class I areas. Air monitoring devices at these locations are operated and maintained through a formal cooperative relationship between the USEPA and the National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management and U.S. Forest Service, collectively called the FLMs. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators, the Association of Local Air Pollution Control Officials, Western States Air Resources Council, Mid-Atlantic Regional Air Management Association and Northeast States for Coordinated Air Use Management.

The IMPROVE program implemented an extensive long-term monitoring program to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the national parks and wilderness areas. The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups and air quality regulators to better understand and protect the visual air quality resource in Class I areas. IMPROVE documents the visual air quality in wilderness areas and national parks throughout the United States.

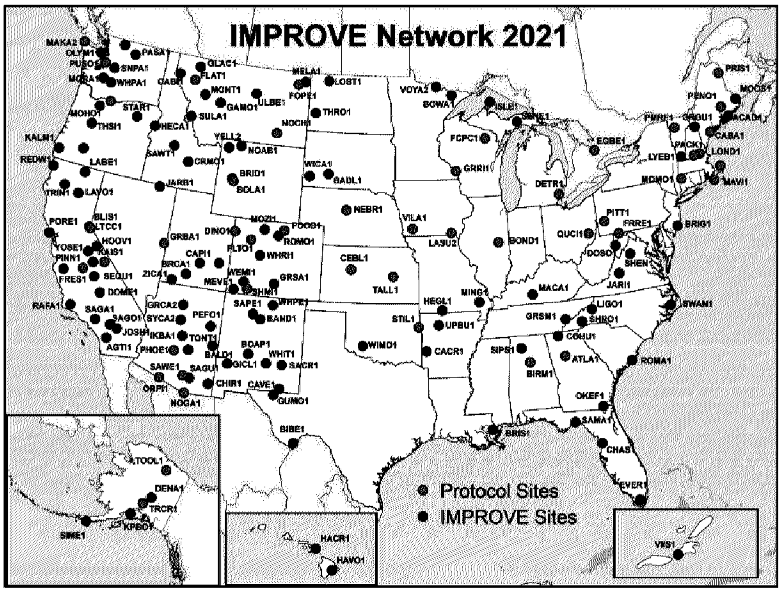
1.4.1.1 Overview of the IMPROVE Monitoring Network

The IMPROVE network focuses on rural areas in the western Unites States. Other visibility and aerosol monitoring networks, such as that of the National Weather Service Airport Visibility

Data, may focus on different air sheds and have different data collection objectives. In 1988, IMPROVE began with 20 monitoring sites. After publication of the regional haze rule in 1999, the first step in the implementation process was the upgrade and expansion of the IMPROVE network to 110 sites nationally. Figure 1-2 shows the IMPROVE monitoring network throughout the United States.

FIGURE 1-2

MAP OF IMPROVE MONITORING NETWORK IN THE UNITED STATES

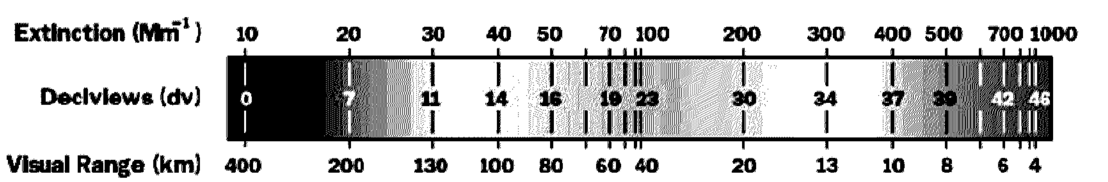


The IMPROVE network consists of aerosol and optical samplers. Every IMPROVE site deploys an aerosol sampler to measure speciated fine aerosols and coarse mass. Select sites also deploy a transmissometer and nephelometers to measure light extinction and scattering respectively, as well as automatic camera systems to visually measure the scene. Particulate concentration data are obtained every 24 hours and converted into reconstructed light extinction through a complex calculation using the IMPROVE algorithm which may be viewed at https://vista.cira.colostate.edu/Improve/the-improve-algorithm/. Light extinction, the impairment of visibility, occurs due to particles and gases that reflect and absorb light.

Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse megameters (1/Mm or Mm^{-1}). The RHR requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in the deciview unit (40 CFR 51.308(d)(2)). The relationship between light extinction in Mm^{-1}, Haze Index in dv and visual range in km is indicated by the scale in Figure 1-3.

FIGURE 1-3

LIGHT EXTINCTION-HAZE INDEX-VISUAL RANGE SCALE



Generally, a one dv change in the Haze Index is likely humanly perceptible under ideal conditions regardless of background visibility conditions. More information regarding tracking visibility conditions is found in USEPA's *Guidance for Tracking Progress Under the Regional Haze Rule* at: https://www.epa.gov/visibility/visibility-guidance-documents.

The IMPROVE data undergo extensive quality assurance and control procedures and analyses by its contractors and the National Park Service before it is released. The aerosol and optical data are made publicly available approximately nine months after collection. In addition, seasonal and annual data reports, special study data reports, technical publications and other data and analysis reports are prepared. IMPROVE program resources are available at: http://vista.cira.colostate.edu/Improve.

1.4.1.2 IMPROVE Monitor JARB1

Two operating IMPROVE monitoring sites are located in Nevada, one at Great Basin National Park and the other at the Jarbidge WA. The Walker River Paiute Tribe, a third monitoring site in Nevada, operated from June 2003 to November 2005. The IMPROVE monitor representing the air quality at the Jarbidge WA is identified as JARB1.

JARB1 was among the first 20 IMPROVE sites to start operation in 1988 and is sponsored by the U. S. Forest Service. Generally, JARB1 is expected to be representative of aerosol characteristics in the Jarbidge WA especially when the atmosphere is well mixed and regionally homogeneous. However, the site is at a low elevation in the Jarbidge River Canyon that is separate from the Jarbidge WA and upper East Fork of the Jarbidge River. Consequently, the monitoring site may at times be isolated from wilderness locations and potentially impacted by different local emission sources. Figure 1-2 shows the location of the JARB1 monitoring site by a red dot located along the northern border of Nevada.

As does every IMPROVE site, JARB1 deploys an aerosol sampler to measure speciated aerosols and coarse mass. Along with other selected sites, JARB1 also has an automatic camera system to obtain a visual record, a transmissometer to measure light extinction, and a nephelometer to measure light scattering. Data from these sampling devices are used to determine the visibility status at the Jarbidge WA.

1.4.2 Emissions Analyses and Projections

USEPA's RHR requires statewide emission inventories of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. Nevada's inventories are presented in Chapter Three. These emissions inventories are available from the WRAP TSS (http://views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx). The TSS webpage has links to many references that describe in detail the emissions methods used in developing the point, area, mobile, dust, offshore and fire emission inventories.

Emissions scenarios used in the development of this SIP represent actual baseline emissions (2014v2), representative baseline emissions (RepBase2), and projected emissions (2028OTBa2 and 2028PAC2). The baseline period includes 2014 through 2018, represented by 2014, while the projected inventories denote 2028 emissions, as discussed below. The projected inventories take into account growth, "on-the-books" controls and regulations and the application of regional haze strategies. The year 2028 was selected as it represents the final year for demonstrating reasonable progress during the second implementation period. These inventories were used for visibility and source apportionment modeling.

The pollutants examined are sulfur dioxide (SO_2), sulfur oxides (SO_X), nitrogen oxides (NO_X), volatile organic compound (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (PM fine or $PM_{2.5}$), coarse particulate (PM coarse or PM_{10}) and ammonia (NH_3). It is important to note that each of these pollutants have characteristics that differ in terms of ability to affect visibility. Assuming one emission unit of PM fine, for example, the same unit of SO_2 or NO_X would be about three times more effective at impairing visibility. Organic carbon is about four times more effective and elemental carbon about ten times more effective at impairing visibility. (Primary organic aerosols and elemental carbon are discussed in Chapter Four as part of the weighted emissions potential analysis.) Conversely, PM coarse is about half as effective as PM fine. Both VOC and NH_3 affect visibility only after certain chemical reactions occur and, therefore, cannot be compared in this manner.

1.4.2.1 Preparation of Baseline Emissions Inventories

2014 Base Case (2014v2) Inventory

The 2014v2 inventory used actual data reported by states, locals, tribes and USEPA databases, which evolved from states' actual emissions data submitted to USEPA for the 2014 National Emission Inventory. The WRAP RHPWG for Emissions Inventories and Modeling Protocol (RHPWG EI & MP)[1] contracted with Ramboll to improve upon the 2014 WRAP emissions inventory.[2] WRAP states replaced the 2014v2 NEI source sectors as listed below:

1. California Air Resources Board (CARB) provided emissions for all anthropogenic sectors in California.

[1] https://views.cira.colostate.edu/wiki/wiki/9191/western-us-regional-analysis-2014-neiv2-emissions-inventory-review-for-regi

[2] https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

2. WRAP states updated emissions for electric generating units (EGU), non-EGU point sources, and onroad mobile.
3. The WRAP Oil and Gas Workgroup (OGWG)[3] and its contractor Ramboll, Inc., defined a Roadmap for updating oil and gas inventories and delivered updated 2014 emissions (October 2018) for Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming (emissions for remaining WRAP states remain as in the EPA 2014v2 platform). [4]
4. The WRAP Fire and Smoke Work Group (FSWG) updated the 2014NEIv2 BlueSky/SmartFire emissions.[5]
5. Natural emissions were developed by WRAP for 2014v2 and held constant at 2014v2 levels for the Representative Baseline and future year scenarios.
6. All other WRAP emissions sectors and all Non-WRAP emissions for WRAP 2014v2 were based on the EPA 2014 modeling platform.[6]

TABLE 1-1

WRAP CAMx/PSAT DATA SOURCES

Source Sector	2014v2	RepBase2	2028OTBa2
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU [1]	WRAP-2028-EGU [1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]
Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

1. WRAP-RepBase2-EGU and WRAP-2028OTBa2-EGU include changes/corrections/updates from WESTAR-WRAP states
2. WRAP-RepBase2-O&G and WRAP-2028OTBa2-O&G both include corrections for WESTAR-WRAP states.
3. O&G for other WRAP states and Non-WRAP states use EPA-2016v1 assumptions for 2028OTBa2 and unit-level changes provided by WESTAR-WRAP states.
4. WRAP-2014v2 Non-EGU Point is used for RepBase2 and 2028OTBa2, with source specific updates provided by WESTAR-WRAP states.
5. WRAP-2028-MOBILE is used for On-Road and Non-Road sources for the 12WUS2 domain.
6. EPA-2016v1 and EPA-2028v1 are used for On-Road and Non-Road Mobile for the 36km US domain.
7. Non-Point emissions use 2014v2 emissions for RepBase2 and 2028OTBa2 scenarios, including state-provided corrections.
8. RepBase fires are used for both RepBase2 and 2028OTBa2

[3] http://www.wrapair2.org/ogwg.aspx
[4] http://www.wrapair2.org/pdf/OGWG_Roadmap_FinalPhase1Report_Workplan_13Apr2018.pdf
[5] http://www.wrapair2.org/fswg.aspx
[6] https://www.epa.gov/air-emissions-modeling/2014-version-71-platform

The purpose of the 2014v2 scenario is to represent the actual conditions in calendar year 2014 with respect to ambient air quality and the associated sources of visibility-impairing air pollutants. The 2014v2 emissions inventories were used to validate the air quality model and associated databases and to demonstrate acceptable model performance with respect to replicating observed particulate matter air quality for use in the Comprehensive Air Quality Model with Extensions (CAMx) model performance evaluations.

2014 through 2018 Representative Baseline-Period (RepBase2) Inventory

The Representative Baseline (RepBase2) emissions scenario updates the 2014v2 inventory to account for changes and variation in emissions between 2014 and 2018 for key WRAP source sectors, as defined by the WRAP Emissions and Modeling Protocol subcommittee. The RepBase2 inventory was delivered as listed below:

1. California Air Resources Board (CARB) used the same source sector emissions as defined for 2014v2.
2. The WRAP EGU Emissions Analysis Project[7] developed a comprehensive database for fossil fuel electric generating units in 13 continental western states, including operating characteristics and emissions, for the period circa 2014-2018. Methods are defined in Center for New Energy Economy's analysis of WRAP fossil-fueled Electric Generating Units for Regional Haze Planning and Ozone Transport Contribution[8] (June 2019.)
3. The WRAP Oil and Gas Workgroup and its contractor, Ramboll, Inc., developed the circa2014 baseline oil and gas inventory[9] to apply to the RepBase inventory.
4. The WRAP Fire and Smoke Work Group (FSWG) worked with states, tribes, federal land managers and Air Sciences, Inc., to define 2014 to 2018 wildfire emissions for the Continental U.S. (36-km modeling grid) to represent a broader range of fire conditions (Representative Fire) than the single year 2014, as reported in Fire Emissions Inventories for Regional Haze Planning: Methods and Results.[10]
5. All other emissions sectors used the EPA 2016v1 platform[11] for RepBase2.

During state review of the Representative Baseline emissions, some errors and duplicate records were identified. WRAP states revised select EGU, non-EGU point, and oil and gas emissions for a revised Representative Baseline (RepBase2). Data sources for RepBase2 emissions are defined in Table 1-1. WRAP methods are further defined in Ramboll Inc.'s Run Specification Sheet for Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulations.[12]

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[7] http://www.wrapair2.org/EGU.aspx
[8] https://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf
[9] http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf
[10] http://www.wrapair2.org/pdf/fswg_rhp_fire-ei_final_report_20200519_FINAL.PDF
[11] https://www.epa.gov/air-emissions-modeling/2016-version-1-technical-support-document
[12] https://views.cira.colostate.edu/iwdw/docs/WAQS_and_WRAP_Regional_Haze_spec_sheets.aspx

1.4.2.2 Projected 2028 Emissions Inventories

2028 On-the-Books (2028OTBa2) Inventory
The WRAP 2028OTBa emissions inventory projection followed the methods applied by EPA in the September 2019 Technical Support Document[13] for updated 2028 regional haze modeling. The WRAP states updated source sectors to account for implementation by 2028 of all applicable federal and state requirements for U.S. anthropogenic emissions as listed below:

1. California Air Resources Board (CARB) provided 2028OTB projections from 2014v2 for all anthropogenic source sectors.
2. WRAP states worked with western utilities and the Center for New Energy Economy to project EGU emissions for 2028 On the Books, as reported in WRAP EGU emissions for Representative Baseline and 2028 On the Books projections.[14]
3. The WRAP Oil and Gas workgroup and its contractor, Ramboll, Inc., projected 2028 Oil and Gas area and point source emissions for WRAP states as reported in Revised Final Report: 2028 Future Year Oil and Gas Emission Inventory for WESTAR-WRAP States, March 2020 version.[15]
4. WRAP 2028 CAMx-ready emissions for on-road and non-road mobile sources, including offshore shipping, rail and airports are reported in Mobile Source Emissions Inventory 2028 Projections Project.[16]
5. Wildfire, Wildland Prescribed fire, and agricultural fires for the 2028OTBa inventory were identical to RepBase fires.

In September 2020, the WRAP states made revisions to select EGU, non-EGU, and oil and gas emissions for the WRAP states in the updated 2028OTBa2 projection. EPA 2016v1 emissions were assigned to some source sectors for WRAP, non-WRAP, Canada and Mexico in lieu of EPA 2028v1 emissions to provide more conservative assumptions for the 2028OTBa2 projection.

2028 Potential Additional Controls (PAC2) Inventory
Some, but not all, western states made various enhancements beyond the 2028OTBa inventory to represent Potential Additional Controls resulting from the four-factor analyses conducted for the second implementation period to achieve reasonable progress. These updates reflected decreases in visibility impairing pollutants and were used to evaluate the potential visibility response in 2028. WESTAR-WRAP States and source sectors modified in the 2028 Potential Additional Controls (PAC2) modeling scenario compared to 2028OTBa2 are defined in Table 1-2.

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[13] https://www.epa.gov/sites/default/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf
[14] https://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf
[15] http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf
[16] http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project

TABLE 1-2

CHANGES TO 2028 PAC2 BY SOURCE SECTOR

2028PAC2 Changes to 2028OTBa2	EGU - Point	Non-EGU Point	Oil & Gas - Point	On-Road Mobile
Arizona (AZ)	X		X	
California (CA)				X
Colorado (CO)				
Idaho (ID)		X		
Montana (MT)	X			
Nevada (NV)	X	X		
New Mexico (NM)	X	X	X	
North Dakota (ND)	X			
Oregon (OR)	X	X	X	
South Dakota (SD)				
Utah (UT)				
Washington (WA)	X			
Wyoming (WY)				

Adjustments for the PAC2 modeling inventory were submitted to reflect potential reductions from control technology considered in draft four-factor analyses conducted by Nevada sources. Reductions achieved in the PAC2 inventory were based on assumptions relevant to the information of the draft four-factor analyses and do not represent final control determinations resulting from finalized four-factor analyses. Because of this, NDEP is not relying on the outputs of this model scenario for analyses in this SIP. Instead of using projected 2028 visibility conditions at Jarbidge WA from this model as Reasonable Progress Goals (RPGs) for the second implementation period, NDEP has made post-modeling adjustments to the RPGs calculated using the 2028OTBa2 model. This is discussed further in Chapter Six.

1.4.2.3 WRAP's Technical Support System

The Western Regional Air Partnership and Western Air Quality Study (WRAP-WAQS) 2014 Regional Haze modeling platform[17] is the latest of a series of regional modeling efforts supporting western U.S. air quality planning and management. The WRAP technical analyses follow the Environmental Protection Agency's (EPA) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze[18] (November 2018) and the Technical Support Document for EPA's updated 2028 regional haze modeling[19] (September 2019). The analyses fulfill the objectives of the WRAP 2018-2019 Workplan[20] as updated and approved by

[17] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[18] https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf
[19] https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling
[20] http://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf

the WRAP Board on April 3, 2019 and have been collectively designed, implemented, and reviewed by the WRAP Technical Steering Committee and its workgroups and subcommittees.

The Western Regional Air Partnership (WRAP) Technical Support System (TSS)[21] hosts the visibility monitoring, emissions, and air quality modeling analyses that support the 15 western states in developing regional haze state implementation plans (SIPs). This reference document describes the WRAP emissions and modeling analyses and illustrates how the TSS products can be applied and interpreted to support the 2028 visibility progress demonstrations for western U.S. Class I areas.

1.4.3 Air Quality Modeling

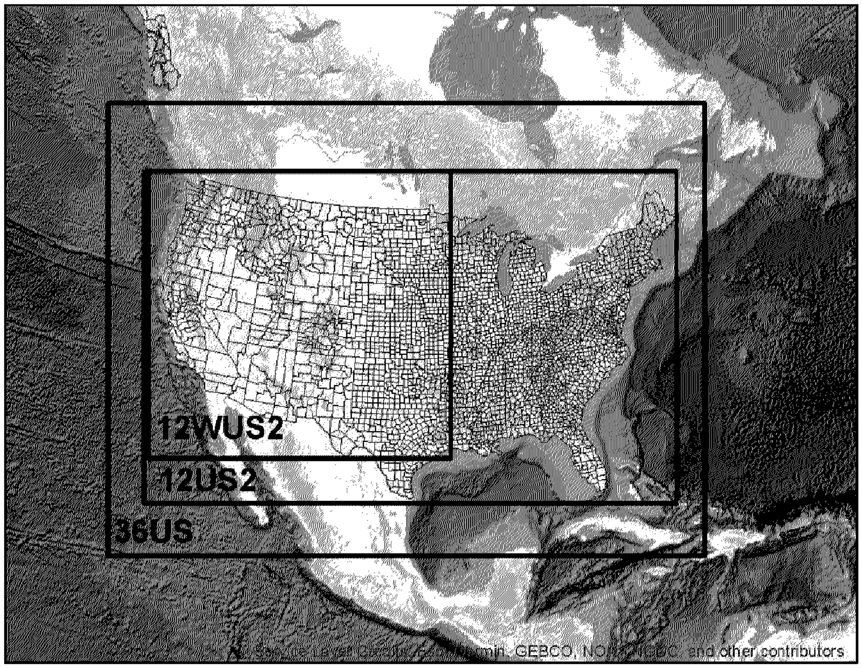
The sources of $PM_{2.5}$ are difficult to quantify because of the complex nature of their formation, transport and removal from the atmosphere. This makes it difficult to simply use emissions data to determine which pollutants should be controlled to most effectively improve visibility. Photochemical air quality models offer opportunity to better understand the sources of $PM_{2.5}$ by simulating the emissions of pollutants and the formation, transport and deposition of $PM_{2.5}$. If an air quality model performs well for an historical episode, the model may then be useful for identifying the sources of $PM_{2.5}$ and helping to select the most effective emissions reduction strategies for attaining visibility goals. Although several types of air quality modeling systems are available, the gridded, three-dimensional, Eulerian models provide the most complete spatial representation and the most comprehensive representation of processes affecting $PM_{2.5}$, especially for situations in which multiple pollutant sources interact to form $PM_{2.5}$.

The WRAP-WAQS 2014 modeling platform was developed and performed by Ramboll, Inc., under contract to WESTAR-WRAP. The 2014 modeling platform used the Weather Research and Forecasting (WRF) meteorological model, the Sparse Matrix Operator Kerner Emissions (SMOKE) model and the Comprehensive Air Quality Model with Extensions (CAMx) to project air quality for the 2014 base year. The Goddard Earth Observing System global chemical model (GEOS-Chem) provided global boundary conditions for the regional CAMx model for the 2014 base year. The CAMx 2014v2 final model configuration is defined in the WRAPWAQS 2014 modeling platform webpage. CAMx version 7beta 6 was used for the 2014v2 model performance run, while CAMx version 7.0 was used for the subsequent model scenarios. Figure 1-4 below illustrates the CAMx 36-km modeling domain covering the Continental United States and the 12-km modeling domain covering the western states.

[21] https://views.cira.colostate.edu/tssv2/

FIGURE 1-4

WRAP-WAQS 2014 MODELING PLATFORM DOMAINS



Comprehensive Air Quality Model with Extensions
The CAMx model was initially developed by ENVIRON in the late 1990s as a nested-grid, gas-phase, Eulerian photochemical grid model. ENVIRON later revised CAMx to treat PM, visibility and air toxics.

In support of the WRAP regional haze air quality modeling efforts, Ramboll developed air quality modeling inputs including annual meteorology and emissions inventories for a 2014 actual emissions base case, a planning case to represent the 2014 through 2018 regional haze baseline period using averages for key emissions categories, and a 2028 on-the-books base case of projected emissions.

WRF is a next-generation mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs. WRF contains separate modules to compute different physical processes such as surface energy budgets and soil interactions, turbulence, cloud microphysics, and atmospheric radiation. Within WRF, the user has many options for selecting the different schemes for each type of physical process. There is a WRF Preprocessing System (WPS) that generates the initial and boundary conditions used by WRF, based on topographic datasets, land use information, and larger-scale atmospheric and oceanic models.

All emission inventories were developed using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories has undergone a number of revisions throughout the development process to arrive at the final versions used in the CAMx air quality modeling. The development of each of these emission scenarios is documented under the emissions inventory sections of the TSS. In addition to various sensitivities scenarios, the WRAP performed air quality model simulations for each of the emissions scenarios.

Boundary conditions specify the concentrations of gas and PM species at the four lateral boundaries of the model domain. Boundary conditions determine the amounts of gas and PM species that are transported into the model domain when winds flow is into the domain. Boundary conditions have a much larger effect on model simulations than do initial conditions. For some areas in the WRAP region and for clean conditions, the boundary conditions can be a substantial contributor to visibility impairment.

For this study boundary conditions data generated in an annual simulation of the global-scale GEOS-Chem model for calendar year 2014 were applied. Additional data processing of the GEOS-Chem data was required before using them in CAMx. The data first had to be mapped to the boundaries of the WRAP domain, and the gas and PM species had to be remapped to a set of species used in the CAMx model.

1.4.3.1 Visibility Modeling

The RHR goals include achieving natural visibility conditions at 156 federally mandated Class I areas by 2064. In more specific terms, that goal is defined as visibility improvement toward natural conditions for the 20 percent of days that have the most anthropogenically impaired visibility conditions (termed "20 percent most-impaired" visibility days), and no worsening in visibility for the 20 percent of days that have the clearest visibility ("20 percent clearest" visibility days). One component of the states' demonstration to USEPA that they are making reasonable progress toward this 2064 goal during the second implementation period is the comparison of modeled visibility projections for 2028 with what is termed a uniform rate of progress (URP) from baseline to natural conditions by 2064.

Preliminary 2028 visibility projections have been made using the 2028OTBa2 and PAC2 CAMx 36-km and 12-km modeling results, following USEPA guidance that recommends applying the modeling results in a relative sense to project future-year visibility conditions (U.S. EPA, 2001, 2003a, 2006). Projections are made using relative response factors (RRFs), which are defined as the ratio of the future-year modeling results to the current-year modeling results. The calculated RRFs are applied to the baseline observed visibility conditions to project future-year observed visibility. These projections can then be used to assess the effectiveness of the simulated emission control strategies that were included in the future-year modeling. The major features of USEPA's recommended visibility projections are as follows (U.S. EPA, 2003a,b, 2006):

- Monitoring data should be used to define current air quality.
- Monitored concentrations of PM_{10} are divided into six major components; the first five are assumed to be $PM_{2.5}$ and the sixth is $PM_{2.5-10}$.
    - SO_4 (sulfate)
    - NO_3 (particulate nitrate)
    - OC (organic carbon)
    - EC (elemental carbon)
    - OF (other fine particulate or soil)
    - CM (coarse matter).

- Models are used in a relative sense to develop RRFs between future and current predicted concentrations of each component.
- Component-specific RRFs are multiplied by current monitored values to estimate future component concentrations.
- Estimates of future component concentrations are consolidated to provide an estimate of future air quality.
- Future estimated air quality is compared with the goal for regional haze to see whether the simulated control strategy would result in the goal being met.
- It is acceptable to assume that all measured sulfate is in the form of ammonium sulfate [$(NH_4)_2SO_4$] and all particulate nitrate is in the form of ammonium nitrate [NH_4NO_3].

RRFs calculated from modeling results can be used to project future-year visibility. For the current modeling efforts, RRFs are the ratio of the 2028 modeling results to the 2014 modeling results and are specific to each Class I area and each PM species. RRFs are applied to the Baseline Condition observed PM species levels to project future-year PM levels, which are then used with the IMPROVE extinction equation listed above to assess visibility.

For all of the western Class I areas, the WRAP performed preliminary 2028 visibility projections and compared them to the 2028 URP using the 2028OTBa2 and PAC2 CAMx modeling results and the old and new IMPROVE equations.

1.4.3.2 Source Apportionment Modeling

Impairment of visibility in Class I areas is caused by a combination of local air pollutants and regional pollutants that are transported long distances. To develop effective visibility improvement strategies, the WRAP member states and tribes need to know the relative contributions of local and transported pollutants, and which emissions sources are significant contributors to visibility impairment at a given Class I area.

A variety of modeling and data analysis methods can be used to perform source apportionment of the PM observed at a given receptor site. One method is to implement a mass-tracking algorithm in the air quality model to explicitly track for a given emissions source the chemical transformations, transport and removal of the PM that was formed from that source. Mass-tracking methods have been implemented in the CAMx air quality model as PSAT.

Source apportionment for regional haze planning was conducted using various modeling techniques. The SO_X/NO_X Tracer and Organic Aerosol Tracer were performed using the regional PSAT air quality model. The WEP analysis included the synthesis of emissions data and meteorological back trajectories. The PMF Receptor Modeling and Causes of Dust analysis were complex statistical exercises involving IMPROVE monitoring data. Not all source apportionment techniques were applied to all pollutants.

Particulate Source Apportionment Technology

The main objective of applying CAMx/PSAT is to evaluate the regional haze air quality for conditions typical of the 2014 through 2018 representative baseline period (RepBase2) and future-year 2028 (2028OTBa2) conditions. These results are used:

- To assess the contributions of different geographic source regions (e.g., states) and source categories to current (2014-2018) and future (2028) visibility impairment at Class I areas, in order to obtain improved understanding of the causes of the impairment and which states are included in the area of influence of a given Class I area.
- To determine which source categories contributing to the area of influence for each Class I area are changing, and by how much, between the 2014 through 2018 and 2028 base cases. by varying only controllable anthropogenic emissions between the 2 PSAT simulations; and
- To identify the source regions and emissions categories that, if controlled to lower emissions rates than the 2028 base case levels, would produce the greatest visibility improvements at a Class I area.

The PSAT performs source apportionment based on user-defined source groups. A source group is the combination of a geographic source region and an emissions source category. Examples of source regions include states, nonattainment areas and counties. Examples of source categories include mobile sources, biogenic sources and elevated point sources; PSAT can even focus on individual sources. The user defines a geographic source region map to specify the source regions of interest. He or she then inputs each source category as separate, gridded low-level emissions and/or elevated-point-source emissions. The model then determines each source group by overlaying the source categories on the source region map. PM source apportionment modeling was performed for aerosol SO_4 and aerosol NO_3 and their related species (e.g., SO_2, NO, NO_2, HNO_3, NH_3, and NH_4).

The source apportionment model results are typically presented in two ways:

- *Spatial plots* showing the area of influence of a source group's PM species contributions throughout the model domain, either at a given hourly-average point in time or averaged over some time interval (e.g., monthly average).
- *Receptor bar plots* showing the rank order of source groupings that contribute to PM species at any given receptor site. These plots also can be at a particular point in time or averaged over selected time intervals—for example, the average source contributions for the 20 percent worst visibility days.

The primary products of the WRAP PSAT modeling were receptor bar plots showing the emission source groups that contribute the most to the model grid cells containing each IMPROVE monitoring site and other receptor sites identified by WRAP.

Two annual 36-km CAMx/PSAT model simulations were performed: one with the RepBase representative baseline case and the other with the 2028OTBa2 future-year case. It is expected that the states and tribes will use these results to assess the sources that contribute to visibility impairment at each Class I Area and to guide the choice of emission control strategies. The TSS web site includes a full set of source apportionment spatial plots and receptor bar plots for both RepBase2 and 2028OTBa2. These graphical displays of the PSAT results, as well as additional analyses of these results are available on the TSS under http://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx.

Additional information related to the CAMx air quality model and PSAT apportionment algorithm can be found at https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf.

Weighted Emissions Potential

The WEP was developed as a screening tool for states to decide which source regions have the potential to contribute to haze formation at specific Class I areas, based on both the 2002 and 2018 emissions inventories. This method does not produce highly accurate results because, unlike the air quality model and associated PSAT analysis, it does not account for chemistry and removal processes. Instead, it relies on an integration of gridded emissions data, back trajectory residence time data, a one-over-distance factor to approximate deposition and a normalization of the final results. Residence time over an area is indicative of general flow patterns, but does not necessarily imply the area contributed significantly to haze at a given receptor. Therefore, users are cautioned to view the WEP as one piece of a larger, more comprehensive weight of evidence analysis.

The emissions data used were the annual, 36km grid SMOKE-processed, model-ready emissions inventories provided by the WRAP. The analysis was performed for nine pollutants (maps were generated for all but the last three):

- Sulfur oxides
- Nitrogen oxides
- Organic carbon
- Elemental carbon
- Carbon monoxide
- Fine particulate matter
- Coarse particulate matter
- Ammonia
- Volatile organic carbon

The following source categories for each pollutant were identified and preserved through the analysis:

- Biogenic
- Natural fire
- Point
- Area
- WRAP oil and gas
- Off-shore
- On-road mobile
- Off-road mobile
- Road dust
- Fugitive dust
- Windblown dust
- Anthropogenic fires.

The back trajectory residence times were provided by the WRAP. The project used NOAA's HYSPLIT model to generate eight back trajectories daily for each WRAP Class I area for the entire five-year baseline period (2014 through 2018). From these individual trajectories, residence time fields were generated for one-degree latitude by one-degree longitude grid cells. Residence time analysis computes the amount of time (e.g., number of hours) or percent of time an air parcel is in a horizontal grid cell. Plotted on a map, residence time is shown as percent of total hours in each grid cell across the domain, thus allowing an interpretation of general air flow patterns for a given Class I area. The residence time fields for the 20 percent most impaired and clearest IMPROVE-monitored extinction days were selected for the WEP analysis to highlight the potential emissions sources during those specific periods.

The WEP analysis consisted of weighting the annual gridded emissions (by pollutant and source category) by the most impaired and clearest extinction days residence times for the five-year baseline period. To account for deposition along the trajectories, the result was further weighted by a one-over-distance factor, measured as the distance in km between the centroid of each emissions grid cell and the centroid of the grid cell containing the Class I area monitoring site under investigation. (The "home" grid cell of the monitoring site was weighted by one fourth of the 36km grid cell distance, or one-over-9km, to avoid a large response in that grid cell.) The resulting weighted emissions field was normalized by the highest grid cell to ease interpretation.

The WEP is not a rigorous, stand-alone analysis, but a simple, straightforward use of existing data. As such, there are several caveats to keep in mind when using WEP results as part of a comprehensive weight of evidence analysis:

- This analysis does not take into account any emissions chemistry.
- While actual emissions may vary considerably throughout the year, this analysis pairs up annual emissions data with 20 percent most impaired/clearest extinction days residence times – this is likely most problematic for carbon and dust emissions, which can be highly episodic.
- Coarse particle and some fine particle dust emissions tend not to be transported long distances due to their large mass.
- The WEP results are unitless numbers, normalized to the largest-valued grid cell. Effective use of these results requires an understanding of actual emissions values and their relative contribution to haze at a given Class I area.

Additional information regarding WEP analysis can be found at https://views.cira.colostate.edu/tssv2/WEP-AOI/.

1.5 REFERENCES

U.S. EPA 2003. Guidance for Tracking Progress under the Regional Haze Rule. EPA-454/B-03-004. September 2003.

U.S. EPA 2013. General Principles for 5-year Regional Haze Progress Reports. April 2013.

U.S. EPA 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010. December 2018.

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2019. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling. September 2019.

U.S. EPA 2020. Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. June 2020.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Chapter Five – Four-Factor Control Determinations

5.1 OVERVIEW OF THE FOUR-FACTOR ANALYSIS PROCESS

40 CFR 51.308(f)(2)(i) focuses on the control analyses needed to determine what emission reduction measures will be necessary to make reasonable progress in each state's Long-Term Strategy. States are required to select sources for analysis of control measures, identify emission control measures to be considered for these sources, and evaluate potential controls based on the four statutory factors: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life.

States are required to evaluate major and minor stationary sources or groups of sources, mobile sources, and area sources. NDEP considered evaluating all groups but determined that more reductions would be achieved from major stationary sources and that any control analyses on minor sources would reasonably determine no controls as cost-effective. Area sources that may be contributing to visibility impairment at Nevada's Class I area were evaluated and it was concluded that most area source emissions were due to fugitive dust, however, no potential controls that could reasonably be implemented and enforced under the agency's local authority were identified. NDEP is depending on current and future federal/state regulations applicable to mobile sources to achieve reductions in that sector.

40 CFR 51.308(f)(2)(iii) requires that states document the technical basis, including cost, engineering, and emissions information, on which the state is relying to determine the emission reduction measures that are necessary to make reasonable progress. This chapter describes the selection of sources to conduct a four-factor analysis, NDEP's coordination with sources and other agencies in developing the four-factor analyses, and the final control determination for each source, including control requirements needed for the Long-Term Strategy.

5.2 SOURCE SCREENING IN NEVADA

NDEP and the air quality agencies of the WRAP used the Q/d method in identifying sources that are reasonably contributing to visibility impairment at any Class I area. Although not as sophisticated as modeling, this surrogate for source visibility impacts is significantly less resource intensive, while still providing a reliable method in determining which in-state sources should conduct a four-factor analysis.

Q/d represents a source's annual emissions in tons (Q) divided by the distance in kilometers (d) between the source and the nearest Class I area. For regional haze purposes, only primary visibility-impairing pollutants were included in a source's total Q: NO_X, SO_2, and PM_{10}. Emissions used to calculate a source's total Q were taken from the 2014v2 NEI. All sources, and their respective total Q, were inventoried and ranked by largest total Q to least. A Q/d threshold of 5 was set, identifying 8 sources that contributed to approximately 77% of statewide total NO_X, SO_2, and PM_{10} emissions. Table 5-1 outlines the sources identified by the Q/d analysis listed in order of potential visibility impacts based on the Q/d value. Aside from the Reid Gardner Station and McCarran International Airport, additional Q/d values are provided in Table 5-1 for the second and third closest Class I areas. These sources provide geographic representation of the three primary industrial areas in the state: the greater Reno area, the Las Vegas area, and the Interstate 80 industrialized corridor. Having sources from a broad geographic cross section of the state provides confidence that the selected stationary sources include those most likely to impair visibility at Class I areas both in Nevada and in neighboring states.

TABLE 5-1

SOURCES IDENTIFIED BY Q/D ANALYSIS TO CONDUCT
A FOUR-FACTOR ANALYSIS

Nearest Class I areas	CIA State	Total Q (tpy)	Distance to CIA (km)	Q/d	Percent of Statewide Q	Running Total of Percent of Statewide Q
Reid Gardner Station Power Plant						
Grand Canyon NP	AZ	6,944	84	**82.56**	19.8%	19.8%
North Valmy Generating Station						
Jarbidge Wilderness Area	NV	12,173	162	**75.10**	34.6%	54.4%
South Warner Wilderness	CA		255	47.74		
Mokelumne Wilderness	CA		330	36.89		
McCarran International Airport						
Grand Canyon NP	AZ	2,770	107	**25.97**	7.9%	62.3%
Lhoist North America Apex Plant						
Grand Canyon NP	AZ	1,662	88	**18.84**	4.7%	67.0%
Zion NP	UT		195	8.52		
Bryce Canyon NP	UT		277	6.00		
Nevada Cement Fernley Plant						
Desolation Wilderness	CA	1,482	102	**14.55**	4.2%	71.2%
Mokelumne Wilderness	CA		136	10.90		
Emigrant Wilderness	CA		180	8.23		
Tracy Generating Station						
Desolation Wilderness	CA	683	82	**8.33**	1.9%	73.1%
Mokelumne Wilderness	CA		122	5.60		
Emigrant Wilderness	CA		167	4.09		
TS Power Plant						
Jarbidge Wilderness Area	NV	834	131	**6.39**	2.4%	75.5%
South Warner Wilderness	CA		309	2.70		
Craters of the Moon NM	ID		362	2.30		
Graymont Pilot Peak Plant						
Jarbidge Wilderness Area	NV	673	131	**5.13**	1.9%	77.4%
Craters of the Moon NM	ID		263	2.56		
Sawtooth Wilderness	ID		297	2.27		

Of the sources listed above, three were considered and later removed from the four-factor analysis requirement. Reid Gardner Station Power Plant was identified using emissions data from the 2014v2 NEI, however, the entire facility ceased operation and was decommissioned in 2017 and has now been completely dismantled.

McCarran International Airport, now named the Harry Reid International Airport, was removed from the four-factor requirement as the vast majority of emissions are due to aircraft takeoffs, landings and ground movement, falling outside of the local air agencies' scope of authority. Table 5-2 lists the facility-wide allowable emissions for NO_X, SO_2, and PM_{10} at McCarran Airport that are listed in the Clark County Department of Environment and Sustainability (CCDES) air quality operating permit. Isolating only the maximum allowable, or controllable, emissions within the permit, a new Q/d of 1.35 is calculated for McCarran Airport, well below NDEP's Q/d threshold of 5.

TABLE 5-2

MCCARRAN AIRPORT CONTROLLABLE EMISSIONS
AND NEW Q/D

Facility	Nearest CIA	Distance to CIA (km)	Facility-Wide Permitted Allowable Emissions (tpy)			New Total Q	New Q/d
			NO_X	SO_2	PM_{10}		
McCarran Int'l Airport	Grand Canyon NP	88	87.95	2.35	28.82	119.12	1.35

5.3 NEVADA FOUR-FACTOR APPROACH

Each source that was identified in the source selection step elected to submit their own four-factor analyses to evaluate existing controls and consider potential additional control measures that may be necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada. NDEP has reviewed, and in some cases revised, the information and data used in the facility's four-factor analyses to ensure the method of evaluating control measures necessary to achieve reasonable progress agrees with the Regional Haze Rule regulatory language, USEPA Final Guidance for the second implementation period of the Regional Haze Rule, USEPA Clarifications Memo, and USEPA Control Cost Manual. In the event that no additional control measures are necessary to make reasonable progress at a source, NDEP evaluated whether existing control measures implemented at the source are necessary to make reasonable progress.

For the majority of the sources, NDEP requested additional information that is supplemental to the initial four-factor analyses submitted by sources, resulting in multiple response letters from the sources to bolster the information and data assumed in the four-factor analysis. NDEP has conducted "Reasonable Progress Control Determinations" that outlines the information assumed in considering control measures necessary for reasonable progress (considering the four statutory factors), and specifies what information was manipulated by NDEP to ensure each source's four-factor analysis meets applicable requirements.

All documentation needed to evaluate the legality and reasonableness of Nevada's reasonable progress conclusions are provided in Appendix B. Each sub-appendix under Appendix B pertains to one source, beginning with NDEP's "Reasonable Progress Control Determination" for the source, followed by the four-factor analysis submitted by the source, and any subsequent response letters. Table 5-3 below outlines Appendix B and where four-factor analysis documents can be located.

TABLE 5-3

LOCATION OF FOUR-FACTOR ANALYSES

Facility	Appendix Location of Four-Factor Analysis Documents
Apex Plant, Lhoist North America	B.1
Pilot Peak Plant, Graymont Western	B.2
TS Power Plant, NNEI	B.3
Fernley Plant, Nevada Cement Company	B.4
Tracy Generating Station, NV Energy	B.5
Valmy Generating Station, NV Energy	B.6

An emissions baseline for each unit evaluated in a four-factor analysis consists of emissions reported in a recent and relevant historical period. An emissions baseline derived from the average emissions of a time frame within 2014 and 2019 was selected by sources to reflect normal operations that is expected to continue through the remainder of the implementation period. If recent emissions varied, years with higher reported emissions were incorporated into the baseline to support a conservative analysis, unless verifiable documentation was provided to confirm that lower emissions will continue and not increase in future years.

Sources required to conduct a four-factor analysis included two EGUs, two lime production plants, and one cement production plant. Typically, these types of facilities, or units, evaluated similar suites of feasible control measures. Although source screening considered emissions reported for NO_X, SO_2, and PM_{10}, most analyses primarily focus on control measures for NO_X and SO_2 emissions, as all sources currently operate PM_{10} controls achieving at least 90% removal efficiency. Table 5-4 outlines the feasible add-on control measures considered. Operational and maintenance improvements were also considered.

TABLE 5-4

ADD-ON NO_x AND SO_2 CONTROLS CONSIDERED IN
FOUR-FACTOR ANALYSES

NO_x Control Measures	SO_2 Control Measures
Selective Non-Catalytic Reduction (SNCR)	Limestone/Lime-Based Flue Gas Desulfurization (FGD)
Selective Catalytic Reduction (SCR)	Dry Sorbent Injection (DSI)
Low NO_x Burners (LNB)	Alternative Low Sulfur Fuels
Dry Low NO_x Combustor	Wet Scrubbing
Over Fired Air (OFA)	Semi-Wet/Dry Scrubbing

All four statutory factors were evaluated and considered in control decisions for reasonable progress. Energy and non-air quality impacts and remaining useful life were considered as separate factors, but typically contributed to adjustments to the cost of compliance. Adverse energy and non-air quality impacts and a short remaining useful life were not used to preclude selection of an otherwise cost-effective control, rather these were considerations that inflated costs. Time necessary for compliance was used to determine a compliance date for controls selected for reasonable progress.

NDEP is relying on a cost-effectiveness ($/ton reduced) threshold of $10,000/ton when considering potential new control measures during the second implementation period. Compared to the BART threshold used during the first implementation period of $5,000/ton, the new threshold for reasonable progress controls is double. This is to ensure that the entire fleet of potential new control measures throughout Nevada are thoroughly considered, as well as, to ensure that enough controls are implemented during the second period to continue achieving reasonable progress at Jarbidge WA and other out-of-state CIAs.

As a result of the four-factor analyses, NDEP has determined the following control measures, listed in Table 5-5, as necessary to make reasonable progress during the second implementation period. Further discussion of the facilities, units, controls, and characterizations of the four statutory factors is provided in the following sections.

TABLE 5-5

CONTROL MEASURES NECESSARY TO MAKE REASONABLE PROGRESS

Facility	Unit	Control	Controlled Pollutant	Existing/New	Compliance Deadline
North Valmy Generating Station	Unit 1	Baghouse and Air Atomized Ignitors	PM_{10}	Existing	Upon SIP approval
		LNB+OFA	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2028
	Unit 2	Baghouse and Air Atomized Ignitors	PM_{10}	Existing	Upon SIP approval
		Spray Dryer with Lime Slurry	SO_2	Existing	Upon SIP approval
		LNB+OFA	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2028
Tracy Generating Station	Unit 5	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Unit 6	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Unit 7	Steam Injection	NO_x	Existing	Upon SIP approval
		Permanent Closure	-	New	December 31, 2031
	Unit 32	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval

	Unit 33	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval
Apex Plant	Kiln 1	LNB	NO_x	New	No later than two years after SIP approval
		SNCR	NO_x	New	
	Kiln 3	LNB	NO_x	Existing	
		SNCR	NO_x	New	
	Kiln 4	LNB	NO_x	Existing	
		SNCR	NO_x	New	
Pilot Peak Plant	Kiln 1	LNB	NO_x	Existing	240 days
	Kiln 2	LNB	NO_x	Existing	240 days
	Kiln 3	LNB	NO_x	Existing	240 days

5.4 SUMMARY OF FOUR-FACTOR CONTROL ANALYSES

A full control determination was completed for North Valmy and Tracy Generating Stations, Lhoist Apex and Graymont Pilot Peak lime production plants, and Nevada Cement Fernley cement production plant. A Reasonable Progress Determination was conducted for the TS Power Plant to evaluate potential controls. Emission limitations for reasonable progress were established on a case-by-case basis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, and the remaining useful life of the unit.

The control measures identified by Nevada as necessary to achieve reasonable progress will be installed and operating by a compliance deadline established through the consideration of the "time needed for compliance" statutory factor. Compliance schedules are determined on a case-by-case basis dependent on the type of control, planned outages at the facility, vendor availability, and other factors.

Facilities identified by Nevada's source screening procedure conducted their four-factor analyses internally, while coordinating with NDEP. In some cases, NDEP's review of the submitted four-factor analyses resulted in revisions to the original draft or requests were sent from NDEP to the facility to provide additional information. If the analysis and proposed control technologies were acceptable, NDEP relied on the submitted four-factor analyses to determine which controls are necessary to achieve reasonable progress. Where facility reasonable progress determinations were not accepted, the state made its own determinations using the facility reports as a foundation.

Each four-factor analysis established baseline emissions representative of actual emissions using acid rain data or actual annual emissions reported by each facility. Typically, sources used an annual average baseline comprised of emissions reported to NDEP during the 2016 through 2018 reporting years. All technically feasible controls that were considered for each unit at each facility assume achievable control efficiencies that were confirmed by NDEP. If a control was determined necessary to achieve reasonable progress, the assumed control efficiency was used to derive a new emission limit specific to the controlled pollutant on a case-by-case basis, along with corresponding averaging periods, and monitoring, record keeping, and reporting requirements.

A comparison of the baseline and post-control annual emissions resulting from the outcomes of the four-factor analyses and WRAP emissions inventories are presented for each facility below. The WRAP 2028 On-The-Books (2028OTBa2) emission inventory utilized 2014 NEIv2 emissions, with some adjustments made by states and on-the-books controls set to operate by the end of the period in 2028. Since the 2028OTBa2 modeling output does not include all new controls proposed in this SIP, new RPGs reflecting final reductions achieved through reasonable progress controls are derived in the next chapter.

5.5 NORTH VALMY GENERATING STATION FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at North Valmy Generating Station are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for North Valmy found in Appendix B.6.a. North Valmy's air quality operating permit is incorporated by reference into this SIP in Appendix A.6.

Note, that NV Energy submitted a four-factor analysis, and subsequent response letters to requests for additional information, for North Valmy and Tracy Generating Stations within the same files. Therefore, NDEP's "Reasonable Progress Control Determination" for North Valmy Generating Station is found in Appendix B.6, but references documents located in Appendix B.5 (sub-appendix for Tracy Generating Station). Table 5-6 outlines the files referenced in making reasonable progress determinations for North Valmy Generating Station, and where they can be found in Appendix B.

TABLE 5-6

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR VALMY

Full Document Title	Shortened Document Title	Date	Appendix Location
North Valmy Generating Station Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.6.a
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i
RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	B.5.k
Class I Air Quality Operating Permit	Permit		A.6

5.5.1 Baseline Emissions

For the purpose of NV Energy's four-factor analysis for the North Valmy Generating Station, baseline emissions were dervied from the annual average of emissions observed from 2016 through 2018. Table 5-7 shows the baseline emissions assumed for SO_2, NO_X, and PM_{10} emissions at Unit 1 and 2.

TABLE 5-7

VALMY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS

	SO_2	NO_x	PM
Baseline Emission Rates for Unit 1			
2016	1,848 ton/yr	797 ton/yr	22.01 ton/yr
2017	1,232 ton/yr	587 ton/yr	16.27 ton/yr
2018	2,357 ton/yr	1,027 ton/yr	27.76 ton/yr
2016-2018 Annual Average	**1,812 ton/yr 0.760 lb/MMBtu**	**804 ton/yr 0.337 lb/MMBtu**	**22.01 ton/yr 0.0092 lb/MMBtu**
Baseline Emission Rates for Unit 2			
2016	431 ton/yr	839 ton/yr	54.84 ton/yr
2017	356 ton/yr	674 ton/yr	20.97 ton/yr
2018	716 ton/yr	1,493 ton/yr	37.19 ton/yr
2016-2018 Annual Average	**501 ton/yr 0.158 lb/MMBtu**	**1,002 ton/yr 0.317 lb/MMBtu**	**37.67 ton/yr 0.0119 lb/MMBtu**

5.5.2 Identification of Technically Feasible Controls

For Unit 1 at the North Valmy Generating Station, NV Energy identified SCR and SNCR as technically feasible control measures in controlling NO_X emissions, and identified FGD and DSI using Milled Trona as technically feasible control measures in controlling SO_2 emissions. Additional PM_{10} control measures were not evaluated as Unit 1 already implements baghouses and air atomized ignitors to control particulate emissions, representing an existing effective control.

For Unit 2 at the North Valmy Generating Station, NV Energy identified SCR and SNCR as technically feasible control measures in controlling NO_X emissions, and identified upgrades to an existing lime slurry-based spray dryer as a technically feasible control measure in controlling SO_2 emissions. Additional PM_{10} control measures were not evaluated as Unit 2 already implements baghouses and air atomized ignitors to control particulate emissions, representing an existing effective control.

5.5.3 Characterization of Cost of Compliance

All potential new control measures outlined below assume a capital recovery factor of 0.2936, based on a 4-year equipment life (assuming controls go live beginning of 2025 and plant closes at the end of 2028) and an interest rate of 6.75%. A summary of the cost-effectiveness values for each technically feasible control technology considered at North Valmy Generating Station is provided in Table 5-8.

Utilizing the Control Cost Manual spreadsheet in evaluating SNCR as a potential control measure at both Valmy units, a cost-effectiveness value of $16,195/ton and $14,131/ton is estimated for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1. A total annual cost of implementing SNCR on Unit 1 is estimated at $3.2M and is projected to reduce

NO_X emissions by 200 tons per year. For Unit 2, the cost of implementing SNCR is estimated at $3.5M and is projected to reduce NO_X emissions by 250 tons per year.

Utilizing the Control Cost Manual spreadsheet in evaluating SCR as a potential control measure at both Valmy units, a cost-effectiveness value of $57,583/ton and $54,178/ton is estimated for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1.3 due to necessary modifications to the auxiliary power system, space constraints, new ductwork, and new steel and reinforcements. A total annual cost of implementing SCR on Unit 1 is estimated at $39M and is projected to reduce NO_X emissions by 681 tons per year. For Unit 2, the cost of implementing SCR is estimated at $45.5M and is projected to reduce NO_X emissions by 841 tons per year.

TABLE 5-8

VALMY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
SNCR	1	804 tpy NO_X	200 tpy NO_X	$3,235,852	$16,195 /ton
	2	1,002 tpy NO_X	250 tpy NO_X	$3,527,944	$14,100 /ton
SCR	1	804 tpy NO_X	681 tpy NO_X	$39.19 Million	$57,583 /ton
	2	1,002 tpy NO_X	841 tpy NO_X	$45.56 Million	$54,178 /ton
DSI w/ Milled Trona	1	1,812 tpy SO_2	1,338 tpy SO_2	$15.26 Million	$11,409 /ton
Limestone-Based FGD	1	1,812 tpy SO_2	1,751 tpy SO_2	$76.51 Million	$43,704 /ton
Lime-based FGD	1	1,812 tpy SO_2	1,751 tpy SO_2	$73.77 Million	$42,315 /ton
FGD Upgrade	2	2,278 tpy SO_2	365 tpy SO_2	$17.00 Million	$46,500 /ton

In evaluating the cost of compliance of replacing the existing DSI system using hydrated lime (designed to control HCl emissions) with a Trona-based Dry Sorbent Injection (Trona DSI) on Valmy Unit 1, the total annual cost of replacing the existing DSI system with a Trona-based DSI system is estimated at $15.26 million. This system is estimated to reduce annual SO2 emissions by 1,338 tons, or $11,409 per ton reduced.

The total annual cost of implementing a limestone-based flue gas desulfurization system is \$76.51 million, based on an estimated capital cost of \$247.8M. This system is estimated to reduce annual SO_2 emissions by 1,751 tons, or \$43,704 per ton reduced. The total annual cost of implementing a limestone-based flue gas desulfurization system is \$73.77 million, based on an estimated cost of \$238.2M. This system is estimated to reduce annual SO2 emissions by 1,751 tons, or \$42,135 per ton reduced.

5.5.4 Characterization of Time Necessary for Compliance

For NO_X controls, it is estimated that a minimum of 35 months would be needed to implement SNCR at both Valmy units. A minimum of six years is estimated to be needed to retrofit both Valmy units to implement SCR controls.

For SO_2 controls, it is estimated that a minimum of 34 months would d be needed to implement a DSI system using Milled Trona at Valmy Unit 1. Both FGD systems (limestone-based and lime-based) would require approximately six to eight years. At Valmy Unit 2, upgrading the existing FGD system by replacing the spray nozzles would require a minimum of 46 months before reaching compliance.

5.5.5 Characterization of Energy and Non-Air Quality Environmental Impacts

Both SCR and SNCR have the potential for ammonia slip if too much reagent is emitted unreacted. SCR will increase the parasitic load of the station and cause backpressure in the exhaust flow path.

All potential SO_2 controls would produce solid waste that would trigger EPA's CCR disposal rules. NVE estimates water losses over 61,000 gallons per day via evaporative losses that will occur when the hot boiler flue gas contacts the FGD reagent slurry. Electricity use would also increase in order to operate the system. All of these factors have been accounted for in the cost analysis. DSI systems have the potential to emit a yellow/brownish plume due to excess NO_X. Activated carbon injection is included in the cost analysis to mitigate this.

5.5.6 Characterization of Remaining Useful Life of the Source

As stated above, NVE has committed to shutting down and permanently ceasing operations at both units at North Valmy by December 31, 2028. This is reflected in annualized capital costs for SNCR and SCR.

Although NVE estimates various compliance schedules for each considered control ranging from 34 months up to eight years, NVE has conservatively estimated that all considered controls could be implemented by the end of 2024 when calculating the cost of compliance for both controls. Assuming all controls go on-line at the beginning of 2025 and both units permanently close at the end of 2028, a remaining useful life of 4 years is estimated.

5.5.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP concludes that no new control measures evaluated for the North Valmy Generating Station are necessary to make reasonable progress.

NDEP is relying on a federally enforceable and permanent closure date of December 31, 2028 for both units (used to reduce the remaining useful life of each unit and inflate cost-effectiveness values for all new control measures considered in the four-factor analysis) as necessary to achieve reasonable progress. During the time both units are in operation prior to closure, NDEP is also relying on the continued use of existing controls at Unit 1 (baghouse to control PM_{10} emissions and Low NO_x burners and over fired air to control NO_x emissions) and Unit 2 (baghouse to control PM_{10} emissions, Low NO_x burners and over fired air to control NO_x emissions, and spray dryer using a lime slurry to control SO_2 emissions) to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP (Table 5-9). These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The North Valmy Generating Station's permit, Permit No. AP4911-0457.03, can be found in Appendix A.6 of Nevada's second Regional Haze SIP.

TABLE 5-9

NORTH VALMY PERMIT CONDITIONS INCORPORATED BY REFERENCE

North Valmy Generating Station, Permit No. AP4911-0457.03		
	Citation	**Permit Condition**
Unit 1 (System 01 – Unit #1 Boiler)		
NO_x	VI.A.1.a.(3)	Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_x Burners and Over Fired Air.
	VI.A.2.e	The discharge of NOx (nitrogen oxides) to the atmosphere will not exceed **0.70** pound per million Btu, based on a 3-hour rolling average.
PM_{10}	VI.A.1.a.(1)-(2)	(1) Baghouse to control particulate matter emissions. (2) Air atomized ignitors to control particulate matter and opacity during startup and for flame stabilization
	VI.A.2.b	The discharge of PM (total particulate matter) to the atmosphere will not exceed **0.10** pound per million Btu.
	VI.A.4.a.1-3 VI.A.4.a.14	Compliance/Performance Testing
	VI.A.4.b.3 VI.A.4.b.7 VI.A.4.b.10	Monitoring
	VI.A.4.d.4-5 VI.A.4.d.7	Recordkeeping
	VI.A.4.e	Reporting
Unit 2 (System 02 – Unit #2 Boiler)		
NO_x	VI.B.1.a.(4)	Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_x Burners and Over Fired Air.
	VI.B.2.e	(1) 210 ng/J (**0.50 lb/million Btu**) heat input derived from combustion of Sub-bituminous coal; (2) 260 ng/J (**0.60 lb/million Btu**) heat input derived from the combustion of Bituminous coal;

		(3) 65 percent reduction of potential combustion concentration when combusting solid fuel
SO_2	VI.B.1.a.(2)	Spray dryer using a lime slurry with a rated **70%** minimum sulfur dioxide removal efficiency.
	VI.B.2.i	(1) 520 ng/J (**1.20 lb/million Btu**) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or (2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (**0.60 lb/million Btu**) heat input.
PM_{10}	VI.B.1.a.(1) VI.B.1.a.(3)	(1) Baghouse to control particulate matter emissions. (3) Air atomized ignitors to control particulates and opacity during startup and for flame stabilization
	VI.B.2.b	(1) 13 ng/J (**0.03 lb/million Btu**) heat input derived from the combustion of solid, liquid, or gaseous fuel; (2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; (3) and 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.
	VI.B.4.a.1-3 VI.B.4.a.14	Compliance/Performance Testing
	VI.B.4.b.3-4 VI.B.4.b.7 VI.B.4.b.9-10	Monitoring
	VI.B.4.d.4-7	Recordkeeping
	VI.B.4.e	Reporting
All Units Monitoring, Recordkeeping, and Reporting Requirements		
Section V.A - V.G		General Monitoring, Recordkeeping, and Reporting Requirements
Closure Date		
Section XI.C		As part of Nevada's Regional Haze State Implementation Plan's (SIP) Long-Term Strategy to achieve reasonable progress, the Permittee shall shutdown and permanently cease operation of **System 01 (S2.001)** and **System 02 (S2.002)** no later than December 31, 2028.

5.5.8 Discussion of North Valmy Generating Station Four-Factor Outcome

NV Energy has committed to cease operations and shutdown both electrical generating units at North Valmy Generating Station by December 31, 2028. With this closure date, no additional controls on either unit are cost-effective or necessary to achieve reasonable progress.

NV Energy's four-factor analysis relies on an emissions baseline derived from the annual average of emissions reported in 2016 through 2018. The emission reductions resulting from closure of both units are shown below in Table 5-10. By the end of 2028, or the end of the second implementation period, 1,746 tons per year of NO_x reductions, 2,313 tons per year SO_2 reductions, and 60 tons per year of PM_{10} reductions are expected from the closure of both Valmy units, amounting to a total of 4,119 tons per year reductions of visibility impairing pollutants.

WRAP emissions inventories underestimated the final reductions expected to be achieved at North Valmy Generating Station. Emissions reported by the Valmy Generating Station in 2016 were used to forecast Valmy's emissions in the 2028OTBa2 modeling emission inventory, or 2028 baseline before the implementation of potential controls. Beyond the 2028OTBa2 model, Valmy will reduce NO_x emissions by an additional 1,583 tpy and SO_2 emissions by an additional

2,281 tpy by the end of the second implementation period. New reasonable progress goals for 2028 are derived in Chapter 6 to account for these additional reductions.

TABLE 5-10

VALMY MODELING VS. FINAL EMISSION REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Unit 1					
NOx	785		796	0	796
SO2	1,850		1,812	0	1812
PM10	22		22	0	22
Unit 2					
NOx	798		950	0	950
SO2	431		501	0	501
PM10	55		38	0	38
Total NOx	1,583		1746	0	1746
Total SO2	2,281		2313	0	2313
Total PM10	77		60	0	60

Note: Negative values reflect annual emissions increases.

5.6 TRACY GENERATING STATION FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at the Tracy Generating Station are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for Tracy found in Appendix B.5.a. Tracy's air quality operating permit is incorporated by reference into this SIP in Appendix A.5. Table 5-11 outlines the files referenced in making reasonable progress determinations for the Tracy Generating Station, and where they can be found in Appendix B.

TABLE 5-11

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR TRACY

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Tracy Generating Station Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.5.a
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i
RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	B.5.k
Class I Air Quality Operating Permit	Permit		A.5

All major emission units currently in operation at the Tracy Generating Station that were considered in the facility's four-factor analysis are summarized in Table 5-12.

TABLE 5-12

LIST OF UNITS AT TRACY

NDEP Unit ID	NVE Unit ID	Description (and Nominal Rating)
Unit 3	Unit 3	Steam Boiler (MG) 113 MW
Unit 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Unit 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Unit 7	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)
Unit 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners
Unit 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners

Not all units at the Tracy Generating Station were required to be considered for potential new control measures. This was due to either low utilization, low emissions, or existing effective controls. Units 5 and 6 were screened out from further consideration of potential new control measures based on low utilization and low emissions. Units 32 and 33 were screened out from further consideration of potential new control measures based on existing effective controls and low emissions. Baseline emissions for Units 5, 6, 32, and 33 are provided in the following section.

Units 5 and 6 currently use Dry Low NO_X combustors to control NO_X emissions, and units 32 and 33 currently use Dry Low NO_X combustors and SCR to control NO_X emissions. NDEP considers the continued use of these existing controls as necessary to achieve reasonable progress.

Units 3 and 7 were evaluated for potential new control measures for NO_X emissions considering the four statutory factors. Potential new control measures for SO_2 and PM_{10} were not considered for any units at the Tracy Generating Station, as all units burn natural gas, resulting in low annual emissions for SO_2 and PM_{10}.

To comply with BART during the first round of Regional Haze in Nevada, Unit 3 discontinued the occasional use of distillate fuel and was retrofitted with the best available Low-NO_X Burners. NDEP does not consider these control measures to reduce NO_X, SO_2, and PM_{10} emissions as necessary to achieve reasonable progress as they are already incorporated into Nevada's Regional Haze SIP to satisfy BART.

Currently, the Unit 7 turbine uses steam injection to partially quench the heat of combustion to control NO_X emissions to approximately 41 ppm at 15% O_2 (2016-2018 average). NDEP considers the continued use of this control measure to control NO_X emissions as necessary to achieve reasonable progress.

5.6.1 Baseline Emissions

In NV Energy's initial four-factor analysis (*NVE Analysis* found in Appendix B.5.b) baseline emissions were derived from the annual average of emissions from 2016 through 2018. NDEP is relying on the 2016 through 2018 baseline emissions in evaluating Units 5, 6, 32, and 33, as annual emissions in 2018 were the most recent emissions data available at the time these units were screened out from a four-factor requirement. Table 5-13 outlines the baseline emission for units 5, 6, 32, and 33.

TABLE 5-13

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNITS 5, 6, 32, AND 33

Unit ID	Average NO_x Emissions (tpy)	Average SO_2 Emissions (tpy)	Average PM_{10} Emissions (tpy)
Unit 5	12.0	0.3	1.0
Unit 6	10.6	0.2	0.8
Unit 32	38.5	4.0	24.3
Unit 33	37.5	4.0	23.8

For the purpose of NV Energy's four-factor analysis for the Tracy Generating Station, baseline emissions were adjusted to reflect the annual average of emissions observed from 2016 through 2020. Emissions data for 2019 and 2020 were incorporated into the baseline emissions for Units 3 and 7 as they became available and were included in later Response Letters submitted by NV Energy. Tables 5-14 and 5-15 show the baseline emissions assumed for SO_2, NO_x, and PM_{10} emissions at Units 3 and 7.

TABLE 5-14

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNIT 3

	Unit 3 Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	77	61	114	230	210
2016-2018 Average	84				
2016-2020 Average	138				

TABLE 5-15

TRACY FOUR-FACTOR ANALYSIS BASELINE EMISSIONS FOR UNIT 7

	Unit 7 Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	190	182	269	315	293
2016-2018 Average	213				
2016-2020 Average	250				

5.6.2 Identification of Technically Feasible Controls

As described in NDEP's Reasonable Progress Determination for the Tracy Generating Station (*NDEP Tracy Determination)*, Units 5, 6, 32, and 33 were screened out from further consideration of additional control measures, since these units all have existing effective controls and low annual emissions, indicating that a four-factor analysis would not result in any cost-effective additional controls that would be necessary to achieve reasonable progress for the second implementation period.

For Unit 3 at the Tracy Generating Station, NV Energy identified SCR and SCNR as technically feasible control measures in controlling NO_X emissions.

For Unit 7 at the Tracy Generating Station, NV Energy identified SCR and Dry Low NO_X Combustors as technically feasible control measures in controlling NO_X emissions.

Since all units at the Tracy Generating Station are natural gas fired, potential additional SO_2 and PM_{10} control measures were not evaluated as the use of natural gas is considered as an existing effective control in controlling SO_2 and PM_{10} emissions. As seen in the above table for baseline emissions, SO_2 and PM_{10} emissions at all units are low, and would likely not result in a cost-effective add-on control for SO_2 and PM_{10} emissions that would be necessary to achieve reasonable progress if a four-factor analysis were conducted.

5.6.3 Characterization of Cost of Compliance

As shown in Table 5-16, all potential control measures evaluated for Units 3 and 7 yield a cost-effectiveness value above NDEP's threshold of $10,000 per ton of NO_X reduced. Cost information used to determine the total annualized costs of each control that NDEP is relying on can be found in the *NDEP Tracy Determination* and other supporting documentation found in Appendix B.5.

TABLE 5-16

TRACY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
Dry Low NO_X Combustor	7	250 tpy NO_X	157 tpy NO_X	$2,724,697	$17,355 /ton
SNCR	3	138 tpy NO_X	35 tpy NO_X	$474,641	$13,561 /ton
SCR	7	250 tpy NO_X	225 tpy NO_X	$2,259,408	$10,064 /ton
	3	138 tpy NO_X	124 tpy NO_X	$1,387,040	$11,186 /ton

5.6.4 Characterization of Time Necessary for Compliance

For controls considered for Unit 3, an estimated two to three years would be needed to fully implement SCR or SNCR. For Unit 7, 47 months would be needed to fully implement SCR and two years for implementation of Dry Low NO_X combustors. These timeframes include design, permitting, procurement, installation, startup, and schedules that support regional electrical needs during each unit's outage.

5.6.5 Characterization of Energy and Non-Air Quality Environmental Impacts

Both SNCR and SCR have the potential to produce "ammonia slip." Installation of SCR in the exhaust flow path of the boiler causes a backpressure which must be offset by increased electrical demand. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. An annual electricity cost of $48,551 in 2019 dollars is estimated in Appendix B of the "Tracy Generating Station Four Factor Analysis" within the *NVE Analysis*.

For the installation of a Dry Low NO_X Combustor, NVE states in the *NVE Analysis* that this control would have a negative impact on the plant's water balance and result in a wastewater stream that would require treatment or disposal. A DLN conversion would also decrease the electrical generation of the turbine because of the decreased mass flow. This would add an annual cost of $870,000 in energy purchases.

5.6.6 Characterization of Remaining Useful Life of the Source

There is currently no federally enforceable closure date of Unit 3 that would restrict the remaining useful life of the unit when considering annualized capital costs. Because of this, NDEP is relying on the recommended life of SNCR and SCR listed in the EPA Control Cost Manual of 20 years and 30 years, respectively.

NDEP is relying on a service life of at most only 6 years before permanent shutdown of the unit for SCR implementation. NDEP is relying on a 9-year life for a Dry Low NO_X Combustor on Unit 7 given that the control go online by the end of 2022 and the unit permanently ceases operation at the end of 2031.

5.6.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP concludes that no new control measures evaluated for the Tracy Generating Station are necessary to make reasonable progress.

NDEP is relying on a federally enforceable and permanent closure date of December 31, 2031 for Unit 7 (used to reduce the remaining useful life of the unit and inflate cost-effectiveness values for all new control measures considered for Unit 7 in the four-factor analysis) as necessary to achieve reasonable progress. During the time Unit 7 remains in operation prior to closure, NDEP is also relying on the continued use of existing controls (steam injection to control NO_X emissions) to make reasonable progress.

As stated above, NDEP is relying on the continued use of existing NO_X controls at Units 3, 5, 6, 32, and 33 to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP (Table 5-17). These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The Tracy Generating Station's permit, Permit No. AP4911-0194.04, can be found in Appendix A.5 of Nevada's second Regional Haze SIP.

TABLE 5-17

TRACY PERMIT CONDITIONS INCORPORATED BY REFERENCE

Tracy Generating Station, Permit No. AP4911-0194.04		
	Citation	**Permit Condition**
Unit 5 (System 05A – Clark Mountain Combustion Turbine #3)		
NO_x	IV.B.1.a	Emissions from **S2.006** shall be controlled by **Dry Low NOx Burners** while combusting natural gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **B.2.c.** of this section. Note, these are not add-on controls.
	IV.B.3.f	The discharge of **NOx** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period; (2) **42.0 pounds** per hour, based on a 720-hour rolling period; (3) **122.64** tons per year, based on a 12-month rolling period.
Unit 6 (System 06A – Clark Mountain Combustion Turbine #4)		
NO_x	IV.D.1.a	Emissions from **S2.007** shall be controlled by **Dry Low NOx Burners** while combusting Pipeline Natural Gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defied in **D.2.c.** of this section. Note, these are not add-on controls.
	IV.D.3.f	The discharge of **NOx** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period; (2) **42.0 pounds** per hour, based on a 720-hour rolling period; (3) **122.64** tons per year, based on a 12-month rolling period.
Unit 7 (System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine)		
NO_x	IV.F.1	a. Emissions from **S2.009** shall be controlled by a **Steam Injection** for control of NOx. b. Emissions from **S2.009.1** shall be controlled by **Dry Low NOx Burners**. Note, these are not add-on controls.
	IV.F.3.f	The discharge of **NOx** (oxides of nitrogen) to the atmosphere shall not exceed **141.0 pounds** per hour, nor more than **533.1 tons** per 12-month rolling period.
Unit 32 (System 32 – Combined Cycle Combustion Turbine Circuit No. 8)		
NO_x	IV.L.1.a	NOx emissions from **S2.064 and S2.065** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
	IV.L.3.g	The discharge of **NOx** to the atmosphere shall not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.
Unit 33 (System 33 – Combined Cycle Combustion Turbine Circuit No. 9)		
NO_x	IV.M.1.a	NOx emissions from **S2.066 and S2.067** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a

		volume specified by the manufacturer.
	IV.M.3.g	The discharge of **NO_X** to the atmosphere shall not exceed **2.00** parts per million (ppmv) by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.
All Units – Monitoring, Recordkeeping, Reporting		
	V.A & V.C	Oxides of Nitrogen (NO_x) Continuous Emissions Monitoring System (CEMS) Conditions
Closure Date		
VIII.A.		As part of Nevada's Regional Haze State Implementation Plan's (SIP) Long-Term Strategy to achieve reasonable progress, the Permittee shall shutdown and permanently cease operation of **System 07C (S2.009, S2.009.1)** no later than December 31, 2031.

5.6.8 Discussion of Tracy Generating Station Four-Factor Outcome

Upon conclusion of the initial four-factor analysis and after discussions with NDEP, NV Energy has since committed to NDEP to cease operations at Unit 7 Piñon Pine by December 31, 2031. This new closure date lowered the remaining useful life of the unit from 30 years to approximately 6 years, inflating the cost effectiveness value to $10,064/ton for SCR and $17,355/ton for Dry Low NO_x combustors. NDEP does not consider controls above $10,000/ton as cost-effective for the second implementation period of the Regional Haze Rule. Reductions from the closure of this unit will not be observed during the second implementation period, ending in 2028, but will be observed in Nevada's third implementation period of the Regional Haze Rule. Because of this, expected reductions cannot be quantified or assumed in Nevada's reasonable progress goals for the second implementation period.

In the 2028OTBa2 emission inventory, facility emissions for Tracy are taken from annual emissions reported in 2018. By the end of the second implementation period in 2028, final reductions achieved from the unit's closure will not be observed yet. To reflect this, NDEP expects no emission reductions at the Tracy Generating Station as a result of this round's four-factor analyses by the end of the planning period. An emissions summary is outlined in Table 5-15.

Although there is a slight difference in NO_x emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 5-18, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at Tracy.

TABLE 5-18

TRACY MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Unit 3 Steam Boiler					
NOx	114		84	84	0
SO2	1		1	1	0
PM10	2		2	2	0
Unit 4 Clark Mountain 3					
NOx	22		12	12	0
SO2	1		1	1	0
PM10	1		1	1	0
Unit 5 Clark Mountain 4					
NOx	20		11	11	0
SO2	1		1	1	0
PM10	1		1	1	0
Unit 6 Pinon Pine 4					
NOx	267		250	250	0
SO2	1		1	1	0
PM10	7		7	7	0
Unit 8					
NOx	40		39	39	0
SO2	4		4	4	0
PM10	24		24	24	0
Unit 9					
NOx	40		38	38	0
SO2	4		4	4	0
PM10	24		24	24	0
Total NOx	503		434	434	0
Total SO2	12		12	12	0
Total PM10	59		59	59	0

Aside from the closure of the Piñon Pine unit by December 31, 2031, Nevada is also relying on existing controls, listed in Table 5-19, that effectively control visibility impairing pollutants. The continued use of these existing controls will be included in Nevada's Long Term Strategy for the second implementation period, along with the current corresponding NO_X emission limits for each unit listed in the facility's current operating permit. These listed controls target NO_X emissions as the Tracy facility primarily burns pipeline natural gas.

TABLE 5-19

TRACY EXISTING CONTROLS FOR NO_X

Permit ID	NVE ID	Description and Nominal Rating	Current Control	Permitted NO_X Emission Limit
System 3	3	Steam Boiler (NG) 113 MW	Low-NO_X Burner	0.19 lb/MMBtu based on a 12-month rolling average
System 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_X combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_X combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 7	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)	steam injection	141.0 lb/hr, nor more than 533.10 tpy based on a 12 month rolling average
System 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NO_X combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average
System 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NO_X combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average

5.7 APEX PLANT FOUR-FACTOR OVERVIEW

For the purpose of determining whether controls at the Apex Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Apex Plant found in Appendix B.1.a. The Apex Plant's air quality operating permit is incorporated by reference into this SIP in Appendix A.1. Table 5-20 outlines the files referenced in making reasonable progress determinations for the Apex Plant, and where they can be found in Appendix B.

TABLE 5-20

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR APEX PLANT

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Apex Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	March 2022	B.1.a
Regional Haze Second Planning Period Four-Factor Analysis	*LNA Analysis*	March 24, 2021	B.1.b
RE: RHR Apex Plant Update	*LNA Email*	September 13, 2021	B.1.c
RE: Lhoist North America of Arizona, Inc. - Apex Plant Comments on Draft 2021 Regional Haze Four Factor Review and Initial Control Determination	*LNA Comments*	October 13, 2021	B.1.d
Class I Air Quality Operating Permit	Permit		A.1

5.7.1 Baseline Emissions

The Apex Plant is a lime production facility that operates four horizontal rotary preheater lime kilns. Baseline emissions assumed for each kiln for the purpose of conducting a four-factor analysis are provided in Table 5-21. The baseline emissions are derived from the annual average of emissions reported from 2016 to 2018.

TABLE 5-21

APEX PLANT FOUR-FACTOR ANALYSIS BASELINE EMISSIONS

Process Level	SO_2 Emissions (tpy)	NO_x Emissions (tpy)	PM_{10} Emissions (tpy)
Kiln 1	107.30	304	18.46
Kiln 2	5.32	19	1.12
Kiln 3	14.42	154	15.81
Kiln 4	8.21	687	23.04
Facility-Wide (Total)	135	1,164	58.43

5.7.2 Identification of Technically Feasible Control Measures

For all kilns at the Apex Plant, Lhoist North America identified LNB and SNCR as technically feasible control measures in controlling NO_X emissions. LNB is only considered for Kilns 1 and 2, as Kilns 3 and 4 already implement the control. SNCR is evaluated for all four kilns.

For Kilns 2 and 4 at the Apex Plant, Lhoist North America identified a fuel switch to use of natural gas only as a technically feasible control measure in controlling SO2 emissions. This was not considered for Kilns 1 and 3 since these kilns are intended to produce dolomitic lime, which cannot be produced using 100% natural gas. Kilns 2 and 4 are intended to produce HiCal lime, which can be produced using 100% natural gas.

Additional PM_{10} controls are not evaluated for the Apex Plant kilns, as PM_{10} emissions at all four kilns are already controlled by baghouses that meet the definition of best available control technology (BACT). Low annual baseline PM_{10} emissions confirm that all four kilns are effectively controlled by the existing baghouses.

5.7.3 Characterization of Cost of Compliance

Table 5-22 summarizes how the cost of compliance was characterized for each control measure considered in the facility's four-factor analysis using baseline emissions, assumed control efficiencies, total tons reduced, total annualized costs, and cost-effectiveness values (annual dollars per ton of pollutant reduced).

Cost-effectiveness values for the implementation of LNB and SNCR are focused on achievable NO_X reductions based on the baseline NO_X emissions and assumed control efficiency of each control. A 10% NO_X reduction is assumed for the implementation of LNBs. A 20% NO_X reduction at Kilns 1, 2, and 3, and a 50% NO_X reduction at Kiln 4, are assumed for the implementation of SNCR. The control efficiency of SNCR differs between Kiln 4 and the rest of the Apex Plant kilns due to differences in age and configuration (discussed further in Lhoist's four-factor analysis).

Although switching to 100% natural gas at Kilns 2 and 4 have the potential to reduce SO_2 and PM_{10} emissions, increased use of natural gas increases NO_X emissions. To ensure the change in all visibility impairing pollutants are considered, baseline emissions and tons reduced are calculated from the sum of NO_X, SO_2, and PM_{10} emissions. The assumed control efficiency is only applied to SO_2 emissions. For Kiln 4's case, the increase in NO_X emissions surpasses the reduced SO_2 and PM_{10} emissions, resulting in an overall increase in emissions (negative tons reduced value) that produces a negative cost-effectiveness value (marked N/A in table).

TABLE 5-22

APEX PLANT FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Kiln	Baseline Emissions (tpy)	Assumed Control Efficiency	Tons Reduced (tpy)	Total Annualized Costs	Cost – Effectiveness
LNB	1	304 tpy NO_X	10%	30.35 tpy NO_X	$25,792	$850 /ton
	2	19 tpy NO_X	10%	1.91 tpy NO_X	$25,792	$13,494 /ton
SNCR	1	304 tpy NO_X	20%	60.70 tpy NO_X	$164,394	$2,708 /ton
	2	19 tpy NO_X	20%	3.82 tpy NO_X	$144,681	$37,847 /ton
	3	154 tpy NO_X	20%	30.84 tpy NO_X	$154,044	$4,995 /ton
	4	687 tpy NO_X	50%	343.34 tpy NO_X	$262,344	$764 /ton
Fuel Switch to 100% NG	2	23.66 tpy NO_X, SO_2, and PM_{10}	99.92%	1.02 tpy NO_X, SO_2, and PM_{10}	$8,708,565	$8,666,204 /ton
	4	724.46 tpy NO_X, SO_2, and PM_{10}	99.62%	-147.92 tpy NO_X, SO_2, and PM_{10}.	$1,589,821	N/A

5.7.4 Characterization of Time Necessary for Compliance

Lhoist North America indicates that the time necessary for compliance of LNB and SNCR across all kilns would require two years, while a fuel-switch to 100% natural gas could be implemented at Kilns 2 and 4 by 2028, or approximately six years.

5.7.5 Characterization of Energy and Non-Air Quality Environmental Impacts

An expected decrease in efficiency throughout the facility as significant energy and water use is increased to support the SNCR technology is represented as additional power costs in the evaluation of cost of compliance. An additional annual power cost of $16,272 per kiln is estimated based on LNA's previous experience in implementing SNCR on Lhoist's Nelson facility. It is also acknowledged that the use of SNCR, and urea as a reagent, may introduce ammonia slip to the kilns. This is not accounted for in the cost calculations.

No energy and non-air quality impacts were identified when considering the implementation of Low-NO_X Burners or a fuel switch to 100% natural gas.

5.7.6 Characterization of Remaining Useful Life of the Source

Currently, there is no federally enforceable closure date for the Apex Plant. Because of this, the typical life of LNB and SNCR specified in the USEPA Control Cost Manual of 20 years is assumed. A 20-year life is also assumed for switching to 100% natural gas.

5.7.7 Decisions on what Control Measures are Necessary to Make Reasonable Progress

Based on the four statutory factors, NDEP considers the implementation of LNBs at Kiln 1, and implementation of SNCR at Kilns 1, 3, and 4 as necessary to achieve reasonable progress during the second implementation period of Nevada's Regional Haze SIP. As previously stated, LNBs have recently been installed on Kilns 3 and 4 that have not yet been incorporated into the Apex Plant's current air quality operating permit. NDEP considers the continued use of LNB on Kiln 3 and 4 as necessary to make reasonable progress as well. New NO_X emission limits (and other requirements) that reflect the use LNB and SNCR at Kilns 1, 3, and 4, are derived in the *NDEP Reasonable Progress Determination* for the Apex Plant, found in Appendix B.1.a. These new limits, and other associated requirements, were revised into the Apex Plant's air quality operating permit.

The following requirements are established in the Apex Plant's Authority to Construct Permit issued and enforced by the Clark County Department of Environment and Sustainability as enforceable permit conditions (Table 5-23). The referenced permit conditions below are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Apex Plant's Authority to Construct permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.1.

TABLE 5-23

APEX PLANT ATC PERMIT CONDITIONS INCORPORATED BY REFERENCE

Apex Plant, Authority to Construct Permit for a Major Part 70 Source, Source ID: 3, Clark County DES		
	Citation	Permit Condition
Control Requirements (Facility-Wide)		
NO_x	2.2.1	The control requirements and the NO_X emission reductions proposed in the ATC are permanent and shall not be removed, changed, revised, or modified without the approval of the Nevada Division of Environmental Protection and EPA upon becoming effective.
	2.2.2	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall install and maintain **low-NO_X burners (LNB) on Kilns 1, 3 and 4** in order to achieve a reduction of **NO_X emissions** (EU: K102, K302, and K402).
	2.2.3	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall install, operate, and maintain **selective non-catalytic reduction (SNCR) on Kilns 1, 3, and 4 (EUs: K102, K302, and K402) to achieve reduction of NO_X emissions**
Emission Limits (Facility-Wide)		
NO_x	3.2.1	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee shall **limit total NO_X emissions from all operating kilns to 3.75 tons per day based on a consecutive 30-day average** (EUs: K102, K202, K302, and K402).
	3.2.2	Effective no later than two years after the EPA's approval of the controls determination associated with the SIP, the permittee **shall limit the combined total NO_X emissions from all operating kilns to 3.59 lb/tlp based on a consecutive 12-month average** (EUs: K102, K202, K302, and K402)
Monitoring, Recordkeeping, and Reporting Requirements		
NO_x	4.1	Monitoring
	4.3.6 4.3.7	Recordkeeping
	4.4.7 4.4.8	Reporting and Notifications

5.7.8 Discussion of Apex Plant Four-Factor Outcome

For Kilns 1, 3, and 4, Low-NO_x Burners and Selective Non-Catalytic Reduction for NO_x control are necessary to achieve reasonable progress. Low NO_x Burners control fuel and air mixing at each burner to reduce peak flame temperature and reduce NO_x formation. Selective Non-Catalytic Reduction injects a reagent, typically urea or anhydrous gaseous ammonia, into the flue gas stream of a system to scrub NO_x emissions.

In the WRAP emission inventories, 2028OTBa2 used reported facility emissions from 2014 to forecast 2028 baseline emissions. Final reductions achieved from the four-factor analysis are greater than what was assumed in the WRAP emission inventories. A comparison of the

2028OTBa2 and final reductions resulting from reasonable progress controls is shown in Table 5-24.

Nevada expects additional NO_X reductions as a result of the four-factor analysis beyond what was assumed in the 2028OTBa2 modeling. The Apex Plant will reduce NO_X emissions by an additional 493 tpy by the end of the second implementation period. New reasonable progress goals for 2028 are derived in Chapter 6 to account for these additional reductions.

TABLE 5-24

APEX MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		**Four-Factor Analysis**		
	2028OTBa2 Emissions		**Baseline Emissions**	**Emissions after Controls**	**Emission Reductions**
Kiln 1					
NOx	294		304	219	85
SO2	107		107	107	0
PM10	2		19	19	0
Kiln 2					
NOx	137		19	19	0
SO2	9		5	5	0
PM10	1		1	1	0
Kiln 3					
NOx	274		154	124	30
SO2	16		18	18	0
PM10	4		16	16	0
Kiln 4					
NOx	647		687	309	378
SO2	18		8	8	0
PM10	1		23	23	0
Total NOx	1,352		1,164	671	493
Total SO2	150		138	138	0
Total PM10	8		59	59	0

5.8 PILOT PEAK PLANT REASONABLE PROGRESS OVERVIEW

For the purpose of determining whether controls at the Pilot Peak Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Pilot Peak Plant found in Appendix B.2.a. Pilot Peak's air quality operating permit is incorporated by reference into this SIP in Appendix A.2. Table 5-25 outlines the files referenced in making reasonable progress determinations for the Pilot Peak Plant, and where they can be found in Appendix B.

TABLE 5-25

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR PILOT PEAK

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Pilot Peak Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Determination*	May 2022	B.2.a
Reasonable Progress Four-Factor Analysis	*GW Analysis*	October 2020	B.2.b
RE: Graymont Pilot Peak Response to Federal Land Managers Comments on Four-Factor Analysis for Regional Haze	*Response Letter 1*	November 13, 2020	B.2.c
RE: Pilot Peak Response to NDEP Request for Additional Information Graymont Western US, Inc.	*Response Letter 2*	April 16, 2021	B.2.d
RE: Graymont Pilot Peak Response to the Initial Control Determination Letter	*Response Letter 3*	October 15, 2021	B.2.e
Class I Air Quality Operating Permit	Permit		A.2

5.8.1 Removing the Pilot Peak Plant from Consideration of Potential New Control Measures

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_X, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the Pilot Peak Plant is Jarbidge Wilderness Area at 131 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 5-26, using 2014 NEIv2 emissions, the Pilot Peak Plant yielded a Q/d value of 5.15, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

TABLE 5-26

ORIGINAL Q/D DERIVATION FOR PILOT PEAK

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2 +PM_{10}) [tpy]	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
523	23	127	673	131	**5.15**

These emissions were pulled from the 2014 NEIv2, based on NO_X emission rates presented in Table 5-27, however, in *Response Letter 2*, Graymont indicated that the emissions reported in the 2014 NEIv2, particularly the NO_X emissions, did not agree with what was submitted by Graymont for Pilot Peak's 2014 Annual Emission Inventory (AEI). Graymont's AEI for Pilot Peak in 2014 resulted in a Total Q of 604 tons per year (tpy), rather than 673, resulting in a Q/d of 4.61 (see Table 5-28). The change in resulting Total Q is primarily due to different NO_X emission rates used to calculate total NO_X emissions. Table 5-29 shows Graymont's calculated NO_X emissions for 2014 to be compared to Table 5-27 that outlines NO_X emissions reported into the 2014 NEIv2.

As seen in Table 5-27, the 2014 NEIv2 emissions calculated NO_X emissions for the Pilot Peak Plant kilns in 2014 using a NO_X emission rate in pound per hour, multiplied by the annual hours of operation for each kiln. This produced facility-wide NO_X emissions at 523 tons per year, resulting in a Q/d of 5.15. Alternatively, as seen in Table 5-29, Graymont calculated NO_X emissions for the Pilot Peak kilns in 2014 using a NO_X emission rate in pounds of NO_X per ton of lime produced, multiplied by the annual lime production rate for each kiln in tons per year. This produced facility-wide NO_X emissions at 459 tons per year, resulting in a Q/d of 4.61.

TABLE 5-27

NDEP-CALCULATED NO_X EMISSIONS FOR PILOT PEAK IN 2014

Unit	NO_x Emission Rate (lb/hr)	Hours of Operation (hr/yr)	NO_x Emissions (tpy)
Kiln 1	47.5	7033	167
Kiln 2	40.1	7033	141
Kiln 3	60.2	7153	215
		Total NO_x Emissions	**523**

TABLE 5-28

UPDATED Q/D DERIVATION FOR PILOT PEAK

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2 +PM_{10}) [tpy]	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
459	23	122	604	131	**4.61**

TABLE 5-29

GRAYMONT-CALCULATED 2014 NO_X EMISSIONS FOR UPDATED Q/D

Unit	NO_x Emission Rate (lb NO_x/ton lime)	Lime Production Rate (tons/yr)	NO_x Emissions (tpy)
Kiln 1	2.102	125,313	131.69
Kiln 2	1.302	199,362	129.78
Kiln 3	1.374	287,132	197.32
		Total NO_x Emissions	**459**

NDEP has reviewed the reporting requirements for NO_X emissions in the Pilot Peak Plant's air quality operating permit and confirms that the permitted procedure is to calculate NO_X emissions for each kiln using NO_X emission rates in pounds of NO_X per ton of lime produced, and annual lime production rates in tons per year. Because of this, Graymont no longer places above the set Q/d threshold of 5 and, therefore, is formally screened out of a four-factor analysis requirement and is not considered further for potential new control measures.

A comparison to other reporting years, and their resulting Q/d values, were conducted for years 2015 through 2020. As shown in Table 5-30, the following four operating years (2015-2018) also yield Q/d values below 5, while 2019 and 2020 yield a Q/d value above 5.

TABLE 5-30

Q/D COMPARISON AMONG OPERATING YEARS AT PILOT PEAK

	Facility Emissions (tpy)						
Pollutant	**2014***	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NO_X	459	406	451	395	418	562	700
SO_2	23	25	15	15	18	19	18
PM_{10}	122	66	75	70	68	77	80
Total	**604**	**497**	**541**	**480**	**504**	**658**	**798**
Q/d	**4.61**	**3.79**	**4.13**	**3.66**	**3.85**	**5.02**	**6.09**

*Updated 2014 emissions submitted in Graymont's AEI

Although emissions reported in 2019 and 2020 yield Q/d values above 5, NDEP does not find that it is reasonable to screen the source back into a four-factor analysis requirement for consideration of potential new measures for the following reasons:

1. Arbitrary Action – NDEP is reluctant to hold the Pilot Peak Plant to a different reporting year than other sources for source selection, as this can be seen as an arbitrary action. All other sources in the state of Nevada were considered for source selection using 2014 emissions, Pilot Peak would be the sole facility that was held to a different reporting year.
2. Emission Inventories – the WRAP states uniformly agreed to conduct source selection through the Q/d analysis using emissions from the NEI so emissions for all Western States could be easily accessed and reviewed by the Western Regional Air Partnership (WRAP) States and members. WRAP agreed to rely on the 2014 NEIv2 for source selection. This was done so that the Representative Baseline emission inventory (based on years 2014-2018) used in the SIP would agree with emissions used for source selection. At the time source selection was conducted, in August of 2019, 2017 and 2020 NEI were not yet available. Even if NDEP elected to rely on 2017 NEI emissions for source selection when it was released, Graymont would have had a Q/d of 3.66. The 2020 NEI is still not yet available.
3. Overall Q/d - considering Q/d values for 2014 through 2020, five of the seven years, or clear majority, show a Q/d value below NDEP's set threshold. The average Q/d across all seven years is 4.45, also falling below the threshold of 5.

Graymont did not provide updated 2014 emissions, subsequently screening them out of the four-factor requirement, until after they had already provided source information for a four-factor analysis (*GW Analysis*). Graymont has volunteered to include all information submitted for a four-factor analysis to demonstrate their efforts in remaining compliant with the requirements of the Regional Haze Rule, but do not intend for the submitted information to be used to consider new potential control measures for the second implementation period of the Regional Haze Rule in Nevada.

Although no new measures were formally considered to achieve reasonable progress at the Pilot Peak kilns, NDEP still evaluated whether any existing measures at the facility were necessary to achieve reasonable progress, outlined in the following sections.

5.8.2 Decisions on What Control Measures are Necessary to Make Reasonable Progress

NDEP evaluated whether existing SO_2, PM_{10}, and NO_x control measures at the Pilot Peak are necessary to make reasonable progress in NDEP's "Reasonable Progress Control Determination" for the Pilot Peak Plant found in Appendix B.2.a.

In this document, a robust weight-of-evidence demonstration is provided for existing SO_2 and PM_{10} control measures at the Pilot Peak Plant to determine that these controls are not necessary to make reasonable progress. Historical and projected emission rates for PM_{10} and SO_2 remain low and consistent, making it reasonable to assume that the source will continue to implement its existing measures and will not increase its emission rate.

For the control of NO_x emissions, Graymont Western has implemented LNBs at all three of the Pilot Peak kilns in recent years. NDEP identifies the continued use of existing LNBs at all three kilns as necessary to make reasonable progress. The determination of the new NOx limits, and other associated requirements, that reflect the use of Low-NO_x Burners at all Pilot Peak kilns is provided in NDEP's "Reasonable Progress Control Determination" for Pilot Peak.

The following requirements are established in the Pilot Peak Plant's air quality operating permit (Permit No. AP3274-1329.03) as enforceable permit conditions (Table 5-31). The referenced permit conditions below are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Pilot Peak Plant's current air quality permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.2.

TABLE 5-31

PILOT PEAK PLANT PERMIT CONDITIONS INCORPORATED BY REFERENCE

Pilot Peak Plant, Permit No. AP3274-1329.03		
	Citation	Permit Condition
Kiln 1 (System 10 – Kiln #1 Circuit)		
NO_x	IV.I.1.a	Emissions from **S2.031 through S2.033** shall be controlled by a baghouse (D-85) and **Low-NOx Burners.**
	IV.I.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-85)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere shall not exceed 101.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.I.4.q IV.I.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 2 (System 13 – Kiln #2 Circuit)		
NO_x	IV.L.1.a	Emissions from **S2.036 through S2.038** shall be controlled by a baghouse (D-285) and **Low-NOx Burners.**
	IV.L.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-285)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere shall not exceed 107.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.L.4.q IV.L.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 3 (System 17 – Kiln #3 Circuit)		
NO_x	IV.Q.1.a	Emissions from **S2.042 through S2.044** shall be controlled by a baghouse (D-385) and **Low-NOx Burners.**
	IV.Q.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from **the exhaust stack of baghouse (D-385)** the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of **NOx** to the atmosphere

		shall not exceed 143.7 pounds per hour, based on a 30-day rolling average period.
	V.B-C	**NOx (CEMS) Requirements for System 10** (S2.031, S2.032, and S2.033), **System 13** (S2.036, S2.037, S2.038), and **System 17** (S2.042, S2.043, S2.044)
	IV.Q.4.q IV.Q.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements

5.4.4 Discussion of Pilot Peak Plant Four-Factor Outcome

Although NO_X emission limits will be reduced within the source's air quality operating permit, these levels have already been achieved in practice over the past several years, and beyond the scope of the second implementation period of the Regional Haze Rule for Nevada. Because of this, there are no expected emission reductions within the WRAP emission inventories, or as a result of the final four-factor analysis. An emissions summary is provided in Table 5-32.

Although there is a slight difference in emissions between 2028OTBa2 and the Emissions After Controls inventories, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at the Pilot Peak Plant.

TABLE 5-32

PILOT PEAK MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Kiln 1					
NOx	167		135	135	0
SO2	3		1	1	0
PM10	18		17	17	0
Kiln 2					
NOx	141		173	173	0
SO2	6		1	1	0
PM10	31		25	25	0
Kiln 3					
NOx	215		207	207	0
SO2	14		4	4	0
PM10	5		51	51	0
Total NOx	523		515	515	0
Total SO2	23		6	6	0
Total PM10	54		93	93	0

5.9 FERNLEY PLANT FOUR FACTOR ANALYSIS

For the purpose of determining whether controls at the Fernley Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the Fernley Plant found in Appendix B.4.a. Table 5-33 outlines the files referenced in making reasonable progress determinations for the Pilot Peak Plant, and where they can be found in Appendix B.

TABLE 5-33

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR FERNLEY

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Fernley Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Control Determination*	March 2022	B.4.a
Regional Haze – Four Factor Analysis	*NCC Analysis*	October 2020	B.4.b
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 1*	November 3, 2020	B.4.c
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 2*	January 7, 2021	B.4.d
Regional Haze Email	*NCC Email*	September 20, 2019	B.4.e

Nevada Cement Company's (NCC) Fernley Plant is a Portland cement manufacturing plant located in Fernley, Nevada, consisting of two coal-fired and/or natural gas-fired long-dry process kilns. Portland cement produced by NCC is a cementitious, crystalline compound composed primarily of calcium, aluminum, and iron silicates. Both kilns are rated at 30.55 tons per hour of clinker, translating to about 267,500 tons per year clinker for each kiln, or 535,000 tons per year plantwide.

Both kilns at the Fernley Plant currently operate baghouses for the control of particulate matter. NDEP considers the existing baghouses for both kilns as existing effective controls, therefore, additional PM_{10} control measures were not considered for the Fernley Plant kilns. However, NDEP considers the continued use of the existing baghouses at both kilns as necessary to achieve reasonable progress.

When considering existing and potential new SO_2 and NO_X control measures, it is important to note that the Fernley Plant is currently bound to the requirements of a USEPA Consent Decree to control NO_X and SO_2 emissions, which can be found via the following links:

United States of America v. Nevada Cement Company, Civil Action No. 3:17-cv-00302-MMD-WGC

https://www.justice.gov/enrd/consent-decree/file/1089586/download

https://www.justice.gov/enrd/consent-decree/file/1089596/download

To control SO_2 emissions, the Consent Decree requires that both kilns at the Fernley Plant emit no more than 1.1 pound of SO_2 per ton of clinker. The facility relies on inherent scrubbing of SO_2 emissions within the cement kilns and has since installed a Dry Sorbent Injection system to assist in achieving the relevant emission limits for both kilns. The Consent Decree ultimately requires that the 1.1 pound of SO_2 per ton of clinker emission rate be incorporated into the facility's Title V operating permit.

To control NO_X emissions, the facility is required to install Selective Non-Catalytic Reduction (SNCR), followed by Low-NO_X Burners. Currently, the facility has installed SNCR on both kilns and is in the demonstration period. As stated in Appendix A of the Consent Decree, after the demonstration period, the source is to submit a demonstration report for each kiln's SNCR performance. A final 30-day rolling average emission limit for NO_X for both kilns is then derived from the findings of the demonstration report. Once approved by EPA, or an alternative 30-day rolling average emission limit is provided by EPA, the new NO_X limit associated with the SNCR systems for both kilns is permanently incorporated into the Fernley Plant's NDEP air quality operating permit. The same procedure is required for the implementation of Low-NO_X Burners for each kiln.

NDEP does not consider the installation and continued use of SNCR and Low-NO_X Burners at both Fernley Plant kilns as necessary to achieve reasonable progress, as NDEP is incapable of determining emissions limits, associated requirements, and compliance schedules for the NO_X controls in a manner that would satisfy the applicable SIP requirements.

The Consent Decree also required the installation and continued use of Continuous Emission Monitoring Systems (CEMS) for both kilns to measure and monitor SO_2 and NO_X emissions. The facility has since implemented CEMS for both kilns successfully and relies on CEMS for SO_2 and NO_X emissions reporting.

NDEP is relying on the referenced Consent Decree to screen the facility out of further consideration of potential new control measures, as the outcome of the Consent Decree will inherently make both kilns BACT for NO_X, SO_2, and PM_{10} emissions. Once NCC has developed and finalized all associated limits to the consent decree controls, it is required that these new limits be incorporated into the facility's Title V permit, making the controls federally enforceable and permanent.

NDEP concludes that the consent decree controls for NO_X and SO_2 are not necessary to achieve reasonable progress as these new consent decree controls, and associated limits, will become federally enforceable and permanent through the source's Title V operating permit, as required by the USEPA Consent Decree, regardless of whether they are included in Nevada's Long-Term Strategy for the second implementation period of Regional Haze as necessary to achieve reasonable progress. Furthermore, anticipated reductions from the implementation of NO_X controls and achievement of new SO_2 limits required by the consent decree were not included in the 2028 RPGs developed in Chapter 6 for Jarbidge WA.

Although the Fernley Plant was not required to conduct a four-factor analysis for potential new control measures, the facility was asked to evaluate the continuous use of the facility's existing DSI system, as opposed to occasional use, considering the four statutory factors to achieve additional SO_2 emission reductions.

5.9.1 Baseline Emissions

The SO_2 emissions baseline used in the considering continuous operation of the existing DSI system is summarized in Table 5-34. These baseline emissions represent available SO_2 emissions that could be reduced after DSI has already been used to meet the SO_2 emission limit requirements listed in the consent decree.

TABLE 5-34

FERNLEY FOUR-FACTOR ANALYSIS BASELINE SO_2 EMISSIONS

Kiln	Baseline SO_2 Emissions (tpy)
1	114.6
2	106.8

5.9.2 Characterization of Cost of Compliance

Cost-effectiveness values for operating the existing DSI system at full capacity, provided in Table 5-35, are focused on achievable SO_2 reductions based on the baseline SO_2 emissions and assumed control efficiency of the control. A 30% SO_2 reduction is assumed, resulting in a cost-effectiveness value of $30,066 per ton of SO_2 reduced for Kiln 1 and $30,140 per ton of SO_2 reduced for Kiln 2.

TABLE 5-35

FERNLEY FOUR-FACTOR ANALYSIS COST-EFFECTIVENESS SUMMARY

Control	Kiln	Baseline SO_2 Emissions (tpy)	Assumed Control Efficiency	Tons SO_2 Reduced (tpy)	Total Annualized Cost	Cost-Effectiveness
Continuous use of DSI	1	114.6	30%	34.4	$1,034,274	$30,066 /ton
	2	106.8	30%	32.0	$964,491	$30,140 /ton

5.9.3 Characterization of Time Necessary for Compliance

Approximately 4 months is required to procure, build, install, and shakedown the new equipment for proper engineering.

5.9.4 Characterization of Energy and Non-Air Quality Environmental Impacts
In determining energy and non-air quality environmental impacts, NDEP is relying on NCC's statement provided in Section 5.6 of the NCC Analysis that states:

"The use of DSI full time (8,760 hr/yr) will have an energy penalty in terms of electricity needed to operate the larger blower (50 hp). The electricity requirement for the DSI system is approximately 39kW per hour (343,889 kW/yr) which equates to $19,051 per year... Kiln 1 and Kiln 2 are currently equipped with an as needed DSI system for SO_2 control. The lime reagent used in a DSI system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing fabric filter particulate control systems and either returned to the systems for reuse or removed from the systems as nonhazardous solid waste. Collateral environmental impacts associated with the DSI system include increased solid waste generation. Additionally, the operation of the DSI storage vessel's baghouse will emit an additional 0.2 tpy of PM (lime emissions)."

The additional electricity cost outlined above is included in the source's analysis for the cost of compliance. Although the control would require additional electricity to operate at full capacity, NDEP does not find this to be sufficient to warrant a no control determination. The calcium sulfate and calcium sulfite solids are either recycled back into the system or properly disposed of. This does not pose a threat to the surrounding non-air environment. Although there is a 0.2 tpy increase in PM emissions as a result of this control, adding this increase to the total reductions achieved by the control would not be impactful in the analysis.

5.9.5 Characterization of Remaining Useful Life of the Source
The cost analysis assumes a 20-year life for the DSI system on both kilns when calculating the annualized capital costs of the upgraded DSI system.

5.9.6 Decisions on what Control Measures are Necessary to Make Reasonable Progress
Considering the four statutory factors outlined above, NDEP does not consider the upgrade of the existing DSI system to operate at full capacity for both kilns as necessary to achieve reasonable progress. No other potential new control measures are considered for the Fernley Plant.

As stated above, NDEP does not consider the anticipated NO_X and SO_2 emission reductions resulting from the ongoing USEPA consent decree as necessary to achieve reasonable progress during the second implementation period.

NDEP also does not consider the existing baghouses used to achieve current PM_{10} emission limits listed in the facility's air quality operating permit as necessary to achieve reasonable progress. NDEP is relying on consistent historical emissions and referencing PM_{10} emissions limits (Table 5-36) listed in the Fernley Plant's permit, Permit No. AP3241-0387.02. A robust demonstration with supporting documentation is included in the source's Control Determination in Appendix B.

TABLE 5-36

FERNLEY PLANT PERMIT LIMITS FOR PM_{10}

Kiln	Pollutant	Limit (lb/hr)	Limit (tpy)
1	PM_{10}	14.83	64.96
2	PM_{10}	14.83	64.96

5.9.7 Discussion of Fernley Plant Four-Factor Outcome

Although there is a slight difference in emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 5-37, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Both 2028OTBa2 and the Emissions After Controls inventories use the same emission factors, however, 2028OTBa2 assumed actual operating hours reported in 2014 and Emissions After Controls assumed 8760 operating hours. Because of this, there will be no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at the Fernley Plant.

TABLE 5-37

FERNLEY MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Kiln 1					
NOx	544		1307	1307	0
SO2	62		167	167	0
PM10	58		125	125	0
Kiln 2					
NOx	554		1261	1261	0
SO2	64		167	167	0
PM10	57		125	125	0
Total NOx	1,098		2568	2568	0
Total SO2	126		334	334	0
Total PM10	115		250	250	0

5.10 TS POWER PLANT REASONABLE PROGRESS ANALYSIS

For the purpose of determining whether controls at the TS Power Plant are necessary to make reasonable progress during the second implementation period, NDEP is relying on NDEP's "Reasonable Progress Control Determination" for the TS Power Plant found in Appendix B.3.a. Table 5-38 outlines the files referenced in making reasonable progress determinations for the TS Power Plant, and where they can be found in Appendix B.

TABLE 5-38

LOCATION OF FOUR-FACTOR ANALYSIS DOCUMENTS FOR TS POWER

Full Document Title	**Shortened Document Title (used in this document)**	**Date**	**Appendix Location**
TS Power Plant Reasonable Progress Control Determination (NDEP)	*NDEP Reasonable Progress Control Determination*	March 2022	B.3.a
Reasonable Progress Analysis	*NNEI Analysis*	December 10, 2019	B.3.b

TS Power, built in 2008, was also removed from the four-factor requirement as the facility has state of the art Best Available Control Technology (BACT) that was included in the original design. It was confirmed that a four-factor analysis would not result in any cost-effective additional controls in the facility's Reasonable Progress Report submitted to NDEP (located in Appendix B.3.b) during the second implementation of the Regional Haze Rule. The TS Power Plant has one pulverized coal, dry bottom boiler with a gross capacity of 220 MW. Table 5-39 lists the existing controls that reduce visibility impairing pollutants at the facility, along with the corresponding BACT emission limits that can be found in the facility's air quality operating permit (Permit No. AP4911-2502).

Note that there are two BACT emission limits for SO_2, depending on the sulfur content of the coal burned. As seen in the below table, an SO_2 emission limit of 0.065 pounds per million british thermal units and minimum SO_2 control efficiency of 91% is enforced when the unit burns coal with a sulfur content less than 0.45%. When the unit is combusting coal with a sulfur content equal to or greater than 0.45%, the emission limit is raised to 0.09 pounds per million british thermal units, however, the increase in emissions is offset by an increased minimum SO_2 control efficiency of 95%.

TABLE 5-39

TS POWER PLANT BACT CONTROLS AND EMISSION LIMITS

Pollutant	Control	BACT Emission Limit (lb/MMBtu)
NO_x	Low-NO_x Burners Over Fired Air Selective Catalytic Reduction	0.067
SO_2	Lime Spray Dryer While combusting coal with a sulfur content equal to or greater than 0.45%	0.09 (95% minimum SO_2 removal efficiency required)
	Lime Spray Dryer While combusting coal with a sulfur content less than 0.45%	0.065 (91% minimum SO_2 removal efficiency required)
PM_{10}	Pulse Jet Fabric Filter Dust Collector	0.176

As stated above, the TS Power Plant has been determined as already operating BACT (best available control technology) controls for NO_x, SO_2, and PM_{10} emissions. In NDEP's "Reasonable Progress Control Determination" for TS Power, a robust weight-of-evidence demonstration is provided for existing NO_x, SO_2, and PM_{10} control measures at the TS Power Plant to determine that these controls are not necessary to make reasonable progress. Historical and projected emission rates for NO_x, SO_2, and PM_{10} remain low and consistent, making it reasonable to assume that the source will continue to implement its existing measures and will not increase its emission rates.

5.4.7 Cumulative Emissions Reductions

Significant emission reductions are expected to achieve reasonable progress for the second implementation period of Nevada's Regional Haze SIP. Emission reductions for all facilities conducting a four-factor analysis were estimated by both WRAP and NDEP. WRAP estimates were developed for modeling inventories, with 2028OTBa2 data using updated 2014 emissions. In NDEP's four-factor analyses calculations, baseline emissions were typically derived from more recent reporting years (e.g. average annual emissions from 2016 to 2018) and controlled emissions derived from the assumed control efficiency of any control that is cost-effective and necessary to achieve reasonable progress.

Emission reductions calculated from NDEP's four-factor analyses are more accurate than what was estimated for WRAP modeling, and provide a better image of achieved emission reductions as a result of Nevada's efforts during the second implementation period. WRAP modeling inventories used less recent emissions data for the baseline and only estimates of controlled emissions. Table 5-40 compares the total emission reductions between baseline and controlled emissions for WRAP modeling and NDEP's four-factor analyses. Total emissions across the four-factor sources were estimated at 7,964 tpy in WRAP 2028OTBa2 modeling, while NDEP's four-factor data indicates total emissions across four-factor sources at 5,139 tpy. This translates to a difference of nearly 3,000 tpy.

Figure 5-1 compares NDEP's calculation of baseline and controlled emissions among the sources in Nevada considered for reasonable progress controls. SO_2 emissions show a total reduction of 2,313 tons per year, NO_X emissions show a total reduction of 2,239 tons per year, and PM_{10} emissions show a total reduction of 60 tons per year. Referring to more current and accurate baseline emissions used in the four-factor analyses, Nevada expects a total reduction in primary visibility impairing pollutants (SO_2, NO_X, and PM_{10}) of 4,612 tons per year as a result of the four-factor analyses conducted to achieve reasonable progress for the second round.

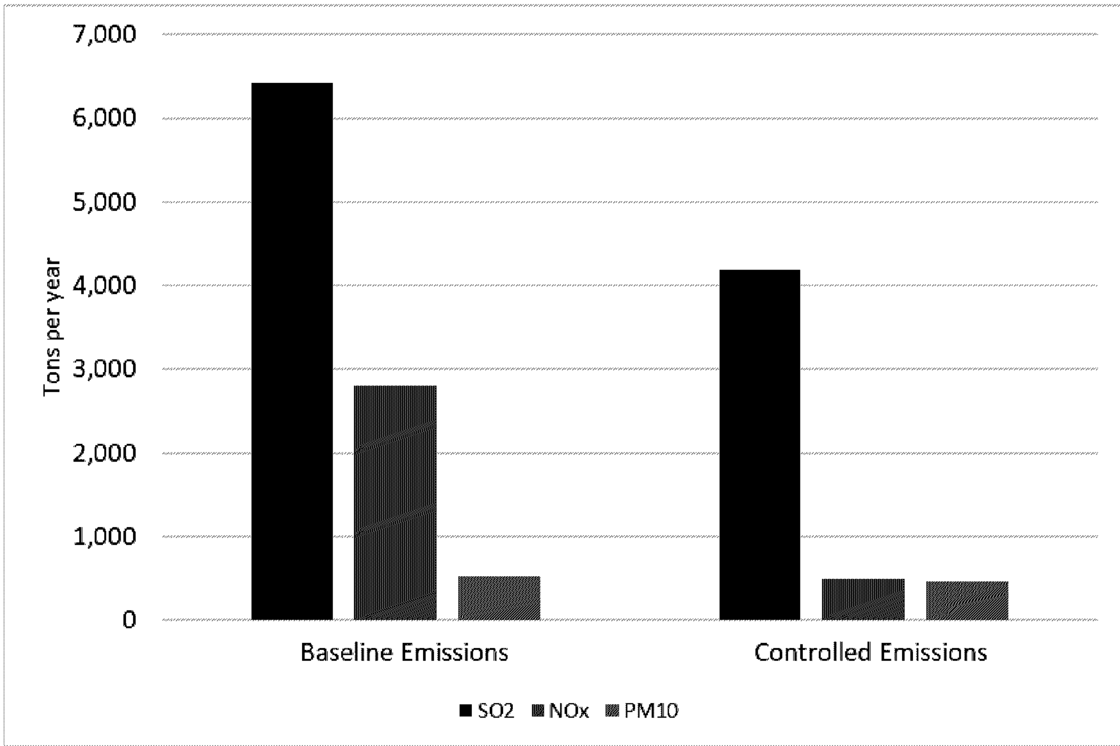
TABLE 5-40

TOTAL MODELING VS. FINAL EMISSIONS REDUCTIONS
DURING SECOND ROUND IN TONS PER YEAR

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Valmy					
NOx	1583		1746	0	1746
SO2	2,281		2,313	0	2313
PM10	77		60	0	60
Tracy					
NOx	503		434	434	0
SO2	11.5		12	12	0
PM10	59		59	59	0
Apex					
NOx	1,352		1164	671	493
SO2	150		138	138	0
PM10	8		59	59	0
Pilot Peak					
NOx	523		515	515	0
SO2	23		6	6	0
PM10	54		93	93	0
Fernley					
NOx	1,098		2568	2568	0
SO2	126		334	334	0
PM10	115		250	250	0
Total					
NOx	5,059		6427	4188	2239
SO2	2,592		2803	490	2313
PM10	313		521	461	60
Grand Total	7,964		9,751	5,139	**4,612**

FIGURE 5-1

BASELINE AND CONTROLLED EMISSIONS COMPARISON FOR REASONABLE PROGRESS DURING THE SECOND IMPLEMENTATION PERIOD



5.11 ENVIRONMENTAL JUSTICE IMPACT ANALYSIS OF FOUR-FACTOR SOURCES

The Regional Haze Rule requires that states consider non-air quality environmental impacts as one of the four statutory factors when evaluating potential additional controls. Consideration of Environmental Justice (EJ) and the impact control decisions may have on potentially vulnerable communities falls within this category. NDEP has modeled its EJ analysis after the EJ analysis found in Oregon's Regional Haze Plan Support Document[1]. In NDEP's Regional Haze EJ analysis, communities within a 3-mile and 10-mile radius of each source identified by NDEP's Q/d source screening method were examined for any patterns of disproportionate burden of environmental pollution on vulnerable communities using the 2020 version of EPA's EJSCREEN tool.

This version of EJSCREEN uses the 2014-2018 five-year American Community Survey data for demographic indicators:

- People of Color Population (%)
- Low Income Population (%)
- Linguistically Isolated Population (%)
- Population With Less Than High School Education (%)
- Population Under 5 Years of Age (%)
- Population Over 64 Years of Age (%)

These indicators are standard demographic indicators commonly used by EPA and other state agencies when considering Environmental Justice impacts. Each indicator is represented in percentage of the total recorded population within the designated radius around each facility.

For each facility, NDEP tallied a “1” if the value of that indicator was above the statewide average, or a “0” if the value was below the statewide average. Figures 5-2 and 5-3 below show the number of indicators for which the community within a facility was above the statewide average, achieving a maximum of 6 and minimum of 0. If a census block was only partially contained within the radius of the facility, then the value for that census block group was scaled to the proportion of the block group within the circle. An outline of the demographic indicator values recorded within the radius of each facility is included in the Tables 5-41 and 5-42 below and compared to the statewide average. Indicators that are above the statewide average are highlighted and represent a tally of “1.” An “N/A” value indicates a census population of 0 in that facility’s radius. A facility with a vulnerability score of 4 or more would indicate a significant impact on vulnerable communities and would require further consideration in deciding what controls at the facility may be necessary for reasonable progress in Nevada’s second implementation period of the Regional Haze Rule.

FIGURE 5-2

NUMBER OF SOCIOECONOMIC INDICATORS FOR COMMUNITIES
WITHIN 3 MILES OF A FOUR-FACTOR FACILITY

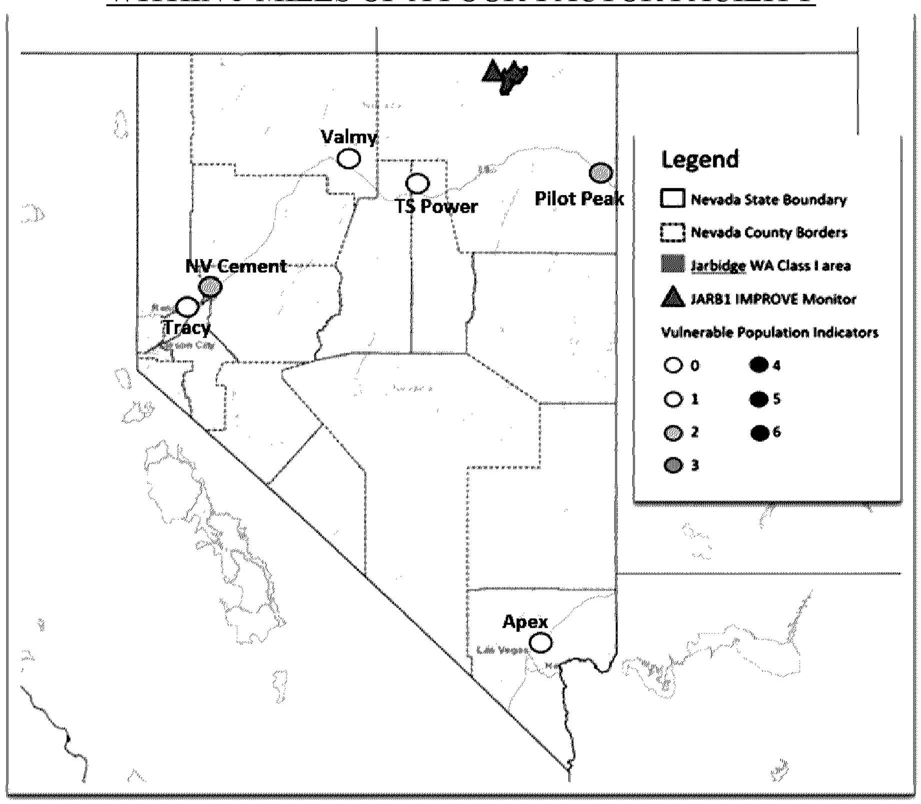


TABLE 5-41

DEMOGRAPHIC INDICATORS FOR EACH FACILITY
COMPARED TO STATEWIDE AVERAGES USING A 3-MILE RADIUS

Demographic Indicator	North Valmy GS	Tracy GS	TS Power Plant	Statewide Ave.
Population Count	0	16	2	3,100,00
People of Color	N/A	14%	20%	50%
Low Income	N/A	16%	7%	34%
Linguistically Isolated	N/A	0%	0%	6%
< High School Education	N/A	4%	8%	14%
< 5 Years of Age	N/A	2%	5%	6%
> 64 Years of Age	N/A	39%	12%	15%
Demographic Indicator	Fernley Plant	Apex Plant	Pilot Peak Plant	Statewide Ave.
Population Count	12,316	0	2	3,100,00
People of Color	32%	N/A	44%	50%
Low Income	33%	N/A	51%	34%
Linguistically Isolated	0%	N/A	0%	6%
< High School Education	13%	N/A	25%	14%
< 5 Years of Age	7%	N/A	4%	6%
> 64 Years of Age	17%	N/A	11%	15%

FIGURE 5-3

NUMBER OF SOCIOECONOMIC INDICATORS FOR COMMUNITIES
WITHIN 10 MILES OF A FOUR-FACTOR FACILITY

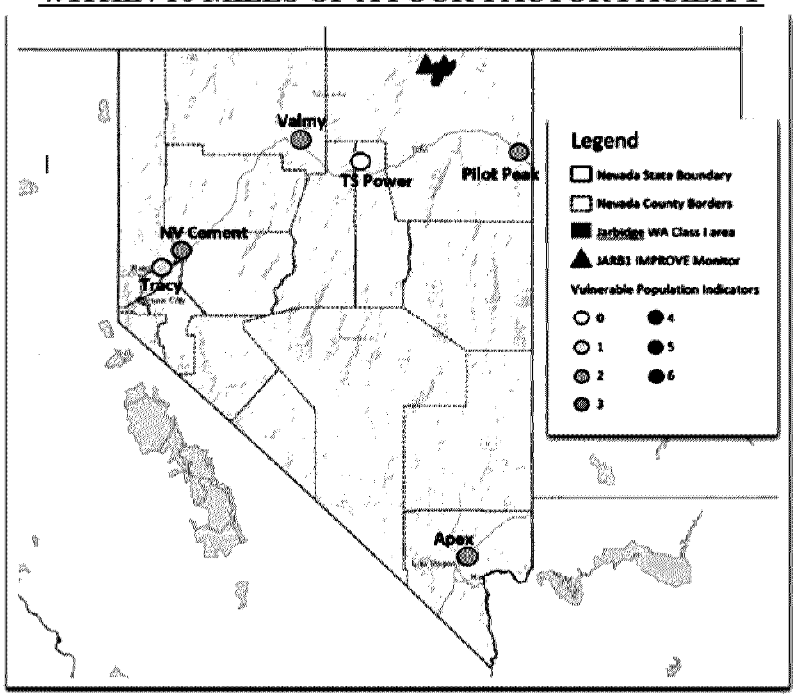


TABLE 5-42

DEMOGRAPHIC INDICATORS FOR EACH FACILITY
COMPARED TO STATEWIDE AVERAGES USING A 10-MILE RADIUS

Demographic Indicator	North Valmy GS	Tracy GS	TS Power Plant	Statewide Ave.
Population Count	83	30,047	21	3,100,00
People of Color	35%	26%	20%	50%
Low Income	44%	13%	7%	34%
Linguistically Isolated	4%	2%	0%	6%
< High School Education	27%	5%	8%	14%
< 5 Years of Age	4%	5%	5%	6%
> 64 Years of Age	12%	20%	12%	15%
Demographic Indicator	Fernley Plant	Apex Plant	Pilot Peak Plant	Statewide Ave.
Population Count	20,956	78	11	3,100,00
People of Color	28%	57%	44%	50%
Low Income	29%	35%	51%	34%
Linguistically Isolated	1%	5%	0%	6%
< High School Education	11%	3%	25%	14%
< 5 Years of Age	7%	0%	4%	6%
> 64 Years of Age	17%	0%	11%	15%

The six facilities that underwent the four-factor review are generally located in sparsely populated rural areas. Among the six sources, only the Nevada Cement Fernley Plant has a significantly large population within a 3-mile radius. Two sources, North Valmy and TS Power, have no population. The Lhoist Apex facility located just outside the Las Vegas metropolitan area, has very few residents living nearby. Similarly, the Tracy plant near the Reno/Sparks area is situated where there are few residents. Of the four sources that have a reported population, a maximum of two indicators were recorded above the statewide average.

When evaluating the same facilities at a 10-mile radius, the conclusion remains relatively the same, with a few changes. North Valmy Generating Station and the Apex Plant now have a population value with corresponding EJSCREEN Tool data. With this, both North Valmy and Apex Plant show two indicators that are above the statewide average. Fernley Plant's population nearly doubles with the larger radius; however, the two indicators of concern remain the same. Tracy Generating Station's population increased by nearly 30,000 people and demonstrates the benefit of evaluating larger distances around facilities, however, the sole indicator of concern remains the same. Of all six sources, it remains true that a maximum of two indicators were recorded above the statewide average for each source.

In considering the communities within a 3-mile and 10-mile radius of Nevada's Regional Haze sources, NDEP concludes that there is no significant impact on vulnerable communities that would further provide evidence that a control currently not being considered as "necessary for reasonable progress" should be installed.

5.12 REFERENCES

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

ATTACHMENT RA-4

North American Electric Reliability Corporation, PRC-010-1 – Undervoltage Load Shedding

A. Introduction

1. **Title: Undervoltage Load Shedding**

2. **Number: PRC-010-1**

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator

   4.1.2 Transmission Planner

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Background:**

PRC-010-1 – Undervoltage Load Shedding is a consolidation and revision of the following Reliability Standards:

- PRC-010-0 – Assessment of the Design and Effectiveness of UVLS Program
- PRC-020-1 – Under-Voltage Load Shedding Program Database
- PRC-021-1 – Under-Voltage Load Shedding Program Data
- PRC-022-1 – Under-Voltage Load Shedding Program Performance

The UVLS Standard Drafting Team (or drafting team) developed the revised PRC-010-1 to meet the following objectives:

- Address the FERC directive in Order No. 693, Paragraph 1509 to modify PRC-010-0 to require an integrated and coordinated approach to all protection systems.
- Replace the applicability to and involvement of the Regional Reliability Organization (RRO) in PRC-020-1 and PRC-021-1.
- Consolidate the UVLS-related standards into one comprehensive standard (similar to the construct of FERC-approved PRC-006-1– Automatic Underfrequency Load Shedding).
- Clearly identify and separate centrally controlled undervoltage-based load shedding due to the reliability requirements needed for this type of load shedding as compared to other UVLS systems.
- Create a single results-based standard that addresses current reliability issues associated with UVLS.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate whether its UVLS Program resolved the undervoltage issues associated with the event. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies in its UVLS Program during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Introduction

PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in its legacy standards, PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1. The standard also addresses a FERC directive from Order No. 693, Paragraph 1509. This paragraph directs NERC to develop a modification to PRC-010-0 that requires an integrated and coordinated approach to all protection systems, including generators and transmission lines, generators' low voltage ride-through capabilities, and underfrequency load shedding (UFLS) and UVLS programs.

Since FERC-approved PRC-006-1 – Automatic Underfrequency Load Shedding was developed under a similar construct of combining existing standards and addressing a FERC Order No. 693 directive, the drafting team looked to this standard as a guide. With the understanding that UVLS and UFLS systems have fundamental differences, the drafting team adopted PRC-006-1's industry-vetted reliability principles and language as applicable to UVLS Programs.

The drafting team's established purpose for PRC-010-1 is to clearly define the responsibilities of applicable entities to pursue an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS Programs. Since the need for and design of UVLS Programs is unique to each system preservation footprint, the intent of the standard is to provide a framework of reliability requirements for such programs to which each individual entity can apply its program's specific considerations and characteristics. The drafting team emphasizes that PRC-010-1 does not require a mandatory UVLS Program, nor does this standard address the need to have a UVLS Program. PRC-010-1 applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.

The drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

The design and characteristics of a centrally controlled undervoltage-based load shedding system are commensurate with a Special Protection System (SPS) or Remedial Action Scheme (RAS), therefore, the drafting team maintains that this type of load shedding should be covered by SPS-or-RAS-related Reliability Standards. Therefore, PRC-010-1 introduces a new Glossary of Terms Used in NERC Reliability Standards term, UVLS Program, to establish the applicability of PRC-010-1 to automatic load shedding programs consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Undervoltage-based load shedding that does not have such an impact as determined by the Planning Coordinator or Transmission Planner is not included. It is further noted that this term excludes centrally controlled undervoltage-based load shedding.

Subsequently, since the current Glossary of Terms Used in NERC Reliability Standards definition of Special Protection System excludes UVLS, concurrent Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) will adjust the definition to exclude only UVLS Programs as defined above and therefore include centrally controlled undervoltage-based load shedding. Of note, the drafting team for Project 2010-05.2 is proposing to change the term from Special Protection System to Remedial Action Scheme. Accordingly, PRC-010-1 uses the term Remedial Action Scheme instead of Special Protection System. In the current inventory of NERC Reliability Standards, there is one instance of the term undervoltage load shedding program, which is in NUC-001-2.1. Project 2012-13–Nuclear Plant Interface Coordination has adjusted the language of this reference in proposed NUC-001-3 to eliminate any potential confusion of a lowercase usage of a defined term. Likewise, future projects containing standards that feature variations of the term (e.g., undervoltage load shedding system) will also be advised to consider the newly defined term.

Requirements of the revised Reliability Standard PRC-010-1 meet the following objectives:

- Evaluate a UVLS Program's effectiveness prior to implementation, including the program's coordination with other protection systems and generator voltage ride-through capabilities.
- Adhere to UVLS Program specifications and implementation schedule.
- Perform periodic assessment and performance analysis of UVLS Programs and resolve identified deficiencies.
- Maintain and share UVLS Program data.

Also of note, Project 2009-03 – Emergency Operations is proposing EOP-011-1, which, as part of the overall revisions, retires specific requirements from EOP-003-2 – Load Shedding Plans to eliminate identified redundancy between PRC-010-1 and EOP-003-2. In addition, the UVLS drafting team's intention is for PRC-004 to address Misoperations of UVLS Programs that are intended to trip one or more BES Elements. A change to make these types of UVLS Programs explicitly applicable to PRC-004 will be addressed once PRC-004-3 – Protection System Misoperation Identification and Correction is completed under Project 2010-05.1 – Misoperations (Phase 1 of Protection Systems).

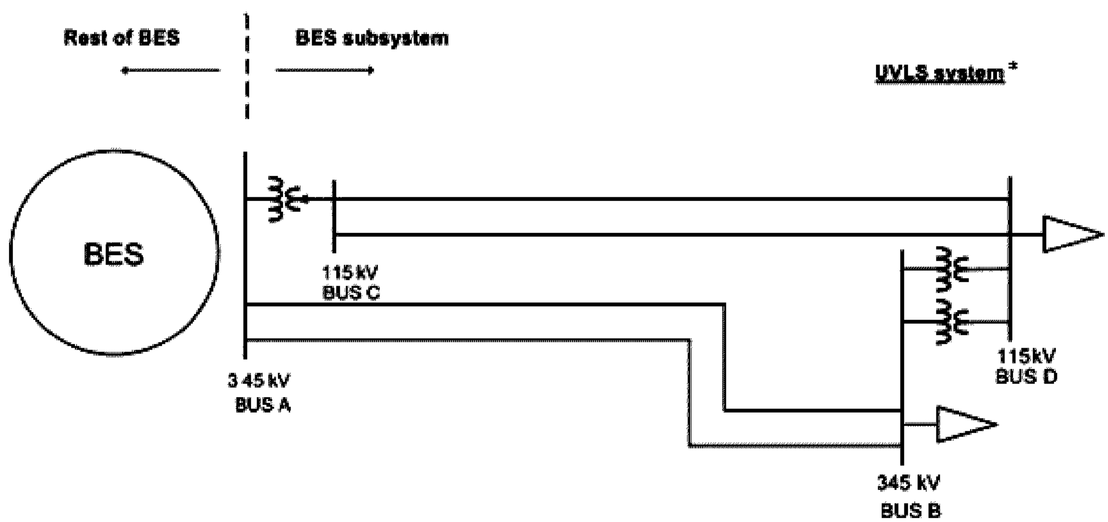
Guidelines for UVLS Program Definition

The definition for the term UVLS Program includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The definition for the term UVLS Program excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a RAS, wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard is to only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the BES. An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Below is an example of a BES subsystem for which UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between bus A and bus B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading involving the BES, UVLS system (installed at either, or both, bus B and D) used to mitigate this case would not fall under the definition of a UVLS Program. However, if this same UVLS system would be used to mitigate Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



*UVLS systems may be installed at either, or both, bus B and D

High Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1:

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static var systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

Examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2:

Once a Planning Coordinator or Transmission Planner has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, the location at which load needs to be shed, etc. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

> CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:
>
> PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks.

The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the misoperation of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3:

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment should be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment supplements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

With respect to situations in which a material change to system and topology or operating conditions would necessitate a comprehensive assessment of the UVLS Program, it is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4:

The goal of the assessment required in Requirement R4 is to evaluate whether the UVLS Program resolved the undervoltage issues for an event that occurred on the system. It is expected that the assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event shall be performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5.

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5:

Requirement R5 promotes the prudent correction of an identified problem during assessment evaluations of each UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate.
- At least once every 60 months. The default time frame of 60 months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated.

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, the drafting team believes that within three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop remedial action plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted

- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS, and RAS.

Additionally, the UVLS Program database should be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Completed revision, merged and updated PRC-010-0, PRC-020-1, PRC- 021-1, and PRC-022-1.
1	November 19, 2015	FERC approved PRC-010-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase “Planning Coordinator or Transmission Planner” provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate whether the UVLS Program resolved the undervoltage issues associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission

Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment of a UVLS Program performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

ATTACHMENT RA-5

Excerpt of Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 33,654, 33,654–36,666, 36,754–36,844 (June 5, 2023)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78, and 97

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

RIN 2060–AV51

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

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

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

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

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (312) 886–4746; email address: *selbst.elizabeth@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1 2016 Version 1 Emissions Modeling Platform
2016v2 2016 Version 2 Emissions Modeling Platform
4-Step Framework 4-Step Interstate Transport Framework
ABC Associated Builders and Contractors
ACS American Community Survey
ACT Alternative Control Techniques
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQS Air Quality System
BACT Best Available Control Technology
BART Best Available Retrofit Technology
BOF Basic Oxygen Furnace
BPT Benefit Per Ton
C1C2 Category 1 and Category 2
C3 Category 3
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCR Coal Combustion Residual
CDC Centers for Disease Control and Prevention
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CFB Circulating Fluidized Bed Units
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CRA Congressional Review Act
CSAPR Cross-State Air Pollution Rule
DAHS Data Acquisition and Handling System
DOE Department of Energy
EAF Electric Arc Furnace
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EIS Emissions Inventory System
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
ERT Electronic Reporting Tool
FERC Federal Energy Regulatory Commission
FFS Findings of Failure to Submit
FIP Federal Implementation Plan
GIS Geographic Information System
g/hp-hr grams per horsepower per hour
HDGHG Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD High Electricity Demand Days
ICI Industrial, Commercial, and Institutional
I/M Inspection and Maintenance
IPM Integrated Planning Model
IRA Inflation Reduction Act
LAER Lowest Achievable Emission Rate
LDC Local Distribution Company
LME Low Mass Emissions
LNB Low-NO_X Burners
MATS Mercury and Air Toxics Standards
MCM Menu of Control Measures
MDA8 Maximum Daily Average 8-Hour
MJO Multi-Jurisdictional Organization
MOU Memorandum of Understanding
MOVES Motor Vehicle Emissions Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NERC North American Electric Reliability Corporation
NESHAP National Emissions Standards for Hazardous Air Pollutants
NMB Normalized Mean Bias
NME Normalized Mean Error
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NODA Notice of Data Availability
NO_X Nitrogen Oxides
NREL National Renewable Energy Lab
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OFA Over-Fire Air
OMB United States Office of Management and Budget

OSAT/APCA Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis
OTC Ozone Transport Commission
OTR Ozone Transport Region
OTSA Oklahoma Tribal Statistical Area
PDF Portable Document Format
PEMS Predictive Emissions Monitoring Systems
$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmv parts per million by volume
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PTE Potential to Emit
RACT Reasonably Available Control Technology
RATA Relative Accuracy Test Audit
RCF Relative Contribution Factor
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
RTC Response to Comments
RTO Regional Transmission Organization
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCC Source Classification Code
SCR Selective Catalytic Reduction
SIL Significant Impact Level
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TAS Treatment as State
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VMT Vehicle Miles Traveled
VOCs Volatile Organic Compounds
WRAP Western Regional Air Partnership
WRF Weather Research and Forecasting

Table of Contents

I. Executive Summary

This final rule resolves the interstate transport obligations of 23 states under CAA section 110(a)(2)(D)(i)(I), referred to as the "good neighbor provision" or the "interstate transport provision" of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to submit to EPA ozone infrastructure State Implementation Plan (SIP) revisions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018. The EPA proposed the subject rule to address outstanding interstate ozone transport obligations for the 2015 ozone NAAQS in the **Federal Register** on April 6, 2022 (87 FR 20036).

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

The EPA is finalizing FIP requirements for 21 states for which the Agency has, in a separate action, disapproved (or partially disapproved) ozone transport SIP revisions that were submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Texas, Utah, West Virginia, and Wisconsin. *See* 88 FR 9336. In this final rule, the EPA is issuing FIPs for two states—Pennsylvania and Virginia—for which the EPA issued Findings of Failure to Submit for 2015 ozone NAAQS transport SIPs. *See* 84 FR 66612 (December 5, 2019). Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2]

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

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

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

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

This final rule implements the necessary emissions reductions as follows. Under the FIP requirements, EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) are required to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] In addition to reflecting emissions reductions based on the Agency's determination of the necessary control stringency in this rule, the revised trading program includes several enhancements to the program's design to better ensure achievement of the selected control stringency on all days of the ozone season and over time. For 12 states already required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) under the Revised CSAPR Update (with respect to the 2008 ozone NAAQS), the FIPs are amended by the revisions to the Group 3 trading program regulations. For seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. The EPA is issuing new FIPs for three states not currently covered by any CSAPR NO_X ozone season trading program: Minnesota, Nevada, and Utah.

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

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

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

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

The EPA is making a finding that NO_X emissions from certain non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NO_X emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA is establishing emissions limitations beginning in 2026 for non-EGU sources located within 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The final rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in

[3] As explained in section V.C.1 of this document, the EPA is making a finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

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

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in downwind states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section III of this document provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[5,6] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[7]

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[8] Within 3 years of the EPA promulgating a new or revised NAAQS, all states are required to provide SIP submittals, often referred to as "infrastructure SIPs," addressing certain requirements, including the good neighbor provision. *See* CAA section 110(a)(1) and (2). The EPA must either approve or disapprove such submittals or make a finding that a state has failed to submit a complete SIP revision. As with any other type of SIP under the Act, when the EPA disapproves an interstate transport SIP or finds that a state failed to submit an interstate transport SIP, the CAA requires the EPA to issue a FIP to directly implement the measures necessary to eliminate significant contribution under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this rule, the EPA is finalizing requirements to fully address good neighbor obligations for the covered states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c). By eliminating significant contribution from these upwind states, this rule will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country. At any time after the effective date of this rule, states may submit a Good Neighbor SIP to replace the FIP requirements contained in this rule, subject to EPA approval under CAA section 110(a).

The EPA conducted air quality modeling for the 2023 and 2026 analytic years to identify (1) the downwind areas identified as "receptors" (which are associated with monitoring sites) that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality problems. We use the term "downwind" to describe those states or areas where a receptor is located, and we use the term "upwind" to describe states whose emissions are linked to one or more receptors. States may be both downwind and upwind depending on the receptor or linkage in question. Section IV of this document provides a full description of the results of the EPA's updated air quality modeling and relevant analyses for the rulemaking, including a discussion of how updates to the modeling and air quality analysis following the proposed rule have resulted in some modest changes in the overall geography of the final rule. Based on the EPA's air quality analysis, the 23 upwind states covered in this action are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in downwind states. The EPA intends to expeditiously review the updated air quality modeling and related analyses to address potential good neighbor requirements of six additional states—Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming—in a subsequent action. The EPA had previously approved 2015 ozone transport SIPs submitted by Oregon and Delaware, but in the proposed FIP action the EPA found these states potentially to be linked in the modeling supporting our proposal. We proposed to issue an error correction for our prior approval of Delaware's 2015 ozone transport SIP; however, in this final rule, the EPA is withdrawing the proposed error correction and the proposed FIP for Delaware, because our updated modeling for this final rule confirms that Delaware is not linked above the 1 percent of NAAQS threshold (*see* section III.C.1 of this document for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

1. Emissions Limitations for EGUs Established by the Final Rule

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

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

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

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

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

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

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

Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs also require affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the "Group 2 trading program") under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.[9] Finally, the EPA is issuing new FIPs for EGUs within the borders of three states not currently covered by any existing CSAPR trading program for seasonal NO_X emissions: Minnesota, Nevada, and Utah. Sources in these states will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[10] Refer to section VI.B of this document for details on EGU regulatory requirements.

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

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

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

B. Summary of the Regulatory Framework of the Rule

The EPA is applying the 4-step interstate transport framework developed and used in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to define and implement good neighbor obligations for the 2015 ozone NAAQS. The four steps are as follows: (Step 1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (Step 2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems (*i.e.,* in this rule as in prior transport rules beginning with CSAPR in 2011, above a contribution threshold of 1 percent of the NAAQS); (Step 3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS through a multifactor analysis; and (Step 4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to the provisions of the rule; additional details regarding the EPA's approach are found in section III of this document.

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

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the 4-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

Based on the EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA finds that the following 23 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

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

[9] Five of these seven states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) currently participate in the Federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update. The FIPs required under this rule amend the existing FIPs for these states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the Federal Group 2 trading program, so the FIPs required in this action constitute new FIPs for these states. The EPA will cease implementation of the state Group 2 trading programs included in the two states' SIPs on the effective date of this rule.

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

[11] These 2 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, and August 3, 2027, for areas classified as Serious nonattainment. *See* 83 FR 25776.

[12] The EPA performed air quality modeling for 2032 in the proposed rulemaking, but did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3. The modeling of 2032 done at proposal using the 2016v2 platform does not constitute or represent any final agency determinations respecting air quality conditions or regulatory judgments with respect to good neighbor obligations or any other CAA requirements.

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

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

Based on the air quality analysis presented in section IV of this document, the EPA finds that, with the exception of Alabama, Minnesota, and Wisconsin, the states found linked in 2023 will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season. As a result, the EPA's evaluation of significantly contributing emissions at Step 3 for Alabama, Minnesota, and Wisconsin is limited to emissions reductions achievable by the 2023 and 2024 ozone seasons.

At the third step of the 4-step framework, the EPA applied a multifactor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that "significantly" contribute to downwind nonattainment or maintenance receptors. The EPA is applying the multifactor test described in section V.A of this document to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,[14] as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in 2023 and future years where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NO_X emissions control technologies: (1) fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in section V of this document and supported by the "Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Final Rule TSD" (Mar. 2023), hereinafter referred to as the EGU NO_X Mitigation Strategies Final Rule TSD, included in the docket for this action, the EPA determines that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NO_X emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NO_X combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. *See* section V.B.1 of this document for a full discussion of EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NO_X emissions reduction potential from EGUs—among the uniform mitigation measures assessed for the covered region—and the most corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA is making a finding that the required controls provide cost-effective reductions of NO_X emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in the EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NO_X SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[15] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

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

In this rulemaking, the EPA is addressing good neighbor obligations for the more protective 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in downwind states under that NAAQS. As further discussed in section V of this document, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. In this rule, the EPA is requiring emissions performance levels for EGU NO_X control strategies commensurate with those determined to be necessary in the NO_X SIP Call and CAIR.

Based on the Step 3 analysis described in section V of this document, the EPA finds that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 22 states linked to downwind

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

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

nonattainment or maintenance in 2023 (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin). For 19 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, for the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact in providing ozone air quality improvements in affected downwind states. Once the EPA identified the industries, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[16] [17] This information helped shape the proposal and final rule. To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved SIPs, consent decrees, and permit limits. That evaluation is detailed in the ''Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Dec. 2021), hereinafter referred to as the Proposed Non-EGU Sectors TSD, prepared for the proposed FIP.[18]

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

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to evaluate the air quality improvements anticipated to result from the implementation of the selected EGU and non-EGU emissions reduction strategies. See section V.D of this document.[20] We also used AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is a less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb) to all of linked receptors. The EPA's over-control analysis, discussed in section V.D.4 of this document, shows that the control stringencies for EGU and non-EGU sources in this final rule do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for any linked upwind state.

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

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

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

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

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

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

our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 23 upwind states subject to EGU and non-EGU emissions reductions requirements under the rule. For additional details about the multi-factor test and the over-control analysis, *see* the document titled ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, Ozone Transport Policy Analysis Proposed Rule TSD'' (Mar. 2023), hereinafter referred to as Ozone Transport Policy Analysis Final Rule TSD, included in the docket for this rulemaking.

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

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

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

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

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

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

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

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

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

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

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

The budget-setting methodology that the EPA will use to determine dynamic budgets for each control period starting with 2026 is an extension of the methodology used to determine the preset budgets and will be used routinely to determine emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined. The stringency of the dynamic emissions budgets will simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. As already noted, for the control periods in which both preset budgets and dynamic budgets are determined for a state (*i.e.,* 2026 through 2029), the state's dynamic budget will apply only if it is higher than the state's preset budget. *See* section VI.B of this document for additional discussion of the EPA's method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

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

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

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

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

The backstop daily emissions rates work in tandem with the ozone season emissions budgets to ensure the elimination of significant contribution as determined at Step 3 is maintained over time and more consistently throughout each ozone season. They will offer downwind receptor areas a necessary measure of assurance that they will be protected on a daily basis during the ozone season by more continuous and consistent operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[23] In addition to maintaining a mass-based seasonal requirement, this rule will achieve a much more consistent level of emissions control in line with our Step 3 determination of significant contribution while maintaining compliance flexibility consistent with that determination. These trading program improvements will promote consistent emissions control performance across the power sector in the linked upwind states, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

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

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

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

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

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

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

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

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

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

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

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

Furnace type	NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

TABLE I.B–6—SUMMARY OF NO_X EMISSIONS LIMITS FOR BOILERS IN IRON AND STEEL AND FERROALLOY MANUFACTURING, METAL ORE MINING, BASIC CHEMICAL MANUFACTURING, PETROLEUM AND COAL PRODUCTS MANUFACTURING, AND PULP, PAPER, AND PAPERBOARD MILLS

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

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

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

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

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

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this final rule is presented in Table I.C–1. Table I.C–1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A–4, of the health and climate benefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2023. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the final rule. These results present an incomplete overview of the effects of the rule because important categories of benefits—including benefits from reducing other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than this table reflects.

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

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

	3% Discount rate	7% Discount rate
Present Value:		
Health Benefits [b]	$200,000	$130,000
Climate Benefits [c]	15,000	15,000
Compliance Costs [d]	14,000	9,400
Net Benefits	200,000	140,000
Equivalent Annualized Value:		
Health Benefits	13,000	12,000
Climate Benefits	970	970
Compliance Costs	910	770
Net Benefits	13,000	12,000

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

[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in ozone and $PM_{2.5}$ concentrations. The health benefits are associated with two point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table.

[c] Climate benefits are calculated using four different estimates of the social cost of carbon ($SC–CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average $SC–CO_2$ at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

[d] The costs presented in this table are consistent with the costs presented in Chapter 4 of the *Regulatory Impact Analysis (RIA).* To estimate these annualized costs for EGUs, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

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

II. General Information

A. Does this action apply to me?

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

TABLE II.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Metal Ore Mining	2122
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221
Solid Waste Combustors and Incinerators	562213

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this rule. Other types of entities not listed in the table could also be regulated. To determine whether your EGU entity is regulated by this rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which are unchanged in this rule. If you have questions regarding the applicability of this rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

overcontrol are not proven through as-applied, particularized challenges, and they are premised on an incorrect understanding of the CAA and the relevant case law. The Agency rejects the contention that it must somehow provide in the present FIP action for a relaxation in the stringency of the Step 4 implementation program and thus allow for the recurrence of pollution that we have found here, in this action, significantly contributes to downwind ozone nonattainment and maintenance problems.

VI. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This action will ensure that emissions reductions necessary to eliminate significant contribution will be achieved "as expeditiously as practicable" and no later than the downwind attainment dates except where compliance by those dates is not possible. *See* CAA section 181(a); *Wisconsin,* 938 F.3d at 318–20. The timing of this action will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season for the covered states, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date will take effect as expeditiously as practicable. Emissions reductions commensurate with SCR mitigation measures for EGUs will start in 2026 and be fully implemented by 2027. Emissions reductions through the mitigation measures for industrial sources will generally go into effect in 2026; however, as explained in section VI.C of this document, we have provided for case-by-case extensions of up to one year based on a demonstration of necessity (with the potential for up to an additional two years based on a further demonstration). The full suite of emissions reductions is generally anticipated to take effect by the 2027 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This rule constitutes a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered; the EPA does not anticipate further rulemaking to address good neighbor obligations under this NAAQS will be required for these states with the finalization of this rule.

EPA's determinations regarding the timing of this rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times that, under the terms of the Good Neighbor Provision, upwind states must eliminate their significant contributions to downwind areas "consistent with the provisions of [title I of the Act]," including those provisions setting attainment deadlines for downwind areas.[259] In *North Carolina,* the D.C. Circuit found the 2015 compliance deadline that the EPA had established in CAIR unlawful in light of the downwind nonattainment areas' 2010 deadline for attaining the 1997 NAAQS for ozone and $PM_{2.5}$.[260] Similarly, in *Wisconsin,* the Court found the CSAPR Update unlawful to the extent it allowed upwind states to continue their significant contributions to downwind air quality problems beyond the downwind states' statutory deadlines for attaining the 2008 ozone NAAQS.[261] In *Maryland,* the Court found the EPA's selection of a 2023 analysis year in evaluating state petitions submitted under CAA section 126 unlawful in light of the downwind Marginal nonattainment areas' 2021 deadline for attaining the 2015 ozone NAAQS.[262] The Court noted in *Wisconsin* that the statutory command—that compliance with the Good Neighbor Provision must be achieved in a manner "consistent with" title I of the CAA—may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, "under particular circumstances and upon a sufficient showing of necessity," but concluded that "[a]ny such deviation would need to be rooted in Title I's framework" and would need to "provide a sufficient level of protection to downwind States."[263]

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

The near-term EGU control stringencies and corresponding reductions in this rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the portion of full remedy reductions related to post combustion control installation identified in sections V.B through V.D of this document are not yet available. The EGU NO_X mitigation strategies available during these initial 3 years are the optimization of existing post-combustion controls (SCRs and SNCRs) and combustion control upgrades. As described in sections V.B through V.D of this document and in accompanying TSDs, these mitigation measures can be implemented in under two months in the case of existing control optimization and in 6 months in the case of combustion control upgrades. These timing assumptions account for planning, procurement, and any physical or structural modification necessary. The EPA provides significant historical data, including the implementation of the most recent Revised CSAPR Update, as well as engineering studies and input factor analysis documenting the feasibility of these timing assumptions. However, these timing assumptions are representative of fleet averages, and the EPA has noted that some units will likely overperform their installation timing assumptions, while others may have unit configuration or operational considerations that result in their underperforming these timing assumptions. As in prior interstate transport rules, the EPA is implementing these EGU reductions through a trading program approach. The trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions.

However, starting in 2024, as described in section VI.B.7 of this document, unit-specific backstop daily emissions rates are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions through state emissions budgets starting in 2023 while imposing the unit-specific backstop emissions rates in 2024 achieves the necessary environmental

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

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

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

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

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

performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding daily operation of optimized SCRs.

Additionally, as in prior rules, the EPA assumes combustion control upgrade implementation may take up to 6 months. In the Revised CSAPR Update, covering 12 of the 22 states for which emissions reduction requirements for EGUs are established under this action, the EPA finalized the rule in March of 2021 and thus did not require these combustion control-based emissions reductions in ozone-season state emissions budgets until 2022 (year two of that program).[264] The EPA is applying the same timing assumption regarding combustion control upgrades for this rulemaking. Given the same relationship here between the date of final action and the year one ozone season, the EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until year two (*i.e.,* the 2024 ozone season). Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for all covered states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade is included and reflected in those state budgets beginning in 2024—which means EGUs in those states have even more time than the 14 months between finalization of this rule and the 2024 ozone season if they started any planning or installation earlier in response to the Revised CSAPR Update.

2. 2026 and Later Years: EGU and Stationary Industrial Source NO_X Reductions Beginning in 2026

The EPA finds that it is not possible to implement all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date. In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is aligning its analysis and implementation of the emissions reductions addressing significant contribution from EGU and non-EGU sources that require relatively longer lead time at a sectoral scale with the 2026 ozone season. The 2026 ozone season is the last full ozone season that precedes the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[265] The EPA proposed to require compliance with all of the remaining EGU and non-EGU control requirements beginning in the 2026 ozone season. The EPA continues to find 2026 to be the relevant analytic year for purposes of its Step 3 analysis, including its analysis of overcontrol, as discussed in section V.D.4 of this document. However, many commenters argued that full implementation of the EGU and industrial source control strategies is not feasible for every source by the 2026 ozone season. The EPA addresses these technical comments specifically in sections V.B and VI.C of this document. The EPA also commissioned a study to develop a better understanding of the time needed for installation of emissions controls for the industrial sector units covered in this rule, which is included in the docket and discussed in section VI.A.2.b of this document. While the EPA does not agree with all of the commenters' assertions regarding the time they claim is needed for control installation, in other respects the concerns raised were sufficient to justify some adjustments to the compliance schedule for the final rule. We have provided for the emissions reductions commensurate with assumed EGU post-combustion emissions control retrofits to be phased in over the 2026 and 2027 ozone season emissions budgets, and we have provided a process in the final regulations for individual non-EGU industrial sources to seek limited compliance extensions extending no later than 2029 based on a case-by-case demonstration of necessity. This compliance schedule delivers substantial emissions reductions in the 2026 and 2027 ozone seasons and before the 2027 Serious area attainment date, and it only allows compliance extensions beyond that attainment date based on a rigorous, source-specific demonstration of need for the additional time.[266]

The timing of this final rule provides three to four years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the start of the 2026 and 2027 ozone seasons. In addition, the publication of the proposal provided roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning (steps that can be taken prior to any capital investment) to be prepared to meet this implementation timetable.

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

For example, section 126 of the CAA authorizes a downwind state or tribe to petition the EPA for a finding that emissions from "any major source or group of stationary sources" in an upwind state contribute significantly to nonattainment in, or interfere with maintenance by, the downwind state. If the EPA makes a finding that a major source or a group of stationary sources emits or would emit pollutants in violation of the relevant prohibition in CAA section 110(a)(2)(D), the source(s) must shut down within three months from the finding unless the EPA directly regulates the source(s) by establishing emissions limitations and a compliance schedule extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as practicable.[267] Thus, in the provision that allows for direct Federal regulation of sources violating the good neighbor provision, Congress established three years as the maximum amount of time available from a final rule to when emissions reductions need to be achieved at the relevant source or group of sources. Because this action is not taken under CAA section 126(c), the mandatory timeframe for implementation of emissions controls

[264] 86 FR 23093.

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

[266] While we generally use the term "necessity" to describe the showing that non-EGU facilities must meet in seeking compliance extensions, the elements for this showing are designed to allow the EPA to make a judgment that comports with the standard of "impossibility" established in case law such as *Wisconsin.* In other words, the "necessity" for additional time is effectively a showing by the source that it would be "impossible" for it to meet the compliance deadline.

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

under that provision is not directly applicable, but it is informative.

In response to arguments from sources that more time than has been provided in the final rule is necessary, this provision strongly indicates that allowing time beyond a three-year period must be based on a substantial showing of impossibility. Our analysis based on comments and considering additional information is that the additional time we have provided in the final rule is both justified and sufficient in light of the statutory objective of expeditious compliance.

Additionally, for ozone nonattainment areas classified as Moderate or higher, the CAA requires states to implement RACT requirements less than three years after the statutory deadline for submitting these measures to the EPA.[268] Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO_X sources as expeditiously as practicable but no later than May 31, 1995, approximately 30 months after the November 15, 1992, deadline for submitting RACT SIP revisions. For purposes of the 2015 ozone NAAQS, the EPA has interpreted these provisions to require implementation of RACT SIP revisions as expeditiously as practicable but no later than January 1 of the fifth year after the effective date of designation, which is less than three years after the deadline for submitting RACT SIP revisions.[269] For areas initially designated nonattainment with a Moderate or higher classification effective August 3, 2018 (83 FR 25776), that implementation deadline falls on January 1, 2023, approximately 29 months after the August 3, 2020 submission deadline.[270] Moderate ozone nonattainment areas must also implement all reasonably available control measures (including RACT) needed for expeditious attainment within three years after the statutory deadline for states to submit these measures to the EPA as part of a Moderate area attainment demonstration.[271] Nonattainment areas for the 2015 ozone NAAQS that were reclassified to Moderate nonattainment in October 2022 face this same regulatory schedule, meaning that their sources are required to implement RACT controls in 2023. With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899 (Oct. 7, 2022). Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* In the October 2022 final rulemaking EPA made determinations that certain Marginal areas failed to attain by the attainment date, reclassified those areas to Moderate, and established SIP submission deadlines and RACM and RACT implementation deadlines. EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. *See* 87 FR 60897, 60900. The implementation deadline for RACM and RACT is also January 1, 2023. *Id.*

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA includes in this rule, as well as the types of emissions control technologies on which the EPA bases the emissions limitations that would take effect for the 2026 and 2027 ozone seasons, generally are consistent with the scope and stringency of RACT requirements for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.[272] Thus, the timing Congress allotted for sources in downwind states to come into compliance with RACT requirements bears directly on the amount of time that should be allotted here and indicates, as does CAA section 126, that three years is an outer limit on the time that should be given sources to come into compliance where possible. In light of the January 1, 2023, deadline for implementation of RACT in Moderate nonattainment areas, the EPA finds that a May 1, 2026 deadline for full implementation of the emissions control requirements in this final rule would generally provide adequate time for any individual source to install the necessary controls, barring the circumstances of necessity discussed further in this section.

Finally, with respect to emissions standards for hazardous air pollutants, section 112(i)(3) of the CAA requires the EPA to establish compliance dates for each category or subcategory of existing sources subject to an emissions standard that "provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard," with limited exceptions. CAA section 112(i)(3)(B) authorizes the EPA to grant an extension of up to 1 additional year for an existing source to comply with emissions standards "if such additional period is necessary for the installation of controls," and sections 112(i)(4) through (7) provide for limited compliance extensions where other conditions are met.[273] Here again, where Congress was concerned with addressing emissions of pollutants that impact public health, a 3-year time period was allotted as the time needed for existing sources to come into compliance where possible. As discussed further in section VI.A.2.b of this document, the process for obtaining a compliance extension for industrial sources in this rule is generally modeled on 40 CFR 63.6(i)(3), which implements

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

[269] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation) and 40 CFR 51.1312(a)(3)(i) (requiring implementation of RACT SIP revisions as expeditiously as practicable, but no later than January 1 of the fifth year after the effective date of designation). For reclassified areas, states must implement RACT SIP revisions as expeditiously as practicable, but no later than the start of the attainment year ozone season associated with the area's new attainment deadline, or January 1 of the third year after the associated SIP revision submittal deadline, whichever is earlier; or the deadline established by the Administrator in the final action issuing the area reclassification. 40 CFR 51.1312(a)(3)(ii); *see* also 83 FR 62989, 63012–63014.

[270] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

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

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

[273] *See, e.g.,* CAA section 112(i)(4), which provides for limited compliance extensions granted by the President based on national security interests.

the extension provision for existing sources under CAA section 112(i)(3)(B).

All of these statutory timeframes for implementation of new control requirements on existing stationary sources indicate that Congress considered 3 years to be not only a sufficient amount of time but an upper bound of time allowable (barring instances of impossibility) for existing stationary sources to install or begin the installation of pollution controls as necessary for expeditious attainment, to eliminate prohibited interstate transport of pollutants, and to protect public health.

Further, the EPA notes that, given the number of years that have passed since EPA's promulgation of the 2015 ozone NAAQS and related nonattainment area designations in 2018, and in light of the *Maryland* court's holding that good neighbor obligations for the 2015 ozone NAAQS should have been implemented by the Marginal area attainment date in 2021,[274] the implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to NO_X emissions control in this rule have continued to operate for several years without the controls necessary to eliminate their significant contribution to ongoing and persistent ozone nonattainment and maintenance problems in other states. Under these circumstances, we find it reasonable to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in section V.B.1.b of this document beginning in the 2026 ozone season (with full implementation by the 2027 ozone season for EGUs, and the availability of source-specific extensions based on a demonstration of necessity for non-EGUs).

As the D.C. Circuit noted in *Wisconsin,* the good neighbor provision requires upwind states to ''eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines'' in the downwind states, even where those attainment deadlines occur before EPA's statutory deadline under CAA section 110(c) to promulgate a FIP.[275]

Referencing the Supreme Court's description of the attainment deadlines as ''the heart'' of the CAA, the *Wisconsin* court noted that some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.''[276]

For the reasons provided in the following sub-sections, the EPA finds that installation of certain EGU controls and all non-EGU controls is not possible by the Moderate area attainment date for the 2015 ozone NAAQS (*i.e.,* August 3, 2024),[277] and, for certain sources, may not be possible by the 2026 ozone season or even the August 3, 2027, Serious area attainment date. While the EPA's technical analysis demonstrates that for any individual source, control installation could be accomplished by the start of the 2026 ozone season, in light of the scope of this rule coupled with current information on the present economic capacity of sources, control-installation vendors, and associated markets for labor and material, it is the EPA's judgment that a three-year timeframe is not possible for all sources subject to this rule collectively to come into compliance. Therefore, additional time beyond 2026 will be allowed for certain facilities in recognition of these constraints on the processes needed for installation of controls across all of the covered sources.

a. EGU Schedule for 2026 and Later Years

As discussed in sections V.B through V.D of this document, significant emissions reduction potential exists and is included in EPA's quantification of significant contribution based on the potential to install post-combustion controls (SCR and SNCRs) at EGUs. However, as discussed in detail in those sections, the assumption for installation of this technology on a region-wide scale is 36–48 months in this final rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA finds that these emissions reductions are not available any earlier than the 2026 compliance period. Starting in 2026, state emissions budgets will reflect full implementation of assumed SNCR mitigation measures and implementation of half the emissions reduction potential identified for assumed SCR mitigation measures. For each year in 2027 and beyond, state emissions budgets include all of the emissions reductions commensurate with these post-combustion control technologies identified for covered units in Step 3. The EPA notes that similar compliance schedules and post-combustion control retrofit installations have been realized successfully in prior programs allowing similar timeframes. Subsequent to the NO_X SIP Call and the parallel Finding of Significant Contribution and Rulemaking on Section 126 Petitions (which became effective December 28, 1998, and February 17, 2000, respectively[278]), nearly 19 GW of SCR retrofit came online in 2002 and another 42 GW of SCR retrofit came online for steam boilers in 2003, illustrating that a considerable volume of SCR retrofit capacity is possible within a 36-month period.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of assumed SCR installation would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that many of the remaining coal units lacking SCR pose more site-specific installation challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA is making several changes in this final rule to address these concerns. First, EPA is phasing in emissions reductions commensurate with assumed SCR installations consistent with a 36-to-48-month time frame in this final rule, instead of a 36-month time frame as proposed. EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states. This phase-in approach to implementing SCR retrofit reduction potential over a three to four year period is in response to comments, including those from third-party full-service engineering firms. These commenters highlighted that while the

[274] 958 F.3d at 1203–1204 (remanding the EPA denial of section 126 petition based on the EPA analysis of downwind air quality in 2023 rather than 2021, the year containing the Marginal area attainment date).

[275] 938 F.3d at 317–318. For example, the court observed that the EPA may shorten the deadline for SIP submissions under CAA section 110(a)(1) and may issue FIPs soon thereafter under CAA section 110(c)(1), to align the upwind states' deadline for satisfying good neighbor obligations with the downwind states' deadline for attaining the NAAQS. *Id.* at 318.

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

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

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

proposed 36-month time frame is viable at the plant level, it would be "very unlikely" that the collective volume of SCR capacity could be installed in a three-year time frame based on a variety of factors. First, the commenters identified constraints on labor needed to retrofit 32 GW of capacity, highlighting that the Bureau of Labor and Statistics projects that there will be a decline in boilermaker employment over the decade and that the Associated Builders and Contractors (ABC) identifies the need for 650,000 additional skilled craft professionals on top of the normal hiring pace to meet the economy-wide demand created by infrastructure investment and other clean energy projects (*e.g.,* carbon capture and storage). They highlighted the decline in companies serving this type of large-scale retrofit project as the lack of new coal units and the retirement of coal units has curtailed activity in this area over the past five years. They also identified supply bottlenecks for key SCR components that would slow the ability to implement a large volume of SCR within 3 years, affecting electrical conduits, transformers, piping, structural and plate steel, and wire (with temporary price increases ranging from 30 percent to 200 percent). Finally, commenters note that site-specific conditions can make retrofits for individual units a lengthier process than historical averages (*e.g.,* under prior rules more accommodating sites retrofitted first) and that four years may be necessary for some projects, accordingly. EPA found the technical justification submitted in comment consistent with its prior assessments that a range of 39–48 months is appropriate for SCR-retrofit timing within regional-scale programs.[279] Therefore, EPA is adjusting the timeframe to still incentivize these reductions by the attainment date while accommodating the potential for some SCR retrofits to require between 36–48 months for installation.

Some commenters requested more than 48 months for SCR installation based on past projects that took five or more years. EPA disagrees with these commenters for two reasons. First, while EPA is identifying SCR retrofit potential to define significant contribution at Step 3, the rule only requires emissions reductions commensurate with that technology, implemented through a trading program, meaning that operators of EGUs eligible for SCR retrofit may pursue a variety of strategies for reducing emissions. Such compliance flexibility will accommodate extreme or unique circumstances in which a desired SCR retrofit is not achieved by the 2027 ozone season, although EPA finds such a circumstance exceedingly unlikely. Second, the historical examples that exceeded 48 months do not necessarily demonstrate that such projects are impossible to execute in less than 48 months, but rather that they can extend beyond that timeframe if no requirements or incentives are in place for a faster installation. As the D.C. Circuit has recognized, historical data on the amount of time sources have taken to install pollution controls do not in themselves establish the minimum amount of time in which those controls could be installed if sources are subject to a legal mandate to do so. *See Wisconsin,* 938 F.3d at 330 ("[A]ll those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.").

b. Non-EGU or Industrial Source Schedule for 2026 and Later Years

The EPA proposed to require that all emissions reductions associated with the requirements for non-EGU industrial sources go into effect by the start of the 2026 ozone season, but also requested comment on its control-installation timing estimates for non-EGUs and requested comment on the possibility of providing for limited compliance extensions based on a showing of necessity. *See* 87 FR 20104–05.

Comment: The EPA received numerous comments regarding the inability of various non-EGU industries to install controls to comply with the emissions limits by 2026. Specifically, commenters raised concerns regarding the ability to meet these deadlines due to the ongoing geopolitical instability triggered by the war in Ukraine, COVID–19 pandemic-driven disruptions, and supply chain delays and shortages. Commenters also claimed that the EPA's three-year installation timeframe for non-EGUs does not account for the time needed to obtain necessary permits. Commenters stated that even where controls are feasible for a source, some sources would need to shut down due to their inability to install controls by 2026 and requested that the EPA provide additional time for sources to come into compliance. Commenters from multiple non-EGU industries stated that the proposed applicability criteria will require controls to be installed on thousands of non-EGU emissions units. Because of the number of emissions units, commenters raised concerns with permitting delays and the unavailability of skilled labor and necessary components. Commenters suggested various timelines for control installation timing ranging from one additional year to seven years. Other commenters asserted that the data supported the conclusion that all non-EGU sources, or at least some non-EGU sources, could install controls by 2026 or earlier, and that EPA has a legal obligation to impose good neighbor requirements as expeditiously as practicable by such sources, including earlier than 2026 if possible.

Response: After reviewing the information received during the public comment period and the additional information presented in the Non-EGU Control Installation Timing Report, the EPA has concluded that the majority of non-EGUs can install and operate the required controls by the 2026 ozone season. For the non-EGU control requirements on which the EPA has based its Step 3 findings as described in section V of this document, the emissions limits will generally go into effect starting with the 2026 ozone season (except where an individual source qualifies for a limited extension of time to comply based on a specific demonstration of necessity, as described in this section). The EPA finds that meeting the emissions limitations of this final rule through installation of necessary controls by an ozone season before 2026 is not expected to be possible for the industrial sources covered by this final rule.

The EPA recognizes that labor shortages, supply shortages, or other circumstances beyond the control of source owner/operators may, in some cases, render compliance by 2026 impossible for a particular industrial source. Therefore, the final rule contains provisions allowing source owner/operators to request limited compliance extensions based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of a source may initially apply for an extension of up to one year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance no later than the 2027 ozone season. The EPA may grant an additional case-based extension of up to two additional years for full compliance, where specific criteria are met.

The EPA initiated a study to examine the time necessary to install the potential controls identified in the final rule's cost analysis for all of the non-EGU industries subject to the final rule, including SNCR, low NO_X burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/advanced selective noncatalytic reduction

[279] 86 FR 23102.

(ASNCR). The resulting report, which we refer to as the ''Non-EGU Control Installation Timing Report,'' identified a range of estimated installation times with minimum estimated installation times ranging from 6–27 months without any supply chain delays and 6–40 months with potential supply chain delays depending on the industry.[280] The Non-EGU Control Installation Timing Report also identified maximum estimated installation times ranging from 12–28 months without any supply chain delays and 12–72 months with potential supply chain delays depending on the industry. As indicated in the Non-EGU Control Installation Timing Report, the installation of layered combustion and NSCR control technology, in particular, could take between 9 and 72 months depending on supply chain delays.[281] The report also indicated that permitting processes may take 6 to 12 months but noted that these processes typically can proceed concurrent with other steps of the installation process.[282]

We find that the potential time needed for permitting processes is generally unlikely to significantly affect installation timeframes of at least three years given that a source that has three or more years to comply is expected, in most cases, to have adequate time to apply for and secure the necessary permits during that time. Permitting processes may, however, impact shorter installation times ranging from 12–28 months. Given the 12–28 month estimate for minimum and maximum installation times without supply chain delays and permitting timeframes typically ranging from 6–12 months, the EPA finds that the controls for non-EGU sources needed to comply with this final rule are generally not expected to be installed significantly before the 2026 ozone season.

Generally, the Non-EGU Control Installation Timing Report indicated that all non-EGU unit types subject to the final rule could install controls within 28 months if there are no supply chain delays. Thus, the Non-EGU Control Installation Timing Report confirms that for any individual facility, meeting the emissions limitations of this final rule through installation of controls can be completed by the start of the 2026 ozone season. It is only when the number of units in the U.S. potentially affected by the rule is taken into account, coupled with broader considerations of economic capacity including current information on supply-chain delays, that the potential need for additional time beyond 2026 becomes a possibility. Under ideal economic conditions (*i.e.,* no supply-chain delays or other constraints), affected units are estimated to be capable to install both combustion and post-combustion controls before the 2026 ozone season. Many commenters, however, provided information on installation timing estimates based on current supply chain delays and labor constraints. These commenters generally stated that installation of the necessary controls for some units would take longer than three years if supply chain delays similar to those that have occurred over the past few years continue. The Non-EGU Control Installation Timing Report reflected this information, together with additional information gathered from pollution control vendors, to develop ranges of estimates of possible installation times given current (*i.e.,* 2022) labor market conditions and material supplies. The Non-EGU Control Installation Timing Report also discussed how the installation and optimization of post-combustion controls over a similar timeframe at both EGUs and non-EGUs subject to this final rule would, considered cumulatively, potentially affect the installation timing needs of the covered non-EGU sources.

Based on information provided by commenters and vendors, the Non-EGU Control Installation Timing Report indicated that if current supply chain delays continue, control installations could take as long as 61 months for most non-EGU industries and possibly as long as 64–112 months in difficult cases. Notably, however, the conclusions in the Non-EGU Control Installation Timing Report reflect three key assumptions that could result in the relatively lengthy timing estimates at the outer end of this range: (1) the current state of supply chain delays and disruptions would continue without any increase in labor supply, materials, or reduction in fabrication timing; (2) the labor and materials markets would not adjust in response to this rule in the timeframe needed to meet the increased demand for control installations; and (3) the Report was unable to account for some of the flexibilities built into the final rule that will allow owners and operators to install controls on the most cost-effective units with shorter installation times.

As presented in the Non-EGU Control Installation Timing Report, supply chain delays and disruptions have generally been lessening since they peaked in 2020 during the COVID–19 pandemic, and many economic indicators have showed some improvement towards pre-pandemic levels, including freight transportation, inventory to sales ratios, interstate miles traveled, U.S. goods imports, and supply chain indices.[283] If these economic indicators continue to improve and the availability of fabricators and materials continues to trend upward, the control timing estimates identified in the Non-EGU Control Installation Timing Report could prove to be overstated for some industries and control technologies. In addition, the Non-EGU Control Installation Timing Report did not account for the labor and supply market adjustments that would be anticipated to occur to meet increased demand for control technologies and related materials and labor over the next several years in response to the rule. *Cf. Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes [of elongated control installation times] show is that installation can drag on when companies are unconstrained by the ticking clock of the law.''). For example, some of the longer installation timeframes identified in the Non-EGU Control Installation Timing Report are based on assumed limits on the current availability of skilled labor needed to install combustion controls and post combustion controls. If the market adjusts in response to increasing demand for this type of skilled labor in the timeframe needed for compliance (*e.g.,* there is an increase in boilermaker and engine controls labor), the installation timing estimates in the Non-EGU Control Installation Timing Report again could be overstated.

The Non-EGU Control Installation Timing Report also did not account for flexibilities provided in this final rule that will enable owners and operators of certain affected units to identify the most cost-effective and efficient means for installing any necessary controls. For example, one concern highlighted by commenters was the amount of time necessary to install controls on engines that have been in operation for 50 or more years. The requirements that we are finalizing for engines in the Pipeline Transportation of Natural Gas industry include an exemption for emergency engines and provisions allowing source owner/operators to request the EPA approval of facility-wide emissions averaging plans, both of which enable owners and operators of affected units to take costs, installation timing needs,

[280] *See generally* SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023) (''Non-EGU Control Installation Timing Report'').

[281] *See* Non-EGU Control Installation Timing Report, Executive Summary (March 14, 2023).

[282] Id. at Section 5.6.

[283] Id. at Section 6.1.

and other considerations into account in deciding which engines to control.

In response to industry concern about the number and size of units captured by the proposed applicability criteria, the EPA has made several changes to the applicability criteria in the final rule to focus the control requirements on impactful non-EGU units. As explained further in section VI.C of this document, the EPA is establishing exemptions for low-use boilers and engines where it would not be cost-effective to require controls at this time. Finally, as discussed in section VI.C.3 of this document, the EPA is not finalizing the proposed requirements for most emissions unit types in the Iron and Steel Mills and Ferroalloy Manufacturing industry given the EPA does not currently have a sufficient technical basis for finalizing those proposed requirements. These changes reduce the number of non-EGU units that will actually need to install controls and should reduce the strain on the labor and supply chain and permitting processes. For example, for engines, the EPA estimates that the facility-wide emissions averaging provision would, in many cases, allow facilities to install controls on only one-third of their engines, on average (see section VI.C.1 of this document for further discussion).

Taking all of these considerations into account, the EPA finds that the outer range of timing estimates presented in the Non-EGU Control Installation Timing Report generally reflects a conservative set of installation timing estimates and that the factors described previously could result in installation timeframes that fall toward the shorter end of the ranges of time that factor in supply-chain delays or could obviate those supply-chain delay issues entirely.

Based on all of these considerations, the EPA has concluded that three years is generally an adequate amount of time for the non-EGU sources covered by this final rule to install the controls in the 20 states that remain linked in 2026. The EPA also recognizes, however, that some sources may not be able to install controls by the 2026 ozone season despite making good faith efforts to do so, due to the aforementioned supply chain delays or other circumstances entirely beyond the owner or operator's control. Therefore, the final FIPs require compliance with the emissions control requirements for non-EGUs by the beginning of the 2026 ozone season, with limited exceptions based on a showing of necessity for individual sources that meet specific criteria. Where an individual owner or operator submits a satisfactory demonstration that an extension of time to comply is necessary, due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by May 1, 2026, the EPA may determine that installation by 2026 is not possible and thereby grant an extension of up to one year for that source to fully implement the required controls. If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply by the extended compliance date due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by the extended compliance date, the owner or operator may request and the EPA may grant a second extension of up to two additional years for full compliance, where specific criteria are met. This application process is generally in accordance with the concept on which the Agency requested comment in the proposal, *see* 87 FR 20104–05, and is modeled on a similar process provided for industrial sources subject to CAA section 112 NESHAPs, found at 40 CFR 63.6(i)(3).

The EPA intends to grant a request for an initial compliance extension only where a source demonstrates that it has taken all steps possible to install the necessary controls by the applicable compliance date and still cannot comply by the 2026 ozone season, due to circumstances entirely beyond its control. Any request for a compliance extension must be received by the EPA at least 180 days before the May 1, 2026, compliance date. The request must include all information obtained from control technology vendors demonstrating that the necessary controls cannot be installed by the applicable compliance date, any permit(s) secured for the installation of controls or information from the permitting authority on the timeline for issuance of such permit(s) if the source has not yet obtained the required permit(s); and any contracts entered into by the source for the installation of the control technology or an explanation as to why no contract is necessary. The EPA may also consider documentation of a source owner's/operator's plans to shut down a source by the 2027 ozone season in determining whether a source is eligible for a compliance extension. The owner or operator of an affected unit remains subject to the May 1, 2026 compliance date unless and until the Administrator grants a compliance extension.

The EPA intends to grant a request for a second compliance extension beyond 2027 only where a source owner/operator submits updated documentation showing that it is not possible to install and operate controls by the 2027 ozone season, despite all good faith efforts to comply and due to circumstances entirely beyond its control. The request must be received by the EPA at least 180 days before the extended compliance date and must include, at minimum, the same types of information as that required for the initial extension request. The owner or operator of an affected unit remains subject to the initial extended compliance date unless and until the Administrator grants a second compliance extension. A denial will be effective on the date of denial.

As discussed earlier in section VI.A, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only "under particular circumstances and upon a sufficient showing of necessity."[284] This standard is met when, in the EPA's judgment, compliance by the attainment date amounts to an impossibility. The EPA cannot allow a covered industrial source to avoid timely compliance with the emissions control requirements established in this final rule unless the source owner/operator can demonstrate that compliance by the 2026 ozone season is not possible due to circumstances entirely beyond their control. The criteria that must be met to qualify for limited extensions of time to comply are designed to meet this statutory mandate. The EPA anticipates that the majority of the industrial sources covered by this final rule will not qualify for a compliance extension.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA is revising the existing CSAPR NO_X Ozone Season Group 3 Trading Program (the "Group 3 trading program") established in the Revised CSAPR Update both to expand the program's geographic scope and to enhance the program's ability to ensure favorable environmental outcomes. The EPA is using a trading program for EGUs because of the inherently greater flexibility that a trading program can provide relative to more prescriptive, "command-and-control" forms of regulation of sufficient stringency to achieve the necessary emissions reductions. In the electric

[284] *Wisconsin*, 938 F.3d at 316 and 319–320 (noting that any such deviation must be "rooted in Title I's framework" and "provide a sufficient level of protection to downwind States").

power sector, EGUs' extensive interconnectedness and coordination create the ability to shift both electricity production and emissions among units, providing a closely related ability to achieve emissions reductions in part by shifting electricity production from higher-emitting units to lower-emitting or non-emitting units. Thus, while the Step 3 control-stringency determination for EGUs to eliminate significant contribution is based on strategies that do not require generation shifting or reduced utilization of EGUs, the sector's unusual flexibility with respect to how emissions reductions can be achieved makes the flexibility of a trading program particularly useful as a means of lowering the overall costs of obtaining such reductions. In addition, it is essential for the electric power sector to retain short-term operational flexibility sufficient to allow electricity to be produced at all times in the quantities needed to meet demand simultaneously, and the flexibility of a trading program can be helpful in supporting this aspect of the industry as well.

To ensure emissions reductions necessary to eliminate significant contribution are maintained, in this rulemaking, the EPA is making certain enhancements to the current provisions of the Group 3 trading program addressing emissions-control performance by some kinds of individual units that will necessarily reduce the flexibility of the program to some extent for those units. In analyzing significant contribution at Step 3, once a linkage has been established between an upwind state and a downwind receptor, we identify an appropriate set of emissions control strategies, considering cost and other factors, that would eliminate significant contribution from the upwind state without leading to undercontrol or overcontrol at the downwind linked receptors. At Step 4, for EGUs, we develop emissions budgets based on consistent application of the identified strategies to the sources. This level of emission control at each source identified in Step 3 is what the EPA deems to eliminate significant contribution, while the design of emission budgets that successfully implement that level of emission control is determined at Step 4. See section III.B and V.

The trading program enhancements discussed in this section are designed to ensure that sources actually achieve that level of emission control and thereby eliminate significant contribution on a permanent basis at Step 4. The enhancements ensure that the emissions budgets for EGUs continue to secure the level of emission control identified at Step 3 at the sources active in the trading program on a more consistent basis throughout each ozone season than prior transport trading programs (including those that did not provide complete remedies for interstate pollution transport) have required. An alternative form of implementation at Step 4 would be to implement source-specific emissions limitations (*e.g.,* rate-based standards expressed as mass per unit of heat input) reflecting the control strategies identified at Step 3. This is a very common form of implementation for many other CAA requirements and is indeed the manner of implementation selected in this very rulemaking for other affected industrial sources. See sections III.B, V.D.4, and VI.C. But doing so would require loss of the flexibilities inherent in a trading program, inclusive of these enhancements, that facilitate orderly and timely achievement of the required emission reductions in the power sector.

Prior to this rule, the Group 3 trading program has applied to EGUs meeting the program's applicability criteria within the borders of twelve states: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs in these twelve states will continue to participate in the Group 3 trading program as revised in this rulemaking, with some revised provisions taking effect in the 2023 control period and other revised provisions taking effect later as discussed elsewhere in this document. The EPA is expanding the Group 3 trading program's geographic scope to include all of the additional states for which EGU emissions reduction requirements are being established in this rulemaking. Affected EGUs within the borders of seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the "Group 2 trading program")—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 trading program to the revised Group 3 trading program at the beginning of the 2023 control period,[285] and affected EGUs within the borders of the three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period on the effective date of this rule.

As discussed in section VI.B.12.a of this document, because the effective date of the rule will likely be sometime during the 2023 ozone season, special transitional provisions have been developed to allow for efficient administration of the rule's EGU requirements through the Group 3 trading program while not imposing any new substantive obligations on parties prior to the rule's effective date, similar to the transitional provisions implemented under the Revised CSAPR Update.

As is the case for the states already in the Group 3 trading program, for each state added to the program, the set of affected EGUs will include new units as well as existing units and will also include units located in Indian country within the state's borders. Sections VI.B.2 and VI.B.3 of this rule provide additional discussion of the geographic expansion of the Group 3 trading program and the units in the expanded geography that will become subject to the program under the program's existing applicability provisions.

In addition to expanding the Group 3 trading program's geographic scope, the EPA is modifying the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements will adjust the overall quantities of allowances available for compliance in the trading program in each control period so as to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves. First, instead of establishing emissions budgets for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet unknown at the time of the rulemaking, the EPA is revising the trading program regulations to include a dynamic budgeting procedure. Under this procedure, the EPA will calculate emissions budgets for control periods in 2026 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2024 ozone season and following (*e.g.,* for 2026, data from periods through 2024; for 2027, data from periods through 2025; etc.). Through the 2029 control period, the dynamically determined budgets will apply only if they are higher than preset budgets established in the rule. (Associated revisions to the program's variability limits and unit-level allowance allocation procedures will coordinate these provisions with the revised budget-setting procedures.) Second,

[285] Affected EGUs in the three other states currently covered by the Group 2 trading program—Iowa, Kansas, and Tennessee—will continue to participate in that program.

starting with the 2024 control period, the EPA will annually recalibrate the quantity of accumulated banked allowances under the program to prevent the quantity of allowances carried over from each control period to the next from exceeding the target bank level, which would be revised to represent a preset percentage of the sum of the state emissions budgets for each control period. The preset percentage will be 21 percent for control periods through 2029 and 10.5 percent for control periods in 2030 and later years. Together, these enhancements will protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and will better sustain over time the incentives created by the trading program to achieve the degree of emissions control for EGUs that the EPA has determined is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program establish provisions designed to promote more consistent emissions control by individual EGUs within the context of the trading program. First, starting with the 2024 control period for coal-fired EGUs with existing SCR controls and the earlier of the 2030 control period or the control period after which an SCR is installed for other large coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu will apply as a backstop to the seasonal emissions budgets (which are based on an assumed seasonal average emissions rate of 0.08 lb/mmBtu for EGUs with existing SCR controls). Each ton of emissions exceeding a unit's backstop daily emissions rate, after the first 50 such tons, in a given control period will incur a 3-for-1 allowance surrender ratio instead of the usual 1-for-1 allowance surrender ratio. Second, also starting with the 2024 control period, the trading program's existing assurance provisions, which require extra allowance surrenders from sources that are found responsible for contributing to an exceedance of the relevant state's "assurance level" (*i.e.,* typically 121 percent of the state's emissions budget), will be strengthened by the addition of another backstop requirement. Specifically, for any unit equipped with post-combustion controls that is found responsible for contributing to an exceedance of the state's assurance level, the revised regulations will prohibit the unit's seasonal emissions from exceeding by more than 50 tons the emissions that would have resulted if the unit had achieved a seasonal average emissions rate equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest previous seasonal average emissions rate under any CSAPR seasonal NO_X trading program.[286]

These two enhancements are designed to ensure that all individual units with SCR controls have strong incentives to continuously operate and optimize their controls, and also to ensure that all units with post-combustion controls have strong incentives to optimize their emissions performance when a state's assurance level might otherwise be exceeded. These enhancements are generally designed to ensure consistency with the EPA's determination regarding the emissions control stringency needed from EGUs to eliminate significant contribution under the Step 3 multifactor analysis as discussed in section V of this document. Further, these enhancements are designed to provide greater assurance that emissions controls will be operated on all days of the ozone season and therefore necessarily on the days that turn out to be most critical for downwind ozone levels. The EPA expects that promoting more consistently good emissions performance by individual EGUs will better ensure that each state's significant contribution is fully eliminated by this action, *see North Carolina,* 531 F.3d at 919–21. In addition to addressing the statutory requirements of eliminating significant contribution, the EPA anticipates that these enhancements will also deliver public health and environmental benefits to underserved and overburdened communities.

The revisions to the Group 3 trading program being finalized in this rule are very similar to the proposed revisions. The changes from proposal to the set of states covered are driven largely by updates to the air quality modeling performed for the final rule, as described in section IV of this document. The changes from proposal to the trading program enhancements are generally being made in response to comments on the proposal, as discussed in more detail in the remainder of section VI.B of this document.

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

1. Trading Program Background and Overview of Revisions

a. Current CSAPR Trading Program Design Elements and Identified Concerns

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

The EPA currently administers six CSAPR trading programs for EGUs (promulgated in CSAPR, the CSAPR Update, and the Revised CSAPR Update) that differ in the pollutants, geographic regions, and time periods covered and in the levels of stringency, but that otherwise have been nearly identical in their core design elements and their regulatory text.[287] The principal common design elements currently reflected in all of the programs are as follows:

• An "emissions budget" is established for each state for each control period, representing the EPA's quantification of the emissions that would remain under certain projected conditions after elimination of the emissions prohibited by the good neighbor provision under those projected conditions. For each control period of program operation, a quantity of newly issued "allowances" equal to the amount of each state's emissions budget is allocated among the state's sources. (States have options to replace the EPA's default allocations or to institute an auction process.) Total emissions in a given control period from all sources in the program are effectively

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

capped at a level no higher than the total quantity of allowances available for use in the control period, consisting of the sum of all states' emissions budgets for the control period plus any unused allowances carried over from previous control periods as ''banked'' allowances.

- ''Assurance provisions'' in each program establish an ''assurance level'' for each state for each control period, defined as the sum of the state's emissions budget plus a specified ''variability limit.'' The purpose of the assurance provisions is to limit the total emissions from each state's sources in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's mandate that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability. In the event a state's assurance level is exceeded, responsibility for the exceedance is apportioned among the state's sources through a procedure that accounts for the sources' shares of the state's total emissions for the control period as well as the sources' shares of the state's assurance level for the control period.
- At the program's compliance deadlines after each control period, sources are required to hold for surrender specified quantities of allowances. The minimum quantities of allowances that must be surrendered are based on the sources' reported emissions for the control period at a 1-for-1 ratio of allowances to tons of emissions (or 2-for-1 in instances of late compliance). In addition, two more allowances must be surrendered for each ton of emissions exceeding a state's assurance level for a control period, yielding an overall 3-for-1 surrender ratio for those emissions (or 4-for-1 in instances of late compliance). Failure to timely surrender all required allowances is potentially subject to penalties under the CAA's enforcement provisions.
- To continuously incentivize sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, and to promote compliance cost minimization, operational flexibility, and allowance market liquidity, the programs allow trading of allowances—both among sources in the program and with non-source entities—and also let allowances that are unused in one control period be carried over for use in future control periods as banked allowances. Although the CSAPR programs do not limit trading of allowances, and prior to this rule have not limited banking of allowances within a given trading program, the 3-for-1 surrender ratio imposed by the assurance provisions on any emissions exceeding a state's assurance level disincentivizes sources from relying on either in-state banked allowances or net out-of-state purchased allowances to emit over the assurance level.[288]
- Finally, other common design elements ensure program integrity, source accountability, and administrative transparency. Most notably, each unit must monitor and report emissions and operational data in accordance with the provisions of 40 CFR part 75; all allowance allocations or auction results, transfers, and deductions must be properly recorded in the EPA's Allowance Management System; each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account; and comprehensive data on emissions and allowances are made publicly available.

The EPA continues to believe that the historical CSAPR trading program structure established by the common design elements just described has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide to a sector such as the electric power sector where such flexibility is especially useful and valuable. However, the EPA also shares many stakeholders' concerns about whether the historical structure, without enhancements, is capable of adequately addressing states' good neighbor obligations with respect to the 2015 ozone NAAQS in light of the rapidly evolving EGU fleet and the protectiveness and short-term form of the ozone standard. One set of concerns relates to the historically observed tendency under the trading programs for the supply of allowances to grow over time while the demand for allowances falls, reducing allowance prices and eroding the consequent incentives for sources to effectively control their emissions. A second, overlapping set of concerns relates to the general absence of source- or unit-specific emissions reduction requirements, allowing some individual sources to idle or run less optimally existing emissions controls even when a linkage between the sources' state and a receptor persists. For example, certain units in Ohio and Pennsylvania have been found to have operated their controls below target emissions performance levels used for budget setting under the CSAPR Update in the 2019–2021 period, even though the Revised CSAPR Update found that these states remained linked through at least 2021 to receptors for the 2008 ozone NAAQS, and the CSAPR Update itself was only a partial remedy. *See* 86 FR 23071, 23083. While this unit-level behavior may have been permissible under the prior program, emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard. This indicates that the prior program design was not effectively ensuring the elimination of significant contribution.[289]

The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. In an effort to ensure emissions control on critically important highest ozone days, guard against non-operation of emissions controls under a more protective NAAQS, and provide assurance of elimination of significant contribution to downwind areas, while also maintaining appropriate compliance and operational flexibility for EGUs, the EPA in this rule is implementing a suite of enhancements to the trading program. These will help to ensure reductions occur on the highest ozone days commensurate with our Step 3 determinations, in addition to maintaining a mass-based seasonal requirement. To meet the statutory mandate to eliminate significant contribution and interference with

[288] As discussed in section VI.B.6 of this document, while allowance banking has not previously been limited under any of the CSAPR trading programs, limits on the use of banked allowances were included in the earlier NO_X Budget Trading Program in the form of ''flow control'' provisions.

[289] We also observe that these sources' emissions have the potential to impact downwind overburdened communities. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E. The EPA conducted a screening-level analysis to determine whether there may be impacts on overburdened communities resulting from those EGUs receiving backstop emissions rates under this rule. This analysis identified a greater potential for these sources to affect areas of potential concern than the national coal-fired EGU fleet on average. However, this analysis is distinct from the more comprehensive exposure analysis conducted as discussed in section VII of this document and the RIA. In addition, we note that our conclusions regarding the EGU trading program enhancements in this final rule are wholly supportable and justified under the good neighbor provision, even in the absence of any potential benefits to overburdened communities.

maintenance on the critically important days, this combination of provisions will strongly incentivize sources to plan to run controls all season, including on the highest ozone days, while giving reasonable flexibility for occasional operational needs.[290]

In this rulemaking, the EPA is revising the Group 3 trading program to include enhancements designed to address both sets of concerns described previously. The principles guiding the various revisions and the relationships of the revisions to one another are discussed in sections VI.B.1.b and VI.B.1.c of this document. The individual revisions are discussed in more detail in sections VI.B.4 through VI.B.9 of this document.

b. Enhancements To Maintain Selected Control Stringency Over Time

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

i. Revised Emissions Budget-Setting Process

In each of the previous rulemakings establishing CSAPR trading programs, the EPA has evaluated the emissions that could be eliminated through implementation of certain types of emissions control strategies available at various cost thresholds to achieve certain rates of emissions per unit of heat input (*i.e.,* the amount of fuel consumed) and the effects of the resulting emissions reductions on downwind air quality. After determining the emissions control strategies and associated emissions reductions that should be required under the good neighbor provision by considering these factors in a multifactor test at Step 3, the EPA has then for purposes of Step 4 implementation program design projected the amounts of emissions that would remain after the assumed implementation of the selected emissions control strategies at various points in the future and has established the projected remaining amounts of emissions as the state emissions budgets in trading programs.

Projecting the amounts of emissions remaining after implementation of selected emissions controls necessarily requires projections not only for sources' future emissions rates but also for other factors that influence total emissions, notably the composition of the future EGU fleet (*i.e.,* the capacity amounts of different types of sources with different emissions rates) and their future utilization levels (*i.e.,* their heat input). To the extent conditions unfold in practice that differ from the projections made at the time of a rulemaking for these other factors, over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking as consistent with addressing states' good neighbor obligations. Further, projecting EGU fleet composition and utilization beyond the relatively near-term analytic years of 2023 and 2026 given particular attention in this rulemaking has become increasingly challenging in light of the anticipated continued evolution of the electric power sector toward more efficient and cleaner sources of generation, including as driven by incentives provided by the Infrastructure Investment and Jobs Act as well as the Inflation Reduction Act.

A consequence of using a trading program approach with preset emissions budgets that do not keep pace with the trends in EGU fleet composition and heat input is that the preset emissions budgets maintain the supply of allowances at levels that increasingly exceed the emissions that would occur even without implementation of the emissions control strategies used as the basis for determining the emissions budgets, causing decreases in allowance prices and hence the incentives to implement the control strategies. As an example, although the emissions budgets in the CSAPR Update established in 2016 reflected implementation of the emissions control strategy of operating and optimizing existing SCR controls, within four years the EPA found that EGU retirements and changes in utilization not anticipated in EPA's previous budget-setting computations had made it economically attractive for at least some sources to idle or reduce the effectiveness of their existing controls (relying on purchased allowances instead).[291] While the EPA has provided analysis indicating that, on average, sources operate their controls more effectively on high electric demand days, it has also identified cases where units fail to optimize their controls on these days. Downwind states have suggested this type of reduced pollution control performance has occurred on the day and preceding day of an ozone exceedance.[292] [293] While the EPA had previously provided analysis focusing on the year of initial program implementation, when allowance prices were high (*i.e.,* 2017 for the CSAPR Update), to demonstrate that on average, sources operate their controls more effectively on high electric demand days, even in that case it had identified situations where particular units failed to optimize their controls on these days. In later years, when allowance prices had fallen, more sources, including some identified by commenters, had idled or reduced the effectiveness of their controls. Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies identified in the CSAPR Update to eliminate significant contribution to nonattainment and interference with maintenance, despite the fact that the mass-based budgets were being met.

In the Revised CSAPR Update, the EPA took steps to better address the rapid evolution of the EGU fleet, specifically by setting updated emissions budgets for individual future

[290] Deferral of the backstop daily emissions rate for certain EGUs, for reasons discussed in section VI.B.7 of this document, does not alter this finding that this trading program enhancement is an important part of the solution to eliminating significant contribution from EGUs under CAA section 110(a)(2)(D)(i)(I).

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

[292] 86 FR 23117.

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

years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters in that rulemaking requested that the EPA also update the year-by-year emissions budgets to reflect future fleet changes that might become known after the time of the rulemaking, but the EPA declined to do so, in part because no methodology for making future emissions budget adjustments in response to post-rulemaking data had been included in the proposal for the rulemaking.

Based on information available as of December 2022, it appears that the emissions budgets set for the first two control periods covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for those control periods. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources will likely lead to a surplus of allowances after the adjustments end. This prospect for the existing Group 3 trading program should be avoided by the changes being made in this rulemaking. In this rulemaking, besides establishing new preset emissions budgets for the 2023 through 2029 control periods, the EPA is also extending the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely calculate dynamic emissions budgets for each future control period from 2026 on, to be published in the year before that control period, with each dynamic emissions budget generally reflecting the latest available information on the composition and utilization of the EGU fleet at the time that dynamic emissions budget is determined. For the control periods in 2026 through 2029, each state's final emissions budget will be the preset budget determined for the state in this rulemaking except in instances when the dynamic budget determined for the state (and published approximately one year before the control period using the dynamic budget-setting methodology) is higher. For control periods in 2030 and thereafter, the emissions budgets will be the amounts determined for each state in the year before the control period using the dynamic budget-setting methodology.

The current budget-setting methodology established in the Revised CSAPR Update and the revisions being made to that methodology are discussed in detail in section VI.B.4 of this document and the Ozone Transport Policy Analysis Final Rule TSD. To summarize here, the methodology used to determine the preset budgets largely follows the Revised CSAPR Update's emissions budget-setting methodology, which included three primary steps: (1) establishment of a baseline inventory of EGUs adjusted for known retirements and new units, with heat input and emissions rate data for each EGU in the inventory based on recent historical data; (2) adjustment of the baseline data to reflect assumed emissions rate changes resulting from known new controls, known gas conversions, and implementation of the emissions control strategies used to determine states' good neighbor obligations; and (3) application of an increment or decrement to reflect the effect on emissions from projected generation shifting among the units in a state at the emissions reduction cost associated with the selected emissions control strategies. In this rulemaking, the EPA has determined the preset state emissions budgets for the control periods from 2023 through 2029 by using the Revised CSAPR Update's budget-setting methodology, except that the step of that methodology intended to reflect the effects of generation shifting has been eliminated.

The dynamic budget-setting methodology used to determine dynamic state emissions budgets in the year before each control period starting with the 2026 control period is set forth in the revised Group 3 trading program regulations at 40 CFR 97.1010(a). This methodology modifies the Revised CSAPR Update's budget-setting methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, will be updated for each control period using the most recent available reported data in combination with reported data from the four immediately preceding years. For example, in early 2025, using the final data reported for 2020 through 2024, the EPA will update the baseline inventory and heat input data used to determine dynamic state emissions budgets for the 2026 control period.[294] Second, the EPA will not apply an increment or decrement to any state emissions budget for projected generation shifting associated with implementation of the selected control strategies, because any such shifting should already be reflected in the reported heat input data used to update the baseline.

The EPA believes that the revisions to the emissions budget-setting process will substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The dynamic budget-setting methodology will account for the electric power sector's overall trends toward more efficient and cleaner resources, both of which tend to decrease total heat input at affected EGUs, and through 2029 the preset budgets established in the rule will also account for these factors to the extent known. The dynamic budget-setting methodology will also account for other factors that could lead to increased heat input in some states, such as generation shifting from other states or increases in electricity demand caused by rising electrification. The dynamic budget-setting procedure is specified in this final rule's trading program regulations and the computations, which are straightforward, can be performed in a spreadsheet to deliver reliable results. The EPA will provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and will provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the dynamic budgets for each control period by May 1 of the year before the control period to which those dynamic budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2025, of the dynamic emissions budgets that will be calculated for the 2026 control period that starts May 1, 2026. Moreover, as of the issuance of this final rule, stakeholders will know the state-level preset emissions budgets for the 2026–2029 control periods, which serve as floors that will only be supplanted by dynamic budgets calculated for those control periods if such a dynamic budget yields a higher amount of tons than the corresponding preset budget established in this action.

It bears emphasis that the annually updated information used in the dynamic budget-setting computations will concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in those computations. The dynamically determined emissions budget computations for all years will reflect only the specific emissions control

[294] As discussed in section VI.B.4 of this document, the state-level data used to determine the overall state-level heat input for computing a state's dynamic budget will be a three-year average (*e.g.,* 2022–2024 state-level data will be used in 2025 to set the 2026 dynamic budgets). The unit-level data used to determine individual units' shares of the state-level heat input in the computations will be the average of the three highest non-zero heat input amounts for the respective units over the most recent five years (*e.g.,* 2020–2024 unit-level data will be used in 2025 to set the 2026 dynamic budgets).

strategies used to determine states' good neighbor obligations as determined in this rulemaking, along with fixed historical emissions rates for units that are not assumed to implement additional control strategies, thereby ensuring that the annual updates will eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets will simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and will do so more consistently over time than the EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The rule's revisions relating to state emissions budgets and the budget-setting process generally follow the proposal except for two changes we are making in response to comments, specifically: we will use historical data from multiple years rather than a single year in the dynamic budget-setting process, and we are establishing preset emissions budgets for the 2026–2029 control periods such that the dynamic budgets for those control periods will only be imposed where they exceed the corresponding preset budgets finalized in this rule. The rationale for these changes is discussed later in this section as part of the responses to the relevant comments. Details of the final budget-setting methodology and responses to additional comments are discussed further in section VI.B.4 of this document.

The final rule's provisions relating to the determination of state-level variability limits and assurance levels and unit-level allowance allocations are coordinated with the budget-setting methodology. These provisions generally follow the proposal except that the change to the methodology for determining variability limits is implemented starting with the 2023 control period instead of the 2025 control period and the final methodology for determining unit-level allocations of allowances to coal-fired units considers the controlled emissions rate assumptions applicable to the same units in the budget-setting process. Details of these provisions, including the rationales for the changes from proposal, are discussed in sections VI.B.5 and VI.B.9, respectively.

ii. Allowance Bank Recalibration

Besides the levels of the emissions budgets, the second design element of the trading program structure that affects the supply of allowances in each control period, and that consequently also affects the ability of a trading program to maintain the rule's selected control stringency as the EGU fleet evolves over time, is the set of rules concerning the carryover of unused allowances for use in future control periods as banked allowances. As noted previously, trading and banking of allowances in the CSAPR trading programs can serve a variety of purposes: continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. All of these purposes are advanced by rules that allow sources to trade allowances freely (both with other sources and with non-source entities such as brokers). All of these purposes are also advanced by rules that allow unused allowances to be carried over for possible use in future control periods, thereby preserving a value for the unused allowances. However, while the EPA considers it generally advantageous to place as few restrictions on the trading of allowances as possible,[295] unrestricted banking of allowances has a potentially significant disadvantage offsetting its advantages, namely that it allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. With weakened incentives, some operators would be more likely to choose not to continuously operate and optimize their emissions controls, imperiling the ongoing achievement of emissions rate performance consistent with the control strategies defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in section VI.B.6 of this rule, the EPA is revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances that will be carried out in August 2024 and each subsequent August, after the compliance deadline for the control period in the previous year. In each recalibration, the EPA will reset the total quantity of banked allowances for the Group 3 trading program ("Group 3 allowances") held in all Allowance Management System accounts to a level computed as a target percentage of the sum of the state emissions budgets for the current control period. The target percentage will be 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years. The recalibration procedure entails identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the recalibration and then, if the ratio is less than 1.0, multiplying the quantity of banked allowances held in each account by the ratio to identify the appropriate recalibrated amount for the account (rounded to the nearest allowance), and deducting any allowances in the account exceeding the recalibrated amount.

As noted previously, recalibration of the bank for each control period will be carried out in August of that control period. This timing will accommodate the process of deducting allowances for compliance for the previous control period, which cannot be completed before sources' June 1 compliance deadline for the previous control period, and will then provide approximately two additional months for sources to engage in any desired allowance transactions before recalibration occurs. However, data that can be used to estimate the bank recalibration ratio for each control period will be available shortly after the end of the previous control period, and the EPA will use these data to make information on the estimated bank recalibration ratio for each control period publicly available no later than March 1 of the year of that control period, thereby facilitating the ability of affected EGUs to anticipate their ultimate holdings of recalibrated banked allowances to inform their compliance planning for that control season. Affected EGUs will also have several months following the completed bank recalibration in August to transact allowances with other parties as needed

[295] The advantages of trading programs discussed earlier in this section—providing continuous emissions reduction incentives, facilitating compliance cost minimization, and supporting operational flexibility—depend on the existence of a marketplace for purchasing and selling allowances. Broader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing these advantages. The EPA recognizes that unrestricted use of *net* purchased allowances—meaning quantities of purchased allowances that exceed the quantities of allowances sold—by a source or group of sources as an alternative to making emissions reductions can interfere with the achievement of the desired environmental outcome. Therefore, section VI.B.1.c of this document discusses the enhancements to the Group 3 trading program that the EPA is making in this rulemaking to reduce reliance on net purchased allowances by incentivizing or requiring better environmental performance at individual EGUs. However, the concern arises from the *use of an excessive quantity* of net purchased allowances for a particular purpose, not from the existence of a *marketplace* where allowances may be freely bought and sold.

before the allowance transfer deadline of June 1 of the following year.

The EPA believes this revision to the Group 3 trading program's banking provisions establishing an annual bank recalibration process will complement the revisions to the budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods.

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

The final rule's provisions relating to bank recalibration generally follow the proposal except that, in response to comments, the target percentage used to determine the recalibrated bank levels for the 2024–2029 control periods is being set at 21 percent instead of 10.5 percent. The rationale for this change is discussed later in this section as part of the responses to the relevant comments. Details of the bank recalibration provisions are discussed further in section VI.B.6 of this rule.

c. Enhancements To Improve Emissions Performance at Individual Units

The second set of concerns about the structure of the current CSAPR trading programs relates to the general absence of source- or unit-specific emissions reduction requirements. Without such requirements, the programs affect individual sources' emissions performance only to the extent that the incentives created by allowance prices are high enough relative to the costs of the sources' various emissions control opportunities. In circumstances where the incentives to control emissions are insufficient, some individual sources even idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard.

This EPA intends that the trading program enhancements described in section VI.B.1.b of this rule will improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance will be achieved by all participating units without the need for additional requirements to be imposed at the level of individual units. However, because obtaining needed emissions performance at individual units is also important to the elimination of significant contribution in keeping with the EPA's Step 3 determinations, the EPA is supplementing the previously discussed enhancements with two other new sets of provisions that will apply to certain individual units within the larger context of the Group 3 trading program. The allowance price will continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements will be important supplemental drivers of performance and will offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by more continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO_X emissions rate provisions that will apply to large coal-fired EGUs, defined for this purpose as units serving electricity generators with nameplate capacities equal to or greater than 100 MW and combusting any coal during the control period in question. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement will be integrated into the trading program as a new component in the calculation of each unit's primary emissions limitation, such that the additional allowances will have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered will be determined by computing, for each day of the control period, any excess of the unit's reported emissions (in pounds) over the emissions that would have resulted from combusting that day's actual heat input at an average daily emissions rate of 0.14 lb/mmBtu, summing the daily amounts, converting from pounds to tons, computing the amount of any excess over 50 tons, and multiplying by two. Starting with the second control period in which newly installed SCR controls are operational, but not later than the 2030 control period, the 3-for-1 surrender ratio will apply in the same way to all large coal-fired EGUs except circulating fluidized bed units, consistent with EPA's determination that a control stringency reflecting installation and operation of SCR controls on all such large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

In prior rules addressing interstate transport of air pollution, stakeholders have noted that while seasonal cap-and-trade programs are effective at lowering ozone and ozone-forming precursors across the ozone season, attainment of the standard is measured on key days and therefore it is necessary to ensure that the rule requires emissions reductions not just seasonally, but also on those key days.[296] They have noted that while the trading programs established under the NO_X SIP Call, CAIR, and CSAPR have all been successful in ensuring seasonal reductions, states must remain below daily peak levels, not just seasonal levels, to reach attainment. These downwind stakeholder communities have suggested that operating pollution controls on the highest ozone days (and immediately preceding days) during the ozone season is of critical importance. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and has identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. These instances are discussed in section V.B.1.a of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-optimization to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of subsequent-year data for prior programs suggests that the non-optimization

[296] *E.g.,* comments of Maryland Department of the Environment on the proposed Revised CSAPR Update at 3, EPA–HQ–OAR–2020–0272–0094.

behavior increases in the latter years of a program. Applied to this context (*e.g.,* a rule providing a full remedy to interstate transport for the more protective 2015 ozone NAAQS and an extended period of expected persistence of receptors), this data suggests this deterioration in performance could become prevalent and problematic in future years if not addressed. Rather than allow for the potential of continued deterioration in the environmental performance of our trading programs, the EPA finds the evidence of declining SCR performance in later years of trading programs sufficient to justify prophylactic measures in this rule to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more protective 2015 ozone NAAQS combined with the full remedy nature of this action and the extended timeframe for which upwind contribution to downwind nonattainment is projected to persist, the EPA agrees with these stakeholders that the set of measures promulgated in this rulemaking to implement the control stringency levels found necessary to address states' good neighbor obligations should include measures designed to more effectively ensure that individual units operate their emissions controls routinely throughout the ozone season, thereby also ensuring that the controls are planned to be in operation on the particular days that turn out to be most critical for ozone formation and for attainment of the NAAQS. Routine operation of emissions controls will also provide relief to overburdened communities downwind of any units that might otherwise have chosen not to operate their controls. In the Ozone Transport Policy Analysis Final Rule TSD, the EPA conducted a screening analysis that found nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. Thus, the EPA is adopting backstop daily rate limits at the individual unit level because it is appropriate and justified in the context of eliminating significant contribution under CAA section 110(a)(2)(D)(i)(I). While the former justification is sufficient to finalize this enhancement to the trading program, we also anticipate that this measure will deliver public health and environmental benefits to overburdened communities (as well as the rest of the population).[297]

We considered whether, as some commenters suggested, it would be appropriate to simply implement unit-specific daily emissions limitation at all of the large, coal-fired EGUs, and forego an emissions trading approach altogether. While this is within the EPA's statutory authority, *see* CAA section 110(a)(2)(A) and 302(y), and merits careful consideration, we are declining to do so in this action but intend to closely monitor EGU emissions performance in response to the trading program finalized here. The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional allowance surrender requirements instead of as an enforceable emissions limitation is to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. As discussed in section VI.B.7 of this document, under the EPA's historical trading programs without the enhancements made in this rulemaking, some individual coal-fired units with SCR controls have chosen to operate the controls at lower removal efficiencies than in past ozone seasons or even to idle the controls for entire ozone seasons. In addition, some SCR-equipped units have chosen to routinely cycle their emissions controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the controls to be operated under those conditions, or not operating the units under those conditions. Collectively, this non-optimization of existing controls has a detrimental impact on problematic receptors. Table V.D.1–1 shows the expected air quality benefit from control optimization (totaling nearly 1.6 ppb change across all receptors).[298]

The EPA has identified sources of interstate ozone pollution such as the New Madrid and Conemaugh plants (in Missouri and Pennsylvania, respectively) whose SCR controls were not operating for substantial portions of recent ozone seasons. The data included in Appendix G of the Ozone Transport Policy Analysis Final Rule TSD, available in the docket for this rulemaking, demonstrate that these units have operated their SCRs better and more consistently during years with higher NO_X allowance prices. Downwind stakeholders have noted that some of the higher emissions rates (specifically in the case of Conemaugh Unit 2 in 2019) have occurred on the day of and the preceding day of an ozone exceedance in bordering states.[299]

The EPA believes that the design of the daily emissions rate provisions will be effective in addressing these types of high-emitting behavior by significantly raising the cost of planned operator decisions that substantially compromise environmental performance. At the same time, the provision will not unduly penalize an occasional unplanned exceedance, because the amount of additional allowances that would have to be surrendered to address a single day's exceedance would be much smaller than the amount that would have to be surrendered to address planned poor performance sustained over longer time periods. Moreover, the EPA believes that the inclusion of a 50-ton threshold before the increased surrender requirements would apply is sufficient to address virtually all instances where a unit's emissions would exceed the 0.14 lb/mmBtu daily rate because of unavoidable startup or shutdown conditions during which SCR equipment cannot be operated, thereby ensuring that the provision will not penalize units for emissions that are beyond their reasonable control.

The EPA is applying the daily emissions rate provisions to large coal-fired EGUs, and not to other types of units, for reasons that are consistent with EPA's determinations regarding the appropriate control stringency for EGUs to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. Installation and operation of SCR controls is well-established as a common practice for the best control of NO_X emissions from coal-fired EGUs, as evidenced by the fact that the technology is already installed on more than 60 percent of the sector's total coal-fired capacity and installed on nearly 100 percent of the coal fired boilers in the top quartile of emissions rate performance. In the context of addressing good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is determining that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs (other than circulating fluidized bed units) is appropriate at Step 3. Finally, where SCR controls are installed on such units, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions

[297] Nonetheless, the environmental justice exposure analysis indicates that preexisting disparities among demographic groups are likely to persist even under this final rule. *See* section VII of this document.

[298] As illustrated in the table and underlying data, a small portion of this ppb impact is attributable to combustion control upgrade potential.

[299] EPA–HQ–OAR–2020–0272–0094.

reductions. The EPA believes these considerations support establishment of the daily emissions rate provisions on a universal basis for large coal-fired EGUs, with near-term application of the provisions for units that already have the controls installed and deferred application for other units, as discussed later.

With regard to gas-fired steam EGUs, SCR controls are nowhere near as prevalent, and while the EPA is including some SCR controls at gas-fired steam units in the selected control stringency at Step 3, the EPA is not including universal SCR controls at gas-fired steam units. Because the EPA is not determining that universal installation and operation of SCR controls at gas-fired steam EGUs is part of the selected control stringency, in order not to constrain the power sector's flexibility to choose which particular gas-fired steam EGUs are the preferred candidates for achieving the required emissions reductions, the EPA is not applying the daily emissions rate provisions to large gas-fired steam EGUs. Focusing the backstop daily emissions rates on coal-fired units is also consistent with stakeholder input which has emphasized the need for short-term rate limits at coal units given their relatively higher emissions rates.

The EPA developed the level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in section VI.B.7 of this document. A rate of 0.14 lb/mmBtu represents the daily average NO_X emissions rate that has been demonstrated to be achievable on approximately 95 percent of days covering more than 99 percent of total ozone-season NO_X emissions by coal-fired units with SCR controls that are achieving a seasonal NO_X average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO_X emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

As noted previously, the daily average emissions rate provisions will apply beginning in the 2024 control period for large coal-fired units with installed SCR controls, one control period later than optimization of those controls will be reflected in the state emissions budgets under this rule. For these units, not applying the daily average rate provisions until 2024 serves three purposes. First, it provides all the units with a preparatory interval to focus attention on improving not only the average performance of their SCR controls but also the day-to-day consistency of performance before they will be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it provides the subset of units that exhaust to common stacks with other units that currently lack SCR controls an opportunity to exercise the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately; otherwise, the daily emissions rate provisions will apply to the SCR-equipped units based on the combined NO_X emissions rates measured in the common stacks. Third, it provides all units sufficient time to update the data handling software in their existing monitoring systems as needed to compute and report the additional hourly and daily data values needed for implementation of the provisions.[300]

With respect to the units without existing SCR controls, the daily average emissions rate provisions will apply starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. This implementation timing represents a change from the proposal, under which the daily average emissions rate provisions would have applied to units without existing SCR starting in the 2027 control period. Commenters noted that for many units without SCR, replacement of the unit within a few years, and shifting of some generation to cleaner units in the interim, would be a more economic compliance strategy than installation of new SCR controls. The commenters further noted that implementation of the daily average emissions rate for these units starting in 2027 would strongly disadvantage such an alternative strategy if the capacity replacement and any associated transmission improvements could not be implemented by 2027. In light of these comments, the EPA has determined that as long as the emissions budgets determined in this rule to eliminate significant contribution are still being implemented as expeditiously as practicable—which in this instance the EPA has determined requires phasing in the required emissions reductions by 2027—it is reasonable to defer implementation of the daily average emissions rate provisions to 2030 for units without SCR to allow temporarily greater flexibility to pursue compliance strategies other than installation of new controls. This lag is permissible consistent with the obligation to eliminate significant contribution for reasons that are further discussed in response to comments in section VI.B.1.d of this document. However, for any units that choose a compliance strategy of installing new SCR controls before 2030, the daily average emissions rate provisions would apply in the second control period of operation. Specification of the second control period rather than the first control period provides the unit operators with an opportunity to gain operational experience with the new equipment before the units will be held to increased allowance-surrender consequences for exceeding the daily rate.

The unit-specific daily emissions rate provisions are being finalized as proposed except for two changes noted in the previous summary: the exclusion from extra allowance surrender requirements of a unit's first 50 tons of emissions in a control period exceeding the backstop daily rate, and the revision of the starting date for implementation of the requirement for units without existing SCR controls to 2030 or the second control period of SCR operation, if earlier. The rationale for these changes is further discussed in the responses to comments later in this section. Additional details of the unit-specific daily emissions rate provisions are discussed in section VI.B.7 of this document.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations for units with post-combustion controls starting with the 2024 control period. The secondary emissions limitations will be determined on a unit-specific basis according to each unit's individual performance but will apply to a given unit only under the circumstance where a state's assurance level for a control period has been exceeded, the unit is included in a group of units to which responsibility for the exceedance has been apportioned under the program's assurance provisions, and the unit operated during at least 10 percent of the hours in the control period. Where these conditions for application of a secondary emissions limitation to a given unit for a given control period are met, the unit's secondary emissions limitation consists of a prohibition on NO_X emissions during the control

[300] For further discussion of emissions monitoring and reporting requirements under the rule, including the options available to plants where SCR-equipped and non-SCR-equipped coal-fired units exhaust to common stacks, see section VI.B.10 of this document.

period that exceed by more than 50 tons the NO_X emissions that would have resulted if the unit had achieved an average emissions rate for the control period equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest average emissions rate for any previous control period under any CSAPR seasonal NO_X trading program during which the unit operated for at least 10 percent of the hours.

The secondary emissions limitation is in addition to, not in lieu of, the primary emissions limitation applicable to each source, which continues to take the form of a requirement to surrender a quantity of allowances based on the source's emissions, and also in addition to the existing assurance provisions, which similarly continue to take the form of a requirement for the owners and operators of some sources to surrender additional allowances when a state's assurance level is exceeded. In contrast to these other requirements, the unit-specific secondary emissions limitation takes the form of a prohibition on emissions over a specified level, such that any emissions by a unit exceeding its secondary emissions limitation would be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities. The reason for establishing this form of limitation is that experience under the existing CSAPR trading programs has shown that, in some circumstances, the existing assurance provisions have been insufficient to prevent exceedances of a state's assurance level for a control period even when the likelihood of an exceedance has been foreseeable and the exceedance could have been readily avoided if certain units had operated with emissions rates closer to the lower emissions rates achieved in past control periods. The assurance levels exist to ensure that emissions from each state that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state are prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the evidence of foreseeable and avoidable exceedances of the assurance levels demonstrates that EPA's existing approach has not been sufficient to accomplish this.

The purpose of including assurance levels higher than the state emissions budgets in the CSAPR trading programs is to provide flexibility to accommodate operational variability attributable to factors that are largely outside of an individual owner's or operator's control, not to allow owners and operators to plan to emit at emissions rates that could be anticipated to cause a state's total emissions to exceed the state's emissions budget or assurance level. Conduct leading to a foreseeable, readily avoidable exceedance of a state's assurance level cannot be reconciled with the statutory mandate of the CAA's good neighbor provision that emissions "within the state" significantly contributing to nonattainment or interfering with maintenance of a NAAQS in another state must be prohibited. Because the current CSAPR regulations do not expressly prohibit such conduct and have proven insufficient to deter it in some circumstances, the EPA is correcting the regulatory deficiency in the Group 3 trading program by adding secondary emissions limitations that cannot be complied with through the use of allowances.

The EPA notes that although the purpose of the secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations will strengthen the incentives for individual units with post-combustion controls to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. The new limitations will strengthen the incentives to operate and optimize the controls continuously, which can be expected to reduce some individual units' emissions rates throughout the ozone season, including on the days that turn out to be most critical for downwind ozone levels. Better emissions performance on average across the ozone season by individual units likely will also help address impacts of pollution on overburdened communities downwind from some such units. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E.

The unit-specific secondary emissions limitations are being finalized as proposed except that the limitations will apply only to units with post-combustion controls. The rationale for this change, and additional details regarding the provisions, are discussed in section VI.B.8 of this document.

d. Responses to General Comments on the Revisions to the Group 3 Trading Program

This section summarizes and provides the EPA's responses to overarching comments received on the EPA's proposal to implement the emissions reductions required from EGUs under this rule through expansion and enhancement of the Group 3 trading program originally established in the Revised CSAPR Update, particularly comments on electric system reliability. Responses to comments about individual aspects of the enhanced trading program are addressed in the respective subsections of this section in which those aspects are discussed. Responses to comments concerning alleged overcontrol and the EPA's legal authority are in sections V.D. and III. Comments not addressed in this document are addressed in the separate *RTC* document available in the docket for this action.

Comment: Some commenters, including EGU owners, states, and several RTOs, expressed concern that the requirements for EGUs as formulated in the proposal could lead to a degradation in the reliability of the electric system. As background, some of these commenters noted that the power sector is currently undergoing rapid change, with older and less economic fossil-fuel-fired steam generating units retiring while the majority of the new capacity being added consists of wind and solar capacity. They noted that fossil-fuel-fired generating capacity provides reliability benefits not necessarily provided by other types of generating capacity, including not only the ability to generate electricity in the absence of wind or sunlight, but also inertia, ramping capability, voltage support, and frequency response. Commenters stated that past EGU retirements and the pace of change in the generating capacity mix have already been stressing the electric system in some regions, and that the forecasted risk of events where the electric system would be unable to fully meet load is rising.

For purposes of their comments, these commenters generally assumed that the rule would lead to additional retirements of fossil-fuel-fired generating capacity beyond the retirements that EGU owners have already planned and announced. Some of the commenters also suggested that remaining fossil-fuel-fired generators would be unwilling to operate when needed because allowances might be unavailable for purchase or too costly. In the context of an already-stressed electric system, the commenters predicted that these assumed consequences of the rule would threaten resource adequacy and result in degraded electric reliability. To support their assumptions concerning additional retirements, some of the commenters pointed to projections of incremental generating capacity retirements included in the results of modeling performed by the EPA to analyze the costs and benefits of the proposed rule. Some commenters indicated that they expected EGU owners to be interested in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and expressed concern that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy; for these commenters, 2027 and the immediately following years were the period of greatest concern. Some commenters appear simply to have assumed that owners of units not already equipped with SCR controls would choose to retire the units as of the ozone season in which the units would otherwise become subject to the backstop daily emissions rate provisions, regardless of whether replacement investments had been completed.

Some of the commenters raising concerns about electric system reliability suggested potential modifications to the proposed rule that the commenters believed could help address their concerns. The suggestions included various mechanisms for suspending some or all of the trading program's requirements for certain EGUs at times when an RTO or other entity responsible for overseeing a region of the interconnected electrical grid determines that generation from those EGUs is needed and the EGUs might not otherwise agree to operate. Other suggestions focused on ways of providing EGUs with greater confidence that allowances would be available to cover their incremental emissions during particular events. A number of commenters used the term "reliability safety valve," in some cases with reference to the types of suggestions just mentioned and in other cases without details. Some commenters pointed to the "safety valve" provision included in the Group 2 trading program regulations under the Revised CSAPR Update. Another commenter pointed to provisions for a "reliability safety valve" included in the Clean Power Plan (80 FR 64662, Oct. 23, 2015).

In addition to offering critiques and recommendations concerning the proposed rule's contents, some commenters claimed that the EPA had failed to conduct sufficient analysis of the potential implications of the proposed rule on electrical system reliability. These commenters called on the EPA to consult with RTOs and other entities with responsibilities relating to electric system reliability and to perform additional analysis. Some commenters advocated for renewed consultations and analysis before each planned adjustment to emissions budgets under the dynamic budget-setting process. Commenters cited the consultation processes followed during implementation of other EPA rules, such as the Mercury and Air Toxics Standards (MATS) (77 FR 9304, Feb. 16, 2012).

Response: The EPA disagrees with the comments asserting that this rule would threaten resource adequacy or otherwise degrade electric system reliability. The emissions reduction requirements for EGUs under this rule are being implemented through the mechanism of an allowance trading program. Under the trading program, no EGU is required to cease operation. The core trading program requirements for a participating EGU are to monitor and report the unit's NO_X emissions for each ozone season period and to surrender a quantity of allowances after the end of the ozone season based on the reported emissions. To address states' obligations under the good neighbor provision, some units of course will have to take some type of action to reduce emissions, the actions taken to reduce emissions will generally have costs, and some EGU owners will conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some comments nevertheless assume that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service. Assumptions of this nature are simply not reasonable. Like many commenters, the EPA does expect that retirement will be viewed as a more economic compliance strategy for some EGUs than installing new controls, but the Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected. The trading program inherently provides ample flexibility to allow such an orderly transition to take place. In addition, as discussed later in this section, the EPA has adopted several changes in the final rule to increase flexibility specifically for the early years of the trading program for which commenters have indicated the greatest concerns about electric system reliability.

As an initial matter, the EPA notes two fundamental aspects of this rulemaking which together provide a strong foundation for the Agency's conclusion that the emissions reductions required from EGUs can be achieved with no adverse impacts on electric system reliability. First, there is ample evidence indicating that the required emissions reductions are feasible. As discussed in section V of this document, the magnitude and timing of the EGU emissions reductions required by this action reflect application of technologies that are already in widespread use, on schedules that are supported by industry experience. Second, the required emissions reductions are being implemented through the mechanism of a trading program. The enhanced trading program under this rule, like the trading programs established by the EPA under prior rules, provides EGU owners with opportunities to substitute emissions reductions from sources where achieving reductions is cheaper and easier for emissions reductions from other sources where achieving reductions is more costly or difficult. In general, an EGU owner has options to operate the emissions controls identified by the EPA for that type of unit (including installation or upgrade of controls where necessary), operate other types of emissions controls, or adapt the unit's levels of operation to produce less generation if the unit is a higher-emitting EGU or more generation if the unit is a lower-emitting EGU. The backstop daily emissions rate provisions in this rule reduce the degree of available flexibility relative to the degree of flexibility in the Agency's previous trading programs under CAIR and CSAPR but by no means eliminate it. Moreover, even the backstop rate provisions are structured as requirements to surrender additional allowances rather than as hard limits, providing a further element of flexibility No EGU is required to retire or is prohibited from operating at any time under this rule. EGUs only need to surrender of the appropriate quantities of allowances after the end of the control period.[301]

Further, in the large number of comments submitted in this rulemaking that assert concerns over electric system reliability, no commenter has cited a single instance where implementation of an EPA trading program has actually caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior trading program rulemakings have shown a considerable gap between rhetoric and reality. For example, in the litigation over the industry's multiple motions to stay implementation of CSAPR, claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets despite CSAPR not being in effect.[302] Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emissions reduction targets without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) ("[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own. . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' ") (quoting 84 FR 32561). The claims that these rules would have had adverse reliability impacts were proved to be groundless.

Notwithstanding the long experience confirming the ability of the EPA's trading programs to obtain emissions reductions from EGUs without impairing the sector's ability to provide reliable electric service, the Agency of course does not rely here solely on its experience, but has carefully reviewed the comments on this topic for any information that might indicate the appropriateness of modifications to the enhanced trading program as proposed. In recognition of the important role that RTOs play in ensuring electric system reliability, and consistent with the requests of some commenters, the EPA has engaged in outreach to the RTOs that commented on the proposal to better understand their comments specifically and the reliability-related comments of other commenters more generally.[303] Through these meetings, the central reliability-related concern was identified as one of timing. In order for retirement to be a viable compliance strategy for a unit that cannot be entirely spared until replacement investments in generation or transmission are completed, it must be possible for the unit to operate at critical times for a transition period. Like other stakeholders, the RTOs perceived implementation of the backstop daily emissions rate provisions on uncontrolled units as materially strengthening incentives for such units to either install controls or retire. The RTOs were concerned that the option for a coal-fired unit without SCR controls to maintain limited operation while surrendering allowances at a 3-for-1 ratio for all emissions exceeding the backstop daily rate was one that EGU owners would be reluctant to pursue. Accordingly, the RTOs expected considerable interest from EGU owners in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and they were concerned that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy. The RTOs described their concerns as greatest through approximately the 2029 control period.

The RTOs also described a concern about potentially illiquid allowance markets. They believed it was possible that some EGUs might claim an inability to operate at particular times when needed unless they had confidence that they would be able obtain additional allowances. The RTOs were particularly concerned that introduction of dynamic budgeting as proposed would create uncertainty for some EGUs regarding the quantities of allowances they would have available for use, particularly given the potentially large year-to-year swings if budgets were based on historical data from a single year. Some of the RTOs suggested potential solutions for these issues, principally in the form of auctions or RTO-administered allocations of allowances from pools of supplemental allowances, with access to the supplemental allowances triggered by certain indications of temporary stress on the electric system.

In the final rule, the EPA is adopting several changes from the proposal to help address the reliability-related concerns that were identified in comments and brought into greater focus by the consultations with the RTOs. The first change adopted in response to these comments is that application of the backstop daily NO_X emissions rate to units without existing SCR controls is being deferred until the 2030 control period, or the second control period in which a unit operates new SCR controls, if earlier. The purpose of this change is to address the concerns that application of the backstop daily NO_X emissions rate to EGUs without existing SCR starting in 2027 would provide insufficient time for planning and investments needed to facilitate unit retirement as a compliance pathway, which some commenters noted they prefer or have already planned. In particular, where an EGU owner would prefer to retire and replace an uncontrolled EGU rather than to install new controls, and in recognition that reliability-related needs may require some degree of operation from such units in the period before the investments needed to replace the unit can be completed, deferral of the backstop daily emissions rate provisions ensures that the necessary generation can be provided without being made subject to a 3-for-1 allowance surrender ratio that might render that compliance strategy uneconomic compared to the faster but less environmentally beneficial compliance strategy of installing new controls. The EPA has considered the statutory mandate that states' good neighbor obligations—

[301] The EPA has prepared a resource adequacy assessment of the projected impacts of the final rule showing that the projected impacts of the final rule on power system operations, under conditions preserving resource adequacy, are modest and manageable. See *Resource Adequacy and Reliability Analysis Final Rule TSD,* available in the docket.

[302] For a state-by-state comparison, see Appendix G of the Ozone Transport Policy Analysis Final Rule TSD.

[303] The EPA also met with non-RTO balancing authorities that submitted comments. Memoranda identifying the dates, attendees, and topics of discussion of these meetings with RTOs and non-RTO balancing authorities are available in the docket.

including this action's requirement for large coal-fired EGUs to make emissions reductions commensurate with good SCR operation—be addressed as expeditiously as practicable. The EPA has also considered the fact that in this rule, the backstop daily emissions rate serves as a supplement to the broader requirement for emissions reductions commensurate with application of several control technologies at several types of EGUs, encompassing the extent of emissions reductions that would be incentivized by the backstop emissions rate requirement. The EPA views the backstop daily emissions rate as part of the solution to eliminating significant contribution in that it strongly incentivizes emissions-control operation throughout each day of the ozone season. *See* sections III.B.1.d, VI.B.1.b, VI.B.1.c.i. For that reason, in general we are finalizing the daily backstop emissions rate for units that have SCR installed or that install it in the future. It is only as an exception to that general rule that we defer the backstop daily emissions rate given the transition period and reliability concerns identified by commenters. The EPA finds that in this circumstance, as long as state emissions budgets continue to reflect the required degree of emissions reductions, deferral of the backstop rate requirement for uncontrolled units for a transition period can be justified on the basis of the greater long-term environmental benefits obtained through facilitating the replacement of these affected EGUs with cleaner sources of generation. Beginning in the 2030 ozone season, all coal-fired EGUs identified for SCR retrofit potential in this action will be subject to the backstop daily emissions rate. Any such units that remain in operation in that year can and should meet the backstop daily emissions rate or be subject to the heightened allowance surrender ratio.

The second change from the proposal adopted in response to the reliability-related comments is that the target percentage of the states' emissions budgets used to recalibrate the target bank level will be set at the proposed 10.5 percent starting in the 2030 control period, and for the control periods from 2024 through 2029, a target percentage of 21 percent will be used instead. The adoption of the higher target percentage for use through the 2029 control period is intended to promote greater allowance market liquidity during a period of relatively rapid fleet transition about which commenters expressed more focused reliability-related needs. As discussed later in this section, the EPA expects the introduction of the bank recalibration process in 2024 generally to boost market liquidity (by discouraging allowance hoarding) and also considers the target percentage of 10.5 percent set forth in the proposal well supported. Nevertheless, the Agency agrees with suggestions by commenters that, at least in the early years of the enhanced trading program, a larger bank would provide further liquidity and would give program participants greater confidence that allowances would be available for purchase when needed. Greater confidence by sources would help address RTOs' concern about the possibility that some sources could be reluctant to operate if they were unsure of their ability to procure allowances to cover their emissions. In finding that this modification from proposal is appropriate, the EPA has considered the fact that use of a higher target percentage will not result in the creation of any additional allowances in any control period, because under the recalibration provisions, when the total quantity of allowances banked from the previous control period is less than the bank target level, the consequence is not that additional allowances are created to raise the bank to the target level, but simply that no bank adjustment is carried out. We also note that while including an annual bank recalibration of any percentage is an enhancement in the trading program from prior trading programs under the good neighbor provision established in the CAIR, CSAPR, CSAPR Update, and Revised CSAPR Update rulemakings, it is not unprecedented; the trading program established under the NO_X SIP Call included ''progressive flow control'' provisions that were designed differently from the bank recalibration provisions in this rule but had the same purpose and general effect.

The third change from the proposal adopted in response to the reliability-related comments is that the EPA is determining preset state emissions budgets not only for the control periods in 2023 and 2024 as proposed, but also for the control periods in 2025 through 2029. Finalizing preset state emissions budgets through 2029 will establish predictable amounts for the minimum quantities of allowances available during the period when commenters have expressed concern that the reliability-related need for such predictability is greatest. Moreover, the EPA will also determine state emissions budgets using the final dynamic budget-setting methodology for the control periods in 2026 through 2029, and for each state and control period, the dynamic budget to be published in the future will only supplant the preset budget finalized in this rule for a control period in which that dynamic budget is higher than the corresponding preset budget. The reason for using dynamic budgets when they are higher than the corresponding preset budgets is that the EPA recognizes that evolution of the EGU fleet will not follow the exact path projected at the time of the rulemaking, and that by not accounting for certain events, the preset methodology could result in issuance of smaller quantities of allowances than the EPA would find consistent with the quantities of emissions from a well-controlled EGU fleet using the dynamic budget-setting methodology. Events that could cause preset budgets to underpredict a state's well-controlled emissions, which are more likely in years farther in the future from the time of the rulemaking, include deferral of a large EGU's previously planned retirement date or increases in electricity demand that outpace the general trend of lower-emitting or non-emitting generation replacing higher-emitting generation. After considering the commenters' interest in greater predictability during the early years of the amended trading program as well as the need to protect against instances where the preset budgets could underpredict a state's well-controlled emissions in years farther from the year of the rulemaking, the EPA finds that the combination of these factors justifies the approach of using the higher of the two budgets for the control periods from 2026 through 2029.

In addition to the changes made in response to reliability-related comments, several other changes to the proposal being adopted primarily for other reasons will also help address the factors identified as reliability-related concerns. Most notably, the EPA is adopting changes to the dynamic budget computation procedure to incorporate multiple years of heat input data, which will reduce year-to-year variability in the budgets determined under that procedure and should to some extent reduce uncertainty about the quantities of allowances available for use in instances where a dynamic budget is being used instead of preset budget. In addition, the adoption of a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate should ensure that no unit incurs the higher surrender ratio solely because of unavoidable emissions during startup and should help address concerns that some units might be reluctant to operate because of the associated emissions-related costs. Also, the 2026–2027 phase-in of emissions reductions commensurate with installation of new SCR controls will increase the quantities of allowances available in the 2026 state emissions budgets for most states in the trading program.

To summarize: in light of the strong record supporting the feasibility of the emissions reductions required from EGUs; the use of a trading program as the mechanism for achieving those emissions reductions, with multiple options for achieving compliance and no requirements to cease operation of any individual EGU at any time; the established processes of RTOs, other balancing authorities, and state regulators for managing any EGU retirement requests that do occur in an orderly manner with evaluation of potential reliability impacts and implementation of mitigation measures where needed; the unbroken, decades-long historical success of the EPA's trading programs at achieving emissions reductions without any adverse reliability impacts; the views expressed by commenters that facilitating EGU retirement and replacement as a possible compliance strategy through 2029 would be particularly helpful; the changes made in the final rule for control periods through 2029 specifically to increase flexibility during this transitional period, including deferring application of the backstop daily emissions rate provisions for EGUs without existing SCR controls, increasing the target percentage used to determine the target allowance bank level for purposes of the bank recalibration provisions, and establishing preset state emissions budgets which serve as floors against potential dynamic budget imposition in those control periods; and the changes made in the final rule incorporating multiple years of heat input data into the dynamic budget-setting procedure, adding a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate, and phasing in emissions reductions requirements commensurate with new SCR installations through 2027; the EPA concludes that this action does not pose any material risk of adverse impact to electric system reliability.

The EPA has also considered the other suggestions offered by commenters for addressing reliability-related issues. With respect to suggestions that the rule should include provisions allowing some or all of the trading program's requirements to be suspended at times when an RTO or other entity with grid management responsibilities determines there is a reliability-related need, the EPA again observes that the rule's emissions reduction requirements are being implemented through a trading program mechanism which makes exceptions of this nature unnecessary. Trading programs inherently offer the flexibility to accommodate variability in the utilization of individual units. The "reliability safety valve" provisions in the Clean Power Plan, which one commenter cited as a precedent to support some form of temporary exemption under this rule, in fact was available only in situations where a state plan did not allow emissions trading and instead imposed unit-specific emissions constraints. *See* 80 FR 64877–879. Even the 3-for-1 allowance surrender ratio under the backstop daily NO_X emissions rate provisions can be met through the surrender of additional allowances. The rule does not bar any EGU from operating at any time as long as all allowance surrender requirements are met.

With respect to suggestions that the EPA must undertake recurring modeling of the evolving electrical system and consult with RTOs before each planned adjustment to emissions budgets, which start from the premise that the rule poses risk to electric system reliability that must be continuously monitored, the EPA disagrees with the premise and therefore also disagrees with the suggestions. As discussed in section V of this document, the EPA has taken care to ensure that the emissions reduction requirements applicable to EGUs under this rule are feasible through application of the control technologies selected as the basis of the emissions reductions. The EPA has also performed modeling in this rulemaking to assess the benefits and costs of the rule when all required emissions reductions are achieved. That modeling, which incorporates a representation of electrical grid regions and interregional constraints on energy and capacity exchange, affirms the feasibility of the overall emissions reduction requirements and is illustrative of a control strategy where some units retire and are replaced instead of installing new controls. The EPA has also consulted with the RTOs (as well as other balancing authorities) in the course of this rulemaking to ensure that the EPA understood the concerns expressed in their comments such that we could address those comments in this final rule. The EPA does not agree that further modeling or ongoing consultations with RTOs are needed in advance of the recurring dynamic budget adjustments, which do not increase the stringency of the rule's emissions reduction requirements established in the final rule. The extensive consultation processes adopted by the Agency in conjunction with the MATS rulemaking are not a relevant precedent; the MATS rule, which was promulgated to address a different statutory mandate, was structured in the form of unit-specific emissions constraints, fundamentally different from the requirements of this rule. The EPA notes that other entities responsible for maintaining reliability and managing entry and exit of resources, including the North American Electric Reliability Corporation (NERC) and RTOs and other balancing authorities, already routinely assess resource adequacy and reliability inclusive of meeting all regulatory requirements, including environmental requirements.

While the EPA does not agree that such consultations are a necessary precondition for successful implementation of this rule, the Agency remains available to engage with any affected EGU or reliability authority requesting to meet and discuss the intersection of its power sector regulatory programs with electric reliability planning and operations. The EPA is also continuing its practice of meeting with the U.S. Department of Energy and the Federal Energy Regulatory Commission to maintain mutual awareness of how Federal actions and programs intersect with the industry's responsibility to maintain electric reliability.[304]

The EPA is not adopting the suggestion to replicate the so-called "safety valve" mechanism created under the Revised CSAPR Update. That mechanism, cited by some commenters as potential precedent for an unspecified form of "reliability safety valve" in this action, gave owners of covered EGUs a one-time opportunity to voluntarily convert allowances banked under the Group 2 trading program to allowances useable in the Group 3 trading program at an 18-for-1 ratio for use in the trading program's initial control period in 2021. *See* 82 FR 23137–138. EGU owners chose to use the voluntary mechanism to acquire a total of 382 allowances, representing only 0.36 percent of the sum of the state emissions budgets and only 0.26 percent

[304] *See, e.g.,* U.S. Department of Energy and U.S. Environmental Protection Agency, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (March 8, 2023), available at *https://www.epa.gov/power-sector/electric-reliability-mou.*

of the total quantity of allowances available for compliance in that control period.[305] For the 2023 control period, the bank of allowances carried over from the 2022 control period plus the incremental starting bank that will be created by conversion of additional allowances banked under the Group 2 trading program (see section VI.B.12.b of this document) will total over 30 percent of the full-season emissions budgets.[306] Given the larger starting bank and this rule's bank recalibration provisions (which will be implemented starting with the 2024 control period, but which the EPA expects will increase allowance market liquidity starting with the 2023 control period), the Agency views establishment of a one-time voluntary conversion opportunity for the 2023 control period analogous to the Revised CSAPR Update's "safety valve" provision as unnecessary.

Finally, in the final rule the EPA is not adopting any of the other suggestions concerning additional mechanisms to make additional allowances available through auctions or RTO-administered allowance pools. For the reasons discussed throughout this section, the EPA concludes that the trading program as established in this action provides a flexible compliance mechanism that will allow the required emissions reductions to be achieved without the need for creation of additional allowances. However, the EPA also recognizes the potential for allowance market liquidity to be further increased through some form of auction mechanism. For instance, it may be appropriate to pair the introduction of an auction with a reduction in the bank recalibration percentage that begins earlier than 2030. Through a supplemental rulemaking, the Agency intends to propose and take comment on potential amendments to the Group 3 trading program that would add such an auction mechanism to the regulations and make other appropriate adjustments in the implementation framework at Step 4.[307]

2. Expansion of Geographic Scope

In light of the findings at Steps 1, 2, and 3 of the 4-step interstate transport framework, the EPA is expanding the geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass additional states (and Indian country within the borders of such states) with EGU emissions that significantly contribute for purposes of the 2015 ozone NAAQS. Specifically, the EPA is expanding the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and Wisconsin. Any unit located in a newly added jurisdiction that meets the applicability criteria for the Group 3 trading program will become an affected unit under the program, as discussed in section VI.B.3 of this document.

CSAPR, the CSAPR Update, and the Revised CSAPR Update also applied to sources in Indian country, although, when those rules were issued, no existing EGUs within the regions covered by the rules were located on lands that the EPA understood at the time to be Indian country.[308] In contrast, within the geographic scope of this rulemaking, the EPA is aware of areas of Indian country within the borders of both Utah and Oklahoma with existing EGUs that meet the program's applicability criteria. Issues related to state, tribal, and Federal CAA implementation planning authority with respect to sources in Indian country in general and in these areas in particular are discussed in section III.C.2 of this document. EPA's approach for determining a portion of each state's budget for each control period that will be set aside for allocation to any units in areas of Indian country within the state not subject to the state's CAA implementation planning authority is discussed in section VI.B.9 of this document.

Units within the borders of each newly added state will join the Group 3 trading program on one of two possible dates during the program's 2023 control period (that is, the period from May 1, 2023, through September 30, 2023). The reason that two entry dates are necessary is that, as discussed in section VI.B.12.a of this document, the effective date is expected to fall after May 1, 2023. In the case of states (and Indian country within the states' borders) whose sources do not currently participate in the CSAPR NO_X Ozone Season Group 2 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the rule's effective date. However, in the case of the states (and Indian country within the states' borders) whose sources do currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin participating in the Group 3 trading program on May 1, 2023, regardless of the rule's effective date, subject to transitional provisions designed to ensure that the increased stringency of the Group 3 trading program as revised in this rulemaking will not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources historically covered by the Group 2 trading program than the alternative approach of being required to switch from the Group 2 trading program to the Group 3 trading program in the middle of a control period, and it is the same approach that was followed for sources that transitioned from the Group 2 trading program to the Group 3 trading program in 2021 under the Revised CSAPR Update. Section VI.B.12.a of this document contains further discussion of the rationale for this approach and the specific transitional provisions.

The EPA notes that under the rule, the expanded Group 3 trading program will include not only 19 states for which the EPA is determining that the required control stringency includes, among other measures, installation of new post-combustion controls, but also three

[305] Additional allowances available for compliance under the Group 3 trading program in the 2021 control period included a starting allowance bank created through mandatory conversion of a portion of the allowances banked under the Group 2 trading program as well as supplemental allowances issued to ensure that no provisions of the Revised CSAPR Update increasing regulatory stringency would take effect before that rule's effective date. *See* 86 FR 23133–137.

[306] The full-season emissions budgets for the 2023 control period under the Group 3 trading program and the incremental starting bank created in this action through conversion of additional Group 2 allowances (but not the bank of allowances carried over from the 2022 control period under the Group 3 trading program) will be prorated to reflect the portion of the 2023 ozone season occurring after the effective date of this rule. See sections VI.B.12.a. and VI.B.12.b.

[307] Such a rulemaking would not reopen any determinations which the Agency has made at Steps 1, 2, or 3 of the interstate transport framework in this action. Nor would it reopen any aspects of implementation of the program at Step 4 except for those in relation to establishing an auction and associated adjustments to ensure program stringency is maintained. In this respect, such a rulemaking would constitute a discretionary action that is not necessary to resolution of good neighbor obligations. Rather, these adjustments, if finalized, would reflect a shift from one acceptable form of implementation at Step 4 to a slightly modified but also acceptable form of implementation at Step 4, as related to EGUs. No legal or technical justification for this action as set forth in the record here depends on or would be undermined by the development of an alternative approach that includes an auction, and if the EPA for any reason determines not to propose or finalize such a rulemaking, no aspect of this rule would thereby be rendered infeasible or incomplete.

[308] CSAPR and the CSAPR Update both applied to EGUs located in areas within Oklahoma's borders that are now understood to be Indian country, consistent with the U.S. Supreme Court's decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020) (and subsequent case law), clarifying the extent of certain Indian country within Oklahoma's borders. However, those rules were issued before the *McGirt* decision. *See* section III.C.2.a.

states—Alabama, Minnesota, and Wisconsin—for which the EPA is determining that the required control stringency does not include such measures. In previous rulemakings, the EPA has chosen to combine states in a single multi-state trading program only where the selected control stringencies were comparable, to ensure that states did not effectively shift their emissions reduction requirements to other states with less stringent emissions reduction requirements by using net out-of-state purchased allowances. Although the assurance provisions in the CSAPR trading programs were designed to address the same general concern about excessive shifting of emissions reduction activities between states, EPA chose not to rely on the assurance provisions as sufficient to allow for interstate trading in situations where the states were assigned differing emissions control stringencies.

In this rulemaking, the EPA believes the previous concern about the possibility that certain states might not make the required emissions reductions is sufficiently addressed through the various enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions are being substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in sections VI.B.1.c.ii and VI.B.8. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in sections VI.B.1.c.i and VI.B.7 will necessarily also ensure that required emissions reductions occur within the state. With these enhancements to the design of the trading program, the EPA does not believe it is necessary for sources in Alabama, Minnesota, and Wisconsin to be excluded from the revised Group 3 trading program simply because their emissions budgets reflect a different selected emissions control stringency than the other states in the program.

The EPA's legal and analytic bases for expansion of the Group 3 trading program to each of the additional covered states, as well as responses to the principal related comments, are discussed in sections III, IV, and V of this document, respectively, and responses to additional comments are contained in the *RTC* document. With respect to the proposed approach of including all states covered by the rule in a single trading program even where the assigned control stringencies differ, the only comments received by the EPA supported the approach, which is finalized as proposed.

3. Applicability and Tentative Identification of Newly Affected Units

The Group 3 trading program generally applies to any stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine located in a covered state (or Indian country within the borders of a covered state) and serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW and producing electricity for sale, with exemptions for certain cogeneration units and certain solid waste incineration units. To qualify for an exemption as a cogeneration unit, an otherwise-affected unit generally (1) must be designed to produce electricity and useful thermal energy through the sequential use of energy, (2) must convert energy inputs to energy outputs with efficiency exceeding specified minimum levels, and (3) may not produce electricity for sale in amounts above specified thresholds. To qualify for an exemption as a solid waste incineration unit, an otherwise-affected unit generally (1) must meet the CAA section 129(g)(1) definition of a "solid waste incineration unit" and (2) may not consume fossil fuel in amounts above specified thresholds. The complete text of the Group 3 trading program's applicability provisions and the associated definitions can be found at 40 CFR 97.1004 and 97.1002, respectively. The applicability of this rule to MWCs and cogeneration units outside the Group 3 trading program is discussed in sections V.B.3.a and V.B.3.c of this document, respectively, and MWC applicability criteria are further discussed in section VI.C.6 of this document.

In this rulemaking, the EPA did not propose and is not finalizing any revisions to the existing applicability provisions for the Group 3 trading program. Thus, any unit that is located in a newly added state and that meets the existing applicability criteria for the Group 3 trading program will become an affected unit under the program. The fact that the applicability criteria for all of the CSAPR trading programs are identical therefore is sufficient to establish that any units that are currently required to participate in another CSAPR trading program in any of the additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin (including Indian country within the borders of such states)—will also become subject to the Group 3 trading program.

In the additional states where other CSAPR trading programs are not currently in effect—Nevada and Utah (including Indian country within the borders of such states)—units already subject to the Acid Rain Program under that program's applicability criteria (*see* 40 CFR 72.6) generally also meet the applicability criteria for the Group 3 trading program. Based on a preliminary screening analysis of the units in these states that currently report emissions and operating data to the EPA under the Acid Rain Program, the Agency believes that all such units are likely to meet the applicability criteria for the Group 3 trading program.

Because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical, it is possible that some units could meet the applicability criteria for the Group 3 trading program even if they are not subject to the Acid Rain Program. Using data reported to the U.S. Energy Information Administration, in the proposal the EPA identified six sources in Nevada and Utah (and Indian country within the borders of the states) with a total of 15 units that appear to meet the general applicability criteria for the Group 3 trading program and that do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program. These units were listed in a table in the proposed rule, and the data from that table for these units are reproduced as Table VI.B.3–1 of this document. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposed to use for the unit when determining state emissions budgets if the unit was ultimately treated as subject to the Group 3 trading program.[309] The EPA requested comment on whether each listed unit would or would not meet all relevant criteria set forth in 40 CFR 97.1004 and the associated definitions in 97.1002 to qualify for an exemption from the trading program and whether the estimated historical heat input and emissions data identified for each unit

[309] As discussed in section VI.B.10, any unit that becomes subject to the Group 3 trading program pursuant to this rule and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 will not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, in order to provide time for installation and certification of the required monitoring systems. Such a unit will not be taken into account for purposes of determining state emissions budgets and unit-level allocations under the Group 3 trading program until the 2024 control period.

were representative. With respect to the listed units within the borders of Nevada or Utah, the EPA received no comments asserting either that the units qualified for applicability exemptions or that the estimated data identified by the EPA were unrepresentative.[310] For purposes of this rule, the EPA is therefore presuming that the units listed in Table VI.B.3–1 do not qualify for applicability exemptions and that the estimated data shown in the table for each unit are representative. However, the owners and operators of the sources retain the option to seek applicability determinations under the trading program regulations at 40 CFR 97.1004(c).

TABLE VI.B.3–1—ESTIMATED DATA TO BE USED FOR PRESUMPTIVELY AFFECTED UNITS WITHIN THE BORDERS OF NEVADA AND UTAH THAT DO NOT REPORT UNDER THE ACID RAIN PROGRAM

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Nevada	2322	Clark	GT4	CT	190,985	0.0475	
Nevada	2322	Clark	GT5	CT	1,455,741	0.0191	
Nevada	2322	Clark	GT6	CT	1,455,741	0.0187	
Nevada	2322	Clark	GT7	CT	1,455,741	0.0178	
Nevada	2322	Clark	GT8	CT	1,455,741	0.0204	
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTA	CT	660,100	0.0377	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTB	CT	660,100	0.0387	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTC	CT	660,100	0.0387	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTA	CT	749,778	0.0323	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTB	CT	749,778	0.0370	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTC	CT	749,778	0.0364	1
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	1
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	1
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	

Table notes:
[1] Unit reports capability of producing both electricity and useful thermal energy.

4. State Emissions Budgets

In this final rule, the EPA is using a combination of a "preset" budget calculation methodology and a "dynamic" budget calculation methodology to establish state emissions budgets for the Group 3 trading program. A "preset" budget is one for which the absolute amount expressed as tons per ozone season control period is established in this final rule. It uses the latest data currently available on EGU fleet composition at the time of this final action. A "dynamic" budget is one for which the formula and emissions-rate information is finalized in this rule, but updated EGU heat input and inventory information is used on a rolling basis to set the total tons per ozone season for each control period. Both methods of budget calculation are designed to set budgets reflective of the emissions control strategies and associated stringency levels (expressed as an emissions rate of pounds of NO_X per mmBtu) identified for relevant EGU types at Step 3—which we will refer to in this section as the "Step 3 emissions control stringency." Preset budgets provide greater certainty for planning purposes and can be reliably established in the short-term based on known, upcoming changes in the EGU fleet. Due to build time for new units and planning and approval processes for plant retirements, these major fleet alterations are often known several years in advance. This information facilitates presetting budgets that appropriately calibrate the identified control stringency to the fleet. Dynamic budgets better assure that the budgets remain commensurate with the Step 3 emissions control stringency over the longer term, as currently unknown changes in the EGU fleet occur. In this final rule, in response to comments, we have adjusted the proposal to give a greater role for preset budgets through 2029, while dynamic budgeting will be phased in to provide greater certainty in the short term and allow for a transition period to an exclusively "dynamic" approach beginning in 2030.

For the control periods from 2023 through 2025, the preset budgets established in the rule will serve as the state emissions budgets for the control periods in those years, with no role for dynamic budgeting. For the control periods from 2026 through 2029, the EPA is determining preset emissions budgets for each control period in the rule and will also calculate and publish dynamic budgets for each state in the year before each control period using the dynamic budget-setting methodology finalized in this rule, applied to data available at the time of the calculations. For these four control periods, each state's preset budget serves as a floor and may be supplanted by the dynamic emissions budget EPA calculates for the state for that control period only if the dynamic budget is higher than the preset budget. For control periods in 2030 and thereafter, the state emissions budgets will be the dynamic budgets calculated and published in the year before each control period.

In the dynamic budget calculation methodology, it is the fleet composition (reflected by heat input patterns across the fleet in service, inclusive of EGU entry and exit) that is dynamic, while the emissions stringency finalized in this rule is constant, as reflected in

[310] One commenter expressed the view that eight of the listed units within Nevada's borders appear to meet the CSAPR applicability criteria but provided no comments on the specific proposed data. See comments of Berkshire Hathaway Energy, EPA–HQ–OAR–2021–0668–0554, at 58–59. The EPA also received comments concerning sources within Delaware's borders that were included in the proposal's request for comment; these comments are moot because Delaware is not being added to the Group 3 trading program in the final rule. See comments of Calpine, EPA–HQ–OAR–2021–0668–0515; comments of Delaware City Refining, EPA–HQ–OAR–2021–0668–0309.

emissions rates for various types of units. Multiplying the assumed emissions rate for each unit (as finalized in this rule) by the identified recent historical heat input for each unit and summing the results to the state level would provide a given year's state dynamic emissions budgets. Dynamic budgets are a product of the formula promulgated in this action applied to a rolling three-year average of reported heat input data at the state level and a rolling highest-three-of-five-year average of reported heat input data at the unit level. As such, the EPA is confident that dynamic budgets will more accurately reflect power sector composition, particularly in later years, and certainly from 2030 and beyond, than preset budgets could and will therefore better implement the Step 3 emissions control stringency over long time horizons.

Starting in 2025 (for the 2026 control period), the dynamic budgets, along with the underlying data and calculations will be publicly announced, and this will occur approximately one year before the relevant control period begins. These will be published in the **Federal Register** through notices of data availability (NODAs), similar to how other periodic actions that are ministerial in nature to implement the trading programs are currently handled. And as with such other actions, interested parties will have the opportunity to seek corrections or administrative adjudication under 40 CFR part 78 if they believe any data used in making these calculations, or the calculations themselves, are in error.

To illustrate how dynamic budgeting will work after the transition from preset budgets, the dynamic budgets for the 2030 ozone season control period will be identified by May 1, 2029, using the latest available average of three years of reported operational data at that time (*i.e.,* the average of 2026–2028 heat input data at the state level and 2024–2028 years of rolling data at the unit level) applied in a simple mathematical formula finalized in this rule, which multiplies this heat input data by the emissions rates quantified in this rule. Therefore, if a unit retires before the start of the 2028 ozone season but had not announced its upcoming retirement at the time of this rule's finalization, the dynamic budget approach ensures that the dynamic budgets for 2030 and subsequent control periods would represent the identified control stringency applied to a fleet reflecting that retirement.

The two examples discussed next illustrate the implementation of the dynamic budget during the 2026–2029 time period. During this period, the state emissions budget for each state for a given control period will be the preset state emissions budget unless the dynamic budget is higher. This approach accommodates scenarios where baseline fossil heat input may exceed levels anticipated by EPA in the preset budgets (*e.g.,* this could result from greater electric vehicle penetration rates). Table VI.B.4–1 illustrates this scenario. In the preset budget approach for 2028, the 2028 heat input is estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021; see the subsection on preset budget methodology later in this section), which cannot reflect a subsequent change in fleet heat input values (column 2) due to, *e.g.,* increased utilization to meet increased electric load. However, the dynamic budget would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet utilization levels, and when multiplied by the emissions rates reflecting the Step 3 emissions control stringency in this final rule, the corresponding emissions (18,700 tons) summed in column 4 constitute a state budget that more accurately reflects the Step 3 emissions control stringency applied to the fleet composition for that year, as opposed to the 17,000 tons identified in the preset budget approach. As illustrated in the example, the dynamic variable is the heat input variable, which changes over time. In this instance, the dynamic budget value of 18,700 tons would be implemented for 2028 instead of the preset value, and thus accommodate the unforeseen utilization changes in response to higher demand.

In the second table, Table VI.B.4–2, the dynamic budget is lower than the preset budget due to retirements that were not foreseen at the time the preset budgets were determined. In the preset budget approach for 2028, the 2028 heat input is still estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021), which cannot reflect a subsequent fleet change in heat input values due to an unanticipated retirement of one of the state's coal-fired units before the start of the 2028 ozone season. However, the dynamic budget again would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget, which would reflect the decline in coal heat input and replacement with natural gas heat input (capturing the coal unit's retirement). Therefore, the heat input values under the dynamic budget scenario reflect the change in fleet composition, and when multiplied by the relevant emissions rates reflecting the Step 3 emissions control stringency identified in this final rule, the corresponding emissions (15,000 tons) constitute a state budget that reflects the identified control stringency applied to the fleet composition for that year as opposed to the 17,000 tons in summed in the first table. However, for the 2026–2029 period, in which the EPA implements an approach that utilizes the higher of the dynamic budget or preset budget, the budget implemented for 2028 in this scenario would be the 17,000 ton preset amount.

During the 2026–2029 transition period—during which substantial, publicly announced utility commitments exist for higher emitting units to exit the fleet—it is still possible that yet-to-be known, unit-specific retirements (such as illustrated in this second scenario) may result in dynamic budgets that are lower than the preset budgets finalized in this rule. However, during this transition period EPA believes that having the preset budgets serve as floors for the state emissions budgets is appropriate for two primary reasons identified by commenters. First, commenters repeatedly emphasized the need for certainty and flexibility to successfully carryout plans for significant fleet transition through the end of the decade. The 2026–2029 period is expected to have substantial fleet turnover. Current Form EIA–860 data, in which utilities report their retirement plans, identify 2028 as the year with the most planned coal capacity retirements during the 2023–2029 timeframe. Using preset budgets as state emissions budget floors provides states and utilities with information on minimum quantities of allowances that can be used for planning purposes. In turn, this fosters the operational flexibility needed while putting generation and transmission solutions into place to accommodate such elevated levels of retirements. Second, the latter part of the decade has a significant amount of unit-level firm retirements already planned and announced for purposes of compliance with other power sector regulations or fulfillment of utility commitments. These known retirements are already captured in the preset state budgets, with the result that the likelihood and magnitude of instances where a state's dynamic budget for a given control period would be lower than its preset budget for the control period is reduced in this 2026–2029 period relative to control periods further in the future for which retirement plans have not yet been announced. After 2029, the dynamic budgets from 2030 forward will fully capture all prior retirements and new builds when the fleet is entering this period where unit-specific data on such plans is less frequently available. For instance, through the remaining portion of the decade, the amount of coal steam retirements identified and reported through Form EIA–860 is nearly 7 GW each year. However, for the decade beginning in 2030—the amount of capacity currently reported with a planned retirement is less than 2 GW each year.[311] This yet-to-be available data and relative lack of currently known firm retirement plans for 2030 and beyond make dynamic budget implementation for those years essential for state emissions budgets to maintain the Step 3 control stringency required under this rule.

TABLE VI.B.4–1—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF INCREASED FOSSIL HEAT INPUT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	660	0.05	16,500
Gas Units	400	0.01	2,000	440	0.01	2,200
State Budget (tons)			17,000			18,700

TABLE VI.B.4–2—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF UNANTICIPATED RETIREMENT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	500	0.05	12,500
Gas Units	400	0.01	2,000	500	0.01	2,500
State Budget (tons)			17,000			15,000

In summary, for the control periods in 2023 through 2025, EPA is providing only preset budgets in this final rule because those control periods are in the immediate future and would not substantially benefit from the use of future reported data. For these years, the certainty around new builds and retirements is higher than ensuing years. For the ozone season control periods of 2026 through 2029, EPA is providing both preset budgets in this final rule and dynamic budgets via future ministerial actions. For those control periods from 2026 through 2029, the preset budgets finalized in this rule serve as floors, such that a given state's dynamic budget ultimately calculated and published for that control period will apply to that state's affected EGUs only if it is higher than the corresponding preset budget finalized in this rulemaking. This approach is in response to stakeholder comments requesting more advance notice regarding the total quantities of allowances available to accommodate compliance planning through the latter half of the decade, during a period of particularly high fleet transition expected with or without this rulemaking.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Final Rule TSD and summarized later in this section.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 Through 2029 Control Periods

To compose preset state emissions budgets, the EPA is using the best available data at the time of developing this final rule regarding retirements and new builds. The EPA relies on a compilation of data from Form EIA–860 (where facilities report their future retirement plans), the PJM Retirement Tracker, utilities' integrated resource plans, notification of compliance plans with other EPA power sector regulatory requirements, and other information sources that EPA routinely canvasses to populate the data fields included in the Agency's NEEDS database. The EPA has updated this data on retirements and new builds using the latest information available from these sources at the time of final rule development as well as input provided by commenters.

For determining preset state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data available to EPA and to commenters responding to this rulemaking's proposal and providing a reasonable representation of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update and the Revised CSAPR Update, where

[311] See 2021 Form EIA Form 860—Schedule 3, Generator Data. Department of Energy, Energy Information Administration.

the EPA likewise began with data for the most recent ozone season at the time of proposal (2015 and 2019, respectively).

By using historical unit-level NO_X emissions rates, heat input, and emissions data in the first stage of determining preset emissions budgets, the EPA is grounding its budgets in the most recent representative historical operation for the covered units at the time EPA began its final rulemaking. This data set is a reasonable starting point for the budget-setting process as it reflects recent publicly available and quality assured data reported by affected facilities under 40 CFR part 75, largely using CEMS. The reporting requirements include quality control measures, verification measures, and instrumentation to best record and report the data. In addition, the designated representatives of EGU sources are required to attest to the accuracy and completeness of the data.

The first step in deriving the future year state emissions budget is to calibrate historical data to planned future fleet conditions. EPA does this by adjusting this historical baseline information to reflect the known changes (*e.g.,* when deriving the 2023 state emissions budget, EPA starts by adjusting 2021 unit-level data to reflect changes announced and planned to occur by 2023). The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes expected to occur in the baseline. This includes announced and confirmed retirements, new builds, and retrofits that occur after 2021 but prior to 2023. For example, if a unit emitted in 2021, but retired prior to May 1, 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the EPA uses the actual emissions, heat input, and emissions rates reported for 2021 as the baseline starting point for calculating the 2023 state emissions budgets. Using this method, the EPA arrived at a baseline emission, heat input, and emissions rate estimate for each unit for a future year (*e.g.,* 2023).

The second step in deriving the preset state emissions budgets is for EPA to take the adjusted historical data from Step 1, and adjust the emissions rates and mass emissions to reflect the control stringencies identified as appropriate for EGUs of that type. For instance, if an SCR-equipped unit was not operating its SCR so as to achieve a seasonal average emissions rate of 0.08 lb/mmBtu or less in the historical baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's mass emissions. Note that the heat input is held constant for the unit in the process, reflecting the same level of unit operation compared to historical 2021 data. The improved emissions rate of 0.08 lb/mmBtu is applied to this constant heat input, reflecting control optimization. In this manner, the unit-level totals from Step 1 are adjusted to reflect the additional application of the assumed control technology at a given control stringency. This is illustrated in Table VI.B.4.a–1. Row 1 reflects the 2021 historical data for this SCR-controlled unit. Row 2 reflects no change (as there are no known changes such as planned retirement or coal-to-gas conversion). Row 3 reflects application of the Step 3 stringency (*i.e.,* a 0.08 lb/mmBtu emissions rate from SCR optimization). The resulting impact on emissions is a reduction from the historical 4,700 tons to an expected future level of 615 tons. A state's preset budget for a given control period is the sum of the amounts computed in this manner for each unit in the state for the control period.

TABLE VI.B.4.a–1—EXAMPLE OF UNIT-LEVEL DATA CALCULATIONS FOR DERIVING STATE EMISSIONS BUDGETS

	Heat input (tBtu)	Emission rate (lb/mmBtu)	Emissions (tons)
Historical Data (2021)	15.384	0.61	4,700
Step 1 (Baseline)—Historical data adjusted for planned changes	15.384	0.61	4,700
Step 2—Baseline further adjusted for Step 3 stringency	15.384	0.08	615

For each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Minnesota, and Wisconsin will reflect the selected control stringency that incorporates post-combustion control retrofit opportunities for the relevant units identified in the state emissions budgets and calculations appendix to the Ozone Transport Policy Analysis Final Rule TSD. The emissions rates assigned to large coal-fired EGUs for 2026 state emissions budget computations only reflect 50 percent of the SCR retrofit emissions reduction potential at each of those units, to capture the phase-in approach EPA is taking for this control as described in section VI.A of this document. The EPA calculates these unit-level emissions rates in 2026 as the sum of the unit's baseline emissions rate and its controlled emissions rate divided by two (*i.e.,* 50 percent of the emissions reduction potential of that pollution control measure). The emissions rates assigned to these large coal-fired EGUs for 2027 state emissions budget computations reflect the full assumed SCR retrofit emissions potential at those units, by applying the controlled emissions rate only. For example, a coal steam unit greater than or equal to 100 MW currently lacking a SCR and emitting at 0.20 lb/mmBtu would be assumed to reduce its emissions rate to 0.125 lb/mmBtu rate in 2026 and 0.050 lb/mmBtu rate in 2027 for purposes of deriving its preset state emissions budgets in those years.

Comment: Some commenters suggested that EPA should not reflect planned retirements in its preset budgets. The suggestion stems from commenters' observation that those retirement decisions may yet change.

Response: The effectiveness of EPA's future year preset state emissions budgets depends on how well they are calibrated to the expected future fleet. Therefore, EPA believes it is important to incorporate expected new builds, retirements, and unit changes already slated to occur. Ignoring these factors would dilute, rather than strengthen, the ability of preset budgets to capture the most representative fleet of EGUs to which they will be applied. Omitting scheduled retirements and new builds from state emissions budgets would reflect units that power sector operators and planning authorities do not expect to exist, while failing to reflect units that are expected to exist.

EPA notes it is using the best available data at the time of the final rule. EPA relies on a compilation of data from Form EIA–860 where facilities report their future retirement plans. In addition, EPA is using data from regional transmission organizations who are cataloging, evaluating, and approving such retirement plans and data; data from notifications submitted directly to EPA by the utility themselves through comments; and retirement notifications submitted to permitting authorities. This information is highly reliable, real-world information that provides EPA with the high confidence that such retirements will in fact occur.

If a unit's future retirement does not occur on the currently scheduled date, EPA observes that such an unexpected departure from the currently available evidence would still not undermine the ability of affected EGUs to comply with their applicable state budgets. EPA's approach of using historical data and incorporation only of announced fleet changes in estimating its future engineering analytics baseline means that its future year baseline generation and retirement outlook for higher emitting sources is more likely to understate future retirements (rather than overstate as suggested by commenter), as EPA does not assume for the purpose of preset budget quantification any retirements beyond those that are already planned. In other words, in the 2023 through 2029 timeframe for which EPA is establishing preset state emissions budgets in this rulemaking, there are more likely to be additional future EGU retirements beyond those scheduled prior to the finalization of this rule than there are to be reversed or substantially delayed changes to already announced EGU retirement plans. For instance, subsequent to the EPA's finalization of the Revised CSAPR Update Rule budgets for 2023 (rule finalized in March 2021), the owners of Sammis Units 5–7 and Zimmer Unit 1 in Ohio (totaling nearly 3 GW of coal capacity) announced that the units would retire by 2023—nearly 5 years earlier than previously planned.[312] [313] These coal retirements were not captured in Ohio's 2023 or 2024 state emissions budgets established under the Revised CSAPR Update. Meanwhile, there have been no announcements of previously announced retirement plans being rescinded or delayed for other Ohio units. Similarly, the Joppa Power Plant in Illinois accelerated its retirement from 2025 to 2022 shortly after the Revised CSAPR Update Rule was signed.[314]

We further observe that the commenters' concern is only materially meaningful for the 2023 through 2025 preset budget periods, where the currently known information is generally the most reliable. For the 2026–2029 control periods, if an anticipated fleet change such as an EGU retirement does not actually occur, the dynamic budget setting methodology would, all else being equal, generate a budget reflective of that unit's continued operation (as the budget would be based on the preceding years of historical data), and that dynamic budget will supplant the preset budget for that state (if it represents a total quantity of emissions higher than the preset budget).

Because the future is inherently uncertain, all analytic tools and information resources used in any estimation of future EGU emissions will yield some differences between the projected future and the realized future. Such potential differences may either increase or decrease future emissions in practice, and the unavoidable existence of such differences does not, on its own, render the EPA's inclusion of currently announced retirements an unreasonable feature of the methodology for determining future year preset emissions budgets. To the contrary, if the EPA failed to include these announced retirements, the rule would knowingly authorize amounts of additional, sustained pollution that are not currently expected to occur. If those retirements largely or entirely occur as currently scheduled, the overestimated state budgets would allow other EGUs to emit additional pollution in place of the emissions from the retired EGUs instead of maintaining or improving their emissions performance to eliminate significant contribution with nonattainment and interference with maintenance of the NAAQS.[315]

Additionally, as noted elsewhere, EPA's use of a market-based program, a starting bank of converted allowances, and variability limits are all features that will readily accommodate whatever relatively limited differences in emissions may occur if a currently scheduled EGU retirement is ultimately postponed during the preset budget years of 2023 through 2025. Therefore, EPA's resulting preset state emissions budgets—inclusive of expected fleet turnover—are robust to the inherent uncertainty in future year baseline conditions for the period in which they are applied.

Comment: Some commenters suggested that EPA should use a multi-year baseline for all of its state budget derivations, including preset budgets, to control for outlier years that may not be representative of future years due to major weather events or other fleet disruptions (such as a large nuclear unit outage).

Response: For preset state emissions budget derivation, EPA is finalizing use of the same single-year[316] historical baseline approach it used in the proposed rule. This approach is similar to the Revised CSAPR Update, where EPA also relied on a single-year historical baseline to inform its Step 3 approach. EPA's interest in a historical data set to inform this part of the analysis is to capture the most representative view of the power sector. For estimating preset state budgets, EPA finds that, particularly at the state level, more recent data is a better representation and basis for future year baselines rather than incorporating older data. Taking as an example preset budget estimation for the 2023 through 2025 ozone seasons, the EPA is able to compare its single-year base line to an alternative multi-year baseline (*e.g.,* a 3-year baseline encompassing 2020–2022) and determine that the single year baseline better reflects future fleet operation expectation than a multi-year baseline that incorporates units which have since retired as well as outlier patterns in load during pandemic-related shutdowns.

EPA recognizes that 2021 is the latest available historical data as of the preparation of this rulemaking, and therefore the most up-to-date picture of the fleet at the time EPA began its analysis. EPA then further evaluates the 2021 historical data at the state level to determine whether it was a representative starting point for estimating future year baseline levels and subsequently deriving the preset state emissions budgets. If the Agency finds any state-level anomalies, it makes necessary adjustments to the data. While unit-level variation may occur from year-to-year, those variations are often offset by substitute generation from other units within the state. Therefore, EPA conducts its first screening at the state level by identifying any states where 2021 heat

[312] Available at *https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html.*

[313] Available at *https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/071921-vistra-plans-to-retire-13-gw-zimmer-coal-plant-in-ohio-five-years-early.*

[314] Available at *https://www.prnewswire.com/news-releases/joppa-power-plant-to-close-in-2022-as-company-transitions-to-a-cleaner-future-301263013.html.*

[315] Some of these announced retirements reflect the operator's reported intention to EPA to retire the affected capacity by that time as part of their compliance with effluent limitation guidelines or with the coal combustion residuals rule.

[316] For the purposes of this rulemaking, when describing a "year" or "years" of data utilized in state emission budget computations, the EPA is actually utilizing the relevant data from May 1 through September 30 of the referenced year(s), consistent with the control period duration of this rule's EGU trading program.

input and 2021 emissions were the lowest year for heat input and emissions relative to the past several years (2018–2022, excluding 2020 due to shut downs and corresponding reduced utilization related to the pandemic onset).[317] [318] Then, for that limited number of states (AL, LA, MS, and TX) in which 2021 reflects the minimum fossil fuel heat input and minimum emissions over the baseline evaluation period, EPA—similar to prior rules—evaluated whether any unit-level anomalies in operation were driving this lower heat input at the state level. EPA examined unit-level 2021 outages to determine where an individual unit-level outage might yield a significant difference in state heat input, corresponding emissions baseline and resulting state emissions budgets. When applying this test to all of the units in the previously identified states (and even when applying to EGUs in all states for whom Federal implementation plans are finalized in this rulemaking), the EPA determined that the only unit with a 2021 outage that (1) decreased its output relative to preceding or subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's emissions budget substantially as it constituted more than 5 percent of the state's heat input in a non-outage year was Daniel Unit 2 in Mississippi. EPA therefore adjusted this state's baseline heat input and NO_X emissions to reflect the operation of this unit based on its 2019 data—which was the second most recent year of data available at the time of proposal (excluding 2020 given atypical impacts from pandemic-related shutdowns) for which this unit operated. The EPA then applied the Step 3 mitigation strategies as appropriate to this unit (*i.e.*, combustion controls upgrade in 2024, SCR retrofit in 2026/2027) to derive this portion of Mississippi's budget. This test, and subsequent adjustment as necessary, enables EPA to utilize the latest, most representative data in a manner that is robust to any substantial state-level or region-level outlier events within that dataset and further validates EPA's comprehensive approach to using the most recent single year of data for preset budgets.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2026 onwards

In this final rule, the EPA is finalizing an approach of using multi-year baseline data for purposes of dynamic budget computation. The aforementioned testing of the representative nature of a single year of baseline data for purposes of preset budget setting is not possible in the dynamic budget process as that data will not be available until a later date. Further, the EPA generally agrees with commenters that use of a multi-year period will be more robust to any unrepresentative outlier years in fleet operation and thus better suited for purposes of dynamic budgets. The methodology for determining dynamic state emissions budgets for later control periods (2026 and beyond) relies on a nearly identical methodology for applying unit-level emissions rate assumptions as the preset budget methodology. But it uses more recent heat input data that will become available by that future time, employing a multi-year approach for identifying the heat input data so as to ensure representativeness.

For dynamic budgets, EPA uses more years of baseline data to control for any state-level and unit-level variation that may occur in a future single year that is not possible to identify at present. First, for each unit operating in the most recent ozone season for which data have been reported, EPA identifies the average of the three highest unit-level heat input values from the five ozone seasons ending with that ozone season to get a representative unit-level heat input. Ozone seasons for which a unit reported zero heat input are excluded from the averaging of the three highest heat input values for that unit. These representative unit-level heat input values established for each unit individually are then summed for all units in each state. Each unit's representative unit-level heat input is then divided into this state-level sum to get that unit's representative percent of the aggregated average heat input values for all affected EGUs in that state.

Next, EPA calculates a representative state-level heat input by taking the average state-level total heat input across affected EGUs from the most recent three ozone seasons for which data have been reported, to which the above-derived representative unit-level percentages of heat input are applied. The EPA uses a three-year baseline period for state-level heat input versus the five-year baseline period noted previously for unit-level heat input because there is less variation from year to year at the state level compared to the unit level. Multiplying the representative unit-level percentages of heat input by the representative state-level heat input yields a normalized unit-level heat input value for each affected EGU. This step assures that the total heat input being reflected in a dynamic state budget does not exceed the average total heat input reported by affected EGUs in that state from the three most recent years. Finally, each normalized unit-level heat input value is multiplied by the emissions rate reflecting the assumed unit-specific control stringency for each particular year (determined at Step 3) to get a unit-level emissions estimate. These unit-level emissions estimates are then summed to the state level to identify the dynamic budget for that year. This procedure to derive normalized unit-level heat input is captured in the following table:

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
Unit A	100	200	150	200	300	233	41%	483	199
Unit B	50	100	200	50	100	133	24	483	114
Unit C	250	150	150	200	100	200	35	483	170

[317] EPA identified states for which 2021 both heat input and emissions were the low year among the examined baseline period as a preliminary screen to identify potential instances where reduced utilization may lead to an understated emissions baseline value.

[318] EPA also conducted a similar test to identify states in which 2021 heat input and emissions were the high year among the examined baseline period and found that it was for both Utah and Pennsylvania. However, for both states the elevated heat input trend persisted into 2022 (at slightly lower levels and was correlated with retirements elsewhere in the region—indicating that some of this heat input increase may be representative of the future fleet and that planned retirements factored into preset budget will remove any unrepresentative heat input from 2021.

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT—Continued
[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
State Total	400	450	500	450	500	567			

The EPA will issue these dynamic budget quantifications approximately 1 year before the relevant control period. We view such actions as ministerial in nature in that no exercise of agency discretion is required. For instance, starting in early 2025, the EPA would take the most recent three years of state-level heat input data and the most recent five years of unit-level heat input data and calculate 2026 state emissions budgets using the methodology described previously. For 2026–2029, EPA is establishing the preset state emissions budgets finalized in this rulemaking and will only supplant those preset emissions budgets with the to-be-published dynamic emissions budgets if, for a given state and a given control period, that dynamic budget yields a higher level of emissions than the corresponding preset budget finalized in this rulemaking. For 2030 and beyond, the EPA solely uses the dynamic budget process.

By March 1 of 2025, and each year thereafter, the EPA will make publicly available through a NODA the preliminary state emissions budgets for the subsequent control period and will provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. (This process will be similar to the releases of data and preliminary computations for allocations from new unit set-asides that is already used in existing CSAPR trading programs.) By May 1 of 2025, and each year thereafter, the EPA will publish the dynamic budgets for the ozone-season control period in the following calendar year. Through the 2029 ozone season control period, these budgets will only be imposed if the applicable dynamic state budget is higher than the corresponding preset state budget finalized in this rulemaking. Preliminary and final unit-level allowance allocations for the units in each state in each control period will be published on the same schedule as the dynamic budgets for the control period. For the control periods from 2026 through 2029, the allocations will reflect the higher of the preset or dynamic budget for each state, and after 2030, the allocations will reflect the dynamic budgets. Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Final Rule TSD.

Comment: Multiple commenters claimed that designing a dynamic budget process that relies on a single year of yet-to-be known heat input data may produce an unrepresentative view of fleet operations for the immediate ensuing years. Commenters pointed to the hypothetical of another pandemic-like year (*e.g.,* 2020) occurring in the future, noting that 2020 would have been a poor choice for estimating 2022 fleet operation and the same would likely hold true if a similar event occurred, for example, in 2025—that would consequently make that year a poor choice as a representative of 2027 baseline. They further pointed out that severe weather events and operating disruptions (a large nuclear plant outage) can similarly render a single year baseline a risky choice to inform future expectations.

Response: Insofar as the commenters are addressing the reference period for dynamic budget computation regarding years of data that have not yet occurred and therefore not currently available for evaluating their representative nature, EPA agrees and is incorporating a rolling 3-year baseline at the state level and a rolling 5-year baseline at the unit level for determining dynamic budgets in this final rule. These multi-year rolling baseline (or reference periods) will minimize any otherwise undue impact from individual years where fleet-level or unit-level heat input was uncharacteristically high or low. EPA determined that such an approach, while not needed for preset budgets, is necessary in the case of dynamic budgets because the baseline in that instance is occurring in a future year and therefore is not knowable and available to test for representativeness at the time of the final rule. To control for this type of uncertainty, the EPA finds it appropriate to use a multi-year baseline in this instance per commenter suggestion. While a multi-year baseline may have a slight drawback of using a slightly more dated past fleet performance (including emissions from higher emitting EGUs that may have subsequently reduced utilization by the target year for which the dynamic budget is being calculated) to estimate the expected future fleet performance at the emissions performance levels determined by the Step 3 result in this rulemaking, that drawback is worth the advantage of protecting against instances where atypical circumstances in the most recent single year may occur and not be representative of the subsequent year for which the dynamic budget is being estimated. This singular drawback of moving to a multi-year baseline is most pronounced in the early years of dynamic budgeting. Therefore, EPA is able to lessen the impact of this drawback of the multi-year baseline by extending the earliest start date of dynamic budgets from 2025 (as proposed) to 2026 in the final rule.

Comment: Commenters suggested that the dynamic budget procedure would not provide enough advance notice of state budget and unit level allocation for sources to adequately plan future year operation.

Response: EPA disagrees with the notion that the timing of the dynamic budget determination would occur too close to the control period to allow adequate operations planning for compliance. As described previously, the dynamic budget level would be provided approximately 1 year in advance of the start of the control period (*i.e.,* around May 1), and the allowance allocations would occur on July 1, approximately 10 months prior to the start of the compliance period. Not only is this an adequate amount of time as demonstrated by the successful implementation of past rules that have been finalized and implemented within several months of the beginning of the first affected compliance period (*e.g.,* Revised CSAPR Update), but EPA notes it is maintaining similar trading program flexibility and banking flexibilities of past programs which provide further opportunities for sources to procure allowances and plan for any future operating conditions. Finally, as noted previously, the EPA is providing preset budgets for the years 2023–2029, which serve as an effective floor on the state's ultimate emissions budget level for years 2026–2029, as states will receive the higher of the preset or dynamic budget for those years. This provision of certain preset state emissions budgets serving as a floor level for 2026–2029 should further assuage commenters' concerns regarding planning certainty about allowance allocations and state emissions budget levels during this period of power sector transition to cleaner energy sources.

Comment: Commenters raised concerns that there is a two-year lag in the dynamic budgets in that, for example, for the dynamic budget in the 2026 control period, the calculations will be based on heat input and inventory information reflective of data through 2024. Commenters contend that, if there is a much greater need for allowances for compliance due to unavoidable or unforeseen need for a higher amount of heat input than reflected in prior years' data, the budget for that control period will not reflect this need, and the allowances will only become available when the dynamic budget is calculated using that information (*i.e.,* 2025 data would be reflected starting in the 2027 dynamic budget). According to commenters, this lag could present a serious compliance challenge. Other commenters raised a concern in the opposite direction about the potential "slack" created by the lag time—meaning that as high-emitting units retire, their emissions and operation will still inform the state emissions budgets for additional years beyond their retirement due to the lag.

Response: The EPA recognizes there will be a data lag inherent in the computation of future year dynamic emissions budgets, because the dynamic budgets will reflect fleet composition and utilization data from recent previous control periods rather than the control periods for which the dynamic budgets are being calculated. This means that the resulting dynamic budgets will reflect a limited lag behind the actual pace of the EGU fleet's trends. However, on the whole, those trends are clearly toward more efficient and cleaner generating resources. Thus, the data lag on the whole will inure to the compliance benefit of EGUs by resulting in dynamic budgets that are generally calculated at levels likely to be somewhat higher than what a dynamic budget calculation reflecting real-time EGU operations would produce. The EPA believes this data lag is worthwhile to provide more compliance planning certainty and advance notice to affected EGUs of the dynamic budget applicable to an upcoming control period. Furthermore, this data lag in dynamic budget computation is comparable to the data lag of quantifying preset state budgets for 2023 through 2025 based upon 2021 data, and at no point in the long history of EPA's trading programs has such a data lag in state budget computation yielded any compliance problems for affected EGUs. Without dynamic budgeting, the data lag inherent in calculating preset budgets would grow unabated with the passage of time, as a fixed reference year of heat input levels would continually apply regardless of potentially higher heat input levels farther and farther into the future. By eliminating the increase in the length of the data lag, this new dynamic budgeting approach is a substantial improvement in performance of the program relative to previous approaches that were not capable of capturing changes over time in the fleet and its utilization beyond the scheduled changes known to the EPA at the time of establishing preset budgets.

The EPA disagrees that this lag will in fact pose compliance challenges for EGUs even if the unlikely scenario described by commenters were to occur. Several factors influence this. First, the change in methodology to preset budgets serving as a floor on budgets through 2029 means that the dynamic budget methodology can only produce an increase in the budget from this final rule through that year. Second, the adoption of a multi-year approach for identifying the heat input used to calculate the dynamic budgets will smooth the year-to-year budget changes and effectively eliminate the possibility of greatest concern, which was that a single year of unusually low heat input would be used to set the budget for a subsequent year that turned out to have unusually high heat input. While a year of unusually high heat input for a given state may still occur, the state's budgets for those years will never be based on heat input from an anomalously low year, but instead will always be based on an average of several years' heat input. Third, because the Group 3 trading program is an interstate program implemented over a wide geographic region, and it is unlikely that all regions of the country would uniformly experience a marked increase in fossil fuel heat input necessitating an additional supply of allowances, it is likely that allowances will be available for trade from one area of the country where there is less demand to another area where there is greater demand. Fourth, as explained in section VI.B.5 of this document, each state's assurance level will adjust to reflect actual heat input in that year. Specifically, the EPA will determine each state's variability limit for a given control period so that the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. Thus, if in year 2030, for example, a state's actual heat input levels increase to a level that is not reflected in the dynamic budget calculation using earlier years of data, the assurance level (which absent the unusually high heat input would be 121 percent of the state's budget) will be calculated by the EPA following the 2030 ozone season, using that higher reported heat input. This will avoid imposing a three-for-one allowance surrender penalty on sources except where emissions exceed the assurance level even factoring in the increase in heat input in that year. Finally, as some commenters observed, the inherent data lag in dynamic budget quantification means that a state budget for the year 2030 will continue to reflect emissions from any EGU that retires before the 2030 control period but is still operating anytime during the 2026–2028 reference years from which the 2030 dynamic budget will be calculated. Given the likely ongoing trend of relatively high-emitting EGU retirements over time, this method for determining dynamic budgets should further assist the ability of remaining EGUs to obtain sufficient allowances to cover future heat input levels.

With respect to the comments expressing concern that dynamic budgets would create too much slack because of the lag in incorporating retirements, the EPA observes that dynamic budgets will yield a closer representation of Step 3 control stringency across the future fleet than preset budgets for years in which retirement plans are currently relatively unknown. Moreover, any risk that the lag would lead to an unacceptably large surplus of allowances is limited by EPA's finalization of the annual bank recalibration to 21 percent and 10.5 percent of the budget beginning in 2024 and 2030 respectively. The corresponding risk that a lag will lead sources to not operate emissions controls, due to a surplus of allowances, is also limited by the backstop daily emissions rates that start in 2024 (for sources with existing SCR controls) and no later than 2030 for other coal-fired sources.

Comment: Commenters allege that the dynamic budget methodology is effectively a "one-way ratchet" because, if EGUs pursue compliance strategies such as reduced utilization or generation shifting to comply with the rule rather than install or optimize pollution controls pursuant to the identified Step 3 emissions control strategies, the effect will be that the dynamic budget calculated in a future year will reflect that reduced heat input, but the applied emissions rate assumption will be the same. Thus, the approach according to commenters actually ''punishes'' sources for achievement of emissions reductions commensurate with EPA's Step 3 determinations through alternative compliance means, by producing a smaller budget in later years (less heat input multiplied by the same emissions rate). If the source again reduces utilization or shifts generation to comply with this budget, then budgets in later years will again ratchet down, and so on.

Response: First, the claims of dynamic budgeting being a one-way ratchet are incorrect. As pointed out at proposal, the dynamic budget process would allow for increased utilization to result in increased budgets. Moreover, this concern is entirely mooted for the period 2026 through 2029 with the shift to preset budgets serving as a floor; dynamic budgeting can only increase the budget used in any given year in this time period. Additionally, the use of a multi-year average heat input in the budget-setting calculations will, on the whole, modulate the dynamic budgets such that the budgets over time will only gradually change with changes in the operating profile of the EGU fleet.

For the control periods 2030 and later, this rule is premised on the expectation that all large coal-fired EGU sources identified for SCR-retrofit potential will, if they continue operating in 2030 or later, have installed the requisite post-combustion controls. Thus, the backstop daily emissions rate applies for all such sources beginning in the 2030 ozone season. In this latter period (post-2030), the EPA disagrees that the dynamic budget will punish fleet segments seeking to continue to pursue a strategy of reduced utilization. Rather, the dynamic budget will simply continue to reflect the Step 3 emissions control stringency. For instance, if there are two otherwise high-emitting sources in a state that can reduce emissions by operating SCR, this rule's control stringency finds it cost effective for both sources to operate their controls. If one source retires and is replaced by new lower-emitting generation, it is not a punishment to have the budgets adjust in a way that still incentivize remaining units to operate their controls. This is simply right-sizing the budget to an evolving fleet. It is a feature of the rule, not a flaw, and is designed to address observed instances in prior rules where market-driven reduced utilization resulted in non-binding (*i.e.,* overly slack) budgets and corresponding conditions where the incentive to operate a control dissipated over time. In the event that sources reduce utilization whether for compliance purposes or market-driven reasons, that also does not obviate the importance of continuing to incentivize the Step 3 emissions control stringency at identified sources.

c. Final Preset State Emissions Budgets

For affected EGUs in each covered state (and Indian country within the state's borders), this final rule establishes preset budgets for the control periods 2023 through 2029. For control periods 2026 through 2029, any of those preset budgets may be supplanted by the corresponding dynamic budget that will be tabulated at later date, if and only if that dynamic budget yields a higher amount. For 2030 and beyond, the dynamic budget formula promulgated in this rule will be applied to future year data to quantify state emissions budgets for those control periods. The procedures for allocating the allowances from each state budget among the units in each state (and Indian country within the state's borders) are described in section VI.B.9 of this document. The amounts of the final preset state emissions budgets for the 2023 through 2029 control periods are shown in Table VI.B.4.c–1.

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS

[Tons] [a b]

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

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS—Continued

[Tons] [a] [b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

Table Notes:

[a] The state emissions budget calculations pertaining to Table VI.B.4.c–1 are described in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event this final rule becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period will be adjusted under the rule's transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date. The 2023 budget amounts shown in Table VI.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in section VI.B.12 of this document.

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program includes assurance provisions designed to limit the total emissions from the sources in each state (and Indian country within the state's borders) in each control period to an amount close to the state's emissions budget for the control period, consistent with the principle that each state's sources must be held to the elimination of significant contribution within that state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond sources' reasonable ability to control. For each state, the assurance provisions establish an assurance level for each control period, defined as the sum of the state's emissions budget for the control period plus a variability limit, which under the Group 3 trading program regulations in effect before this rulemaking was 21 percent of the relevant state emissions budget. The purpose of the variability limit is to account for year-to-year variability in EGU operations, which can occur for a variety of reasons including changes in weather patterns, changes in electricity demand, and disruptions in electricity supply from other units or from the transmission grid. Because of the need to account for such variability in operations of each state's EGUs, the fact that emissions from the state's EGUs may exceed the state's emissions budget for a given control period is not treated as inconsistent with satisfaction of the state's good neighbor obligations as long as the total emissions from the EGUs remain below the state's assurance level. Emissions from a state's EGUs above the state's emissions budget but below the state's assurance level are treated in the same manner as emissions below the state's emissions budget in that such emissions are subject to the same requirement to surrender allowances at a ratio of one allowance per ton of emissions. In contrast, emissions above the state's assurance level for a given control period are strongly discouraged as inconsistent with the state's good neighbor obligations and are subject to an overall 3-for-1 allowance surrender ratio. The establishment of assurance levels with associated extra allowance surrender requirements was intended to respond to the D.C. Circuit's holding in *North Carolina* requiring the EPA to ensure within the context of an interstate trading program that sources in each state are required to address their good neighbor obligations within the state and may not simply shift those obligations to other states by failing to reduce their own emissions and instead surrendering surplus allowances purchased from sources in other states.[319]

In this rulemaking, the EPA did not propose and is not making changes to the basic structure of the Group 3 trading program's assurance provisions, which will continue to set an assurance level for each control period equal to the state's emissions budget for the control period plus a variability limit and will continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[320] Each assurance level also will continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[321] However, the EPA is making a change to the methodology for determining the variability limits. Specifically, the EPA will determine each state's variability limit for a given control period so that, instead of always multiplying the state's emissions budget for the control period by a value of 21 percent, the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total historical heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. For example, if the total reported heat input of the state's covered sources for the 2025 control period is 130 percent of the historical heat input used in computing the state's 2025 budget, then the state's variability limit for the 2025 control period will be 30 percent of the state's emissions budget instead of 21 percent of the state's emissions budget. The EPA expects that the minimum 21 percent will apply in almost all instances, and that the alternative, higher percentage value will apply only in control periods where operational variability causes an unusually large increase relative to the historical data used in setting the state's emissions budget, which would be a situation meriting a temporarily higher variability limit and assurance level. The revised methodology for determining the variability limits will apply both with respect to control periods when a state's emissions budget is a preset budget established in this final rule and with respect to control periods when a state's emissions budget is a dynamically-determined budget computed using the procedures laid out in the regulations, and it will apply starting with the 2023 control period rather than starting with the 2025 control period as proposed.

The purpose of the revision to the variability limits is to better align the variability limits for successive control periods with the heat input data used in setting the state emissions budgets. Under the final rule, each dynamically

[319] 531 F.3d at 908.

[320] As discussed in section VI.B.8, the EPA is also establishing a new secondary emissions limitation for individual units that will apply in situations where an exceedance of the relevant state's assurance level has occurred.

[321] *See* 40 CFR 97.1002 (definitions of "common designated representative," "common designated representative's assurance level" and "common designated representative's share"), 97.1006(c)(2), and 97.1025.

determined emissions budget will be computed using the latest available reported heat input, which for each budget set for a control period in 2026 or a later year will be the average state-level heat input for the control periods two, three, and four years before the control period whose budget is being determined (for example, the dynamic state emissions budgets for the 2026 control period will be computed in early 2025 using the reported state-level heat input for the 2022–2024 control periods). The revised variability limits will be well coordinated with the budgets established using this dynamic budgeting process, because the percentage change in the actual heat input for the control period relative to the earlier multi-year average heat input used in computing the state's emissions budget will be an appropriate measure of the degree of operational variability actually experienced by the state's EGUs in the control period relative to the assumed operating conditions reflected in the state's budget. Setting a variability limit in this manner is thus entirely consistent with the overall purpose of including variability limits in the assurance provisions.

As discussed in sections VI.B.1.b.i and VI.B.4, for the 2023–2025 control periods the state emissions budget for a given control period will be the preset budget determined in this rule, and for the 2026–2029 control periods, the state emissions budget for a given control period will be the preset budget determined in this rule rather than the dynamically determined budget computed in the year before the control period unless the dynamic budget is higher than the preset budget. If the state emissions budget is the preset budget, the historical heat input data reflected in that budget will be the heat input data for the 2021 control period, adjusted to reflect projected changes in fleet composition over time that are known at the time of this rulemaking, but not adjusted to reflect changes in fleet composition that are not known at the time of the rulemaking or changes in the utilization of individual units.[322] In this case, the variability limit for the control period would be the higher of 21 percent or the percentage change in the actual heat input for the control period relative to the heat input for the 2021 control period as adjusted to reflect the projected changes in fleet composition. The EPA believes it is reasonable to apply the same principle in setting the variability limit in control periods where the preset floor budgets are used as in control periods where the dynamically determined budgets are used, because the preset floor budgets are computed using the same principles as the dynamically determined budgets, with the major difference being that the available heat input data used in computing the preset budgets are necessarily less current. Accordingly, because preset budgets established in this manner are used starting with the 2023 control period, the EPA believes it is also reasonable to begin implementing the revised methodology for determining variability limits starting with the 2023 control period.

The reason the EPA is using the higher of a fixed 21 percent or the percentage change in heat input computed as just described is that the EPA believes that, for operational planning purposes, it can be useful for sources to know in advance of the control period a minimum value for what the variability limit could turn out to be. Because a state's actual total heat input for a control period is not known until after the end of the control period, this revision will have the consequence that the state's final variability limit and assurance level for the control period also will not be known until after the control period. However, because the rule provides that the variability limit will always be at least 21 percent, the sources in a state will be able to rely for planning purposes on the knowledge that the assurance level will always be at least 121 percent of the state's emissions budget for the control period. Advance knowledge of the minimum possible amount of the assurance level can be useful to sources, because one way a fleet owner can be confident that it will never incur the 3-for-1 allowance surrender ratio owed for emissions exceeding its state's assurance level is to plan its operations so as to never allow the emissions from its fleet to exceed the fleet's aggregated share of the state's assurance level for the control period. Knowing that the variability limit will always be at least 21 percent will provide sources with minimum values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the minimum variability limit. To determine appropriate variability limits for the trading programs established in CSAPR, the EPA analyzed historical state-level heat input variability over the period from 2000 through 2010 as a proxy for emissions variability, assuming constant emissions rates. *See* 76 FR 48265. Based on that analysis, the variability limits for ozone season NO_X in both CSAPR and the CSAPR Update were set at 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading programs were then codified in 40 CFR 97.510 and 97.810, along with the respective state budgets.[323] For the Revised CSAPR Update, the EPA performed an updated variability analysis for the twelve states being moved into the Group 3 trading program in that rulemaking, evaluating historical state-level heat input variability over the period from 2000 through 2019. The updated analysis again resulted in a variability estimate of 21 percent. The EPA also considered shorter time periods for the updated analysis and found that the resulting variability estimates were not especially sensitive to the particular time period analyzed.[324] A further updated analysis for this rulemaking again results in a variability estimate of 21 percent for most states, and although the historical analysis indicates a higher percentage for the covered state with the smallest total heat input figures in this analysis—New Jersey—the EPA does not consider it appropriate to raise the minimum variability limit percentage beyond 21 percent for all other covered states based on the analytic results for one state, where small absolute heat input figures have resulted in a larger variability percentage.[325] (Moreover, because of the provision allowing a state's variability limit for a given control period to be higher than 21 percent if the state's actual heat input exceeds the heat input used to set the state's emissions budget by more than 21 percent, there is no need to set a minimum variability limit higher than 21 percent specifically for New Jersey.) Based on the consistent conclusions of these multiple analyses, the EPA is continuing to use 21 percent as the

[322] The total heat input amount used in computing each state's preset emissions budget for each control period from 2023 through 2029 is included in Appendix A of the Ozone Transport Policy Analysis Final Rule TSD at column I of the "State 2023"–"State 2029" worksheets.

[323] Briefly, the 21 percent variability limit was determined in the analysis by identifying, for all the states in the region covered by the ozone season NO_X trading program, and at a 95 percent confidence level, the maximum expected deviation in any state's total heat input for any single control period in the data sample from that state's trend-adjusted mean total heat input for all the control periods in the data sample. For details on the original variability analysis for 26 states over the 2000–2010 period, including a description of the methodology, see the Power Sector Variability Final Rule TSD from the CSAPR (EPA–HQ–OAR–2009–0491–4454), available in the docket for this rule.

[324] For the updated variability analysis for twelve states for the 2000–2019 period, *see* the Excel file "Historical Variability in Heat Input 2000 to 2019.xls", available in the docket for this rule.

[325] *See* the Excel document, "OS Heat Input—Variability 2000 to 2021.xls" for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

minimum value in the revised approach for establishing variability limits for all control periods under this rule.

The provisions of the final rule relating to assurance levels and variability limits are unchanged from proposal, with the exception that the provision establishing a higher variability limit for a state in a given control period where the state's actual heat input exceeds the heat input used in computing the state emissions budget for that control period by more than 21 percent will be implemented starting with the 2023 control period instead of the 2025 control period.

Comment: Some commenters supported the EPA's proposal to raise a state's variability limit above 21 percent for a given control period if the state's actual heat input for the control period was more than 121 percent of the historical heat input used to set the state's budget for that control period. These commenters agreed with the EPA that making this adjustment is consistent with the assurance provisions' purpose of strongly incentivizing each state to achieve its required emissions reductions within the state while also accounting for year-to-year variability in electric system operations.

One commenter stated that the EPA should not finalize the proposed revision to the variability limit provisions, claiming that by allowing sources in some states to increase utilization and heat input so as to exceed the state's budget by more than 21 percent in a given year, the adjustment would then cause the state's subsequent dynamically determined budgets to be higher, allowing greater emissions over time.

Response: The EPA disagrees with the comment advocating against finalization of the proposed change to the variability limit provisions. The Agency continues to view the proposed change as useful for accommodating instances where, because of electrical system operating needs, a state's actual total heat input in a control period exceeds the historical heat input used to set the state emissions budget for the control period, potentially causing increased emissions even when all EGUs in a state are achieving emissions rates consistent with the Step 3 emissions control stringency. Moreover, the EPA does not believe that the provision would lead to higher overall program-wide budgets. No extra allowances would be created by the increase in a state's variability limit, so with or without the adjustment, any allowances to cover the emissions in excess of the state's budget would still need to be obtained through acquisition of allowances issued to sources in other states or the use of banked allowances. Thus, to the extent that the change in the variability limit provisions facilitates shifting of generation from some states to other states, increased heat input in the first set of states would generally be offset by decreased heat input in the second set of states, such that any increases in future dynamic budgets for the first set of states would be offset by decreases in future dynamic budgets for the second set of states. In addition, the final rule's use of multiple years of historical heat input data to compute the dynamically-determined state budgets will moderate the effect of any single year's heat input on the dynamically-determined budgets for future control periods.

6. Annual Recalibration of Allowance Bank

As discussed in section VI.B.1.b of this document, the EPA is making two revisions to the Group 3 trading program designed to better maintain the Step 3 emissions control stringency over time. The first proposed revision, discussed in section VI.B.4 of this document, is to adopt a dynamic budget-setting methodology that will allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, revision is to recalibrate the bank of unused allowances each control period to prevent allowance surpluses from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the Step 3 emissions control stringency.

As proposed and now finalized in this rule, the bank recalibration process will start with the 2024 control period, after the compliance process for the 2023 control period for all current and newly added states in the Group 3 trading program has been completed. The recalibration process for each control period will be carried out on or shortly after August 1 of that control period, two months after the compliance deadline for the previous control period, making the date of the first recalibration August 1, 2024. The recalibrations take place on August 1 each year because compliance for the previous control period would not be completed until after June 1. However, because data on the amounts of allowances held are publicly available and the total quantity of allowances needed for compliance for the previous control period will be known shortly after the end of that control period, sources and other market participants will be able to ascertain with reasonable accuracy shortly after the end of each control period what degree of recalibration to expect for the next control period, even if the recalibration would not actually be carried out until the following August. The EPA will make an estimate of the applicable calibration ratio for each control period publicly available no later than March 1 of the year of the control period for which the bank will be recalibrated.

Before undertaking a recalibration process each control period, the EPA will first determine whether the total amount of all banked Group 3 allowances from previous control periods held in all facility accounts and general accounts in the Allowance Management System exceeds the target bank amount. (For this purpose, no distinction will be made between banked Group 3 allowances issued from the state emissions budgets for previous control periods and banked Group 3 allowances issued through the conversion of previously banked Group 2 allowances.) If the total amount of banked Group 3 allowances does not exceed the target bank amount, the EPA will not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA will determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the account's total holdings of banked Group 3 allowances immediately before the recalibration multiplied by the target bank amount and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA will deduct from each account any banked Group 3 allowances exceeding the account's recalibrated amount of banked allowances.

As the target bank amount used in the recalibration process for each control period, the EPA will use an amount determined as a percentage of the sum of the state emissions budgets for the control period. For the control periods from 2024 through 2029, the target percentage will be 21 percent, which is the sum of the states' minimum variability limits.[326] For control periods in 2030 and later years, the target percentage will be 10.5 percent, or half of the sum of the states' minimum

[326] As discussed in section VI.B.5, an individual state's variability limit can be higher than 21 percent in a given control period if the state's actual heat input for that control period is more than 121 percent of the historical heat input used in computing the state emissions budget for the control period.

variability limits. In the proposal, the EPA cited two reasons for proposing the 10.5 percentage amount. First, in the transition from CSAPR to the CSAPR Update, where the EPA set a target bank amount 1.5 times the sum of the variability limits, and in the transition from the CSAPR Update to the Revised CSAPR Update, where the EPA set a target bank amount of 1.0 times the sum of the variability limits, in each case the initial bank proved larger than necessary, as total emissions of all sources in the program were less than the budgets. Second, an analysis of year-to-year variability of heat input for the region covered by this rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95 percent confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the minimum variability limit of 21 percent for the states in the trading program.[327] When the analysis is performed at the regional level, the data show less year-to-year variation than when the analysis is performed at the individual state level. Within the trading program structure, it is reasonable to use variability analyzed at the level of individual states to set the variability limits, which apply at the level of individual states, while using variability analyzed at the level of the overall region to set a target level for a bank, which will apply at the level of the overall program.

In the final rule, in response to comments, the EPA has determined to maintain the 10.5 target percentage for the reasons discussed in previous paragraphs, but to defer application of this target percentage until the 2030 control period. For the control periods from 2024 through 2029, the EPA will instead use a target percentage of 21 percent. The reason for using a higher target percentage for the 2024–2029 control periods is to provide additional support for allowance market liquidity during these years, which both the EPA and commenters view as an important period of generating fleet transition for the power industry.

The annual bank recalibrations, at either ratio, are an important enhancement to the trading program that will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS over time. Moreover, the recalibrations are less complex than alternative approaches would be. For example, the NO_X Budget Trading Program established in the NO_X SIP Call also contained provisions designed to prevent excessive accumulations of banked allowances on program stringency, but those provisions—under the name ''progressive flow control''—introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions or less than one ton of emissions in the current control period. As a consequence of this uncertainty, in some control periods, allowances banked from earlier control periods traded at lower prices than allowances issued for the current control period.[328] The EPA considers the recalibration mechanism established in this rule to be simpler with less associated uncertainty. Following each bank recalibration, all allowances usable for compliance in the control period will have known, equal compliance values for the remainder of the control period and until the deadline for surrendering allowances after the control period.

Finally, the EPA observes that the recalibration mechanism is entirely consistent with the Agency's existing authority under 40 CFR 97.1006(c)(6) to ''terminate or limit the use and duration'' of any Group 3 allowance ''to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' The Administrator is determining that the recalibrations are both necessary and appropriate to ensure that the control stringency selected in this rulemaking is maintained and states' good neighbor obligations with respect to the 2015 ozone NAAQS are addressed. The recalibration process will complement the revised budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods. For further discussion of the reasons for bank recalibration, see section VI.B.1.b.ii of this document.

The bank recalibration mechanism finalized in this rule is unchanged from the proposal except for the final rule's adoption of a target percentage of 21 percent rather than 10.5 percent for the control periods from 2024 through 2029. The EPA's responses to comments on the bank recalibration mechanism are discussed in the remainder or this section and in section 5 of the *RTC* document. Further discussion of the reasons for adopting a higher target percentage for the 2024–2029 control periods is included in section VI.B.1.d of this document.

Comment: Some commenters acknowledged the EPA's authority to manage the quantities of allowances carried over from one control period to the next as banked allowances, including some commenters who as a policy matter did not support such an approach. Other commenters claimed that any removal from the program of allowances banked in earlier control periods would constitute an unlawful taking of property or would constitute unlawful overcontrol.

Response: The EPA disagrees with comments contending that the proposed bank recalibration provisions would be unlawful, either as asserted takings of property or as over-control for purposes of the Good Neighbor provision. With respect to the claim that removing allowances would constitute takings of property, the commenters misconstrue the nature of an allowance. The allowances used in the Group 3 trading program are created under the program's regulations, which expressly provide that the allowances are not property rights but are limited authorizations to emit NO_X in accordance with the provisions of the Group 3 trading program.[329] These provisions of the Group 3 trading program regulations have been in existence since the Revised CSAPR Update and were not reopened in this action. This approach of creating limited authorizations to engage in particular forms of conduct within a regulatory program extends back to the Acid Rain Program, where the approach was mandated by Congress, and has been followed by EPA in each subsequent allowance trading program for the electric power sector.[330] Moreover, as noted earlier in this section, the Group 3 trading program regulations provide the EPA

[327] See the Power Sector Variability Final Rule TSD from CSAPR, available at *https://www.epa.gov/csapr/power-sector-variability-final-rule-tsd* for a description of the methodology. Also see the Excel document ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

[328] For more discussion of the progressive flow control mechanism, as well as allowance price data showing a discounted value for banked allowances, see ''NO_X Budget Trading Program: 2005 Program Compliance and Environmental Results'' (September 2006) at 28–30, *https://www.epa.gov/sites/default/files/2015-08/documents/2005-nbp-compliance-report.pdf*.

[329] 40 CFR 97.1006(c)(6)–(7).

[330] *See, e.g.,* 42 U.S.C. 7651b(f) and 40 CFR 72.9(c)(6)–(7) (Acid Rain Program example); 40 CFR 97.6(c)(6)–(7) (Federal NO_X Budget Trading Program example); 40 CFR 97.106(c)(5)–(6) (CAIR NO_X Annual Trading Program example).

Administrator with the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act, and the Administrator is making such a determination in this rule.

The EPA also disagrees that bank recalibration would constitute overcontrol. The emissions that are permissible in a given control period consistent with the Step 3 control stringency are quantified in the state emissions budgets for the control period. Banked allowances from previous control periods are necessarily surplus to the state emissions budgets for the current control period. As noted in section VI.B.1, in an allowance trading program, banking provisions can serve several useful purposes, including continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. However, these useful purposes do *not* include allowing sources to plan to emit in excess of the Step 3 control stringency as represented by the state emissions budgets for the control period. Accordingly, in the overcontrol analysis discussed in section V.D.4, the EPA analyzed whether the emissions reductions necessary to meet the state emissions budgets without relying for compliance purposes on any allowances banked in earlier control periods would result in overcontrol and determined there would be no overcontrol. (That is, the modeling of the effects of the Group 3 emissions budgets in 2026 did not include an assumption that there would be any banked allowances.) Thus, even if the Agency had finalized regulatory provisions removing *all* banked allowances from the trading program between control periods—in contrast to the actual bank recalibration provisions, which permit substantial quantities of banked allowances to remain in the trading program—the information available to the Agency suggests such provisions would not constitute over-control. With respect to some commenters' assertions that bank recalibration would over-control by ''writing off'' emission reductions that may have gone beyond the reductions necessary to address the Good Neighbor provision or would make it more difficult to create surplus allowances in one control period to offset excess emissions in later control periods, EPA notes that the NAAQS apply continuously, and the possibility that the sources in a state may have done more than the minimum necessary to meet the state's Good Neighbor obligations in one control period does not create a right for the state to do less than is necessary to meet the state's Good Neighbor obligations in subsequent control periods.

Comment: Some commenters expressed concern that excessive quantities of banked allowances, like excessive quantities of budgeted allowances, can lead to lower allowance prices. The commenters observed that with lower allowance prices, some units would likely operate their controls less effectively, resulting in a greater likelihood that the emissions stringency found necessary in this rule would not be sustained. Other commenters expressed the view that other provisions of the rule, including more stringent state emissions budgets, the backstop daily NO_X emissions rate provisions, and the assurance provisions would be sufficient to incentivize EGUs to operate their controls effectively, making allowance bank recalibration superfluous for this purpose.

Response: The EPA agrees with the comments explaining that without bank recalibration, the quantities of banked allowances can grow, leading to lower allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency, and disagrees with the comments arguing that other rule provisions would make bank recalibration unnecessary. The suggestion that the assurance provisions can maintain program stringency regardless of allowance quantities ignores the fact that the emission levels consistent with the Group 3 control stringency in a given control period are the state emissions budgets, not the higher assurance levels. If the quantities of banked allowances in the program grow to the point where sources collectively can plan to emit above the collective state emissions budgets, then the trading program would be unable to ensure that the Group 3 control stringency is being achieved, even if emissions do not rise further than the assurance levels. Further, there are now examples from the Group 2 trading program of sources emitting in excess of the state-wide assurance levels, because a glut of banked allowances which was not prevented by the regulations for that trading program rendered even the three-to-one surrender ratio ineffective. Suggestions that the backstop emissions rate provisions can maintain program stringency regardless of the quantities of banked allowances are similarly mistaken, because rather than reducing overall emissions of all sources in the trading program, the backstop rate provisions are designed to ensure that the largest individual sources of potential emissions operate their controls consistently. If the quantities of banked allowances are allowed to grow to the point where sources collectively can plan to emit above the collective state emissions budgets, the backstop rate provisions would do nothing to constrain emissions from the sources not subject to the backstop rate.

With respect to the suggestion that state emissions budgets reflecting sufficient control stringency can avoid the need for bank recalibration, the EPA observes that the budget-setting and bank recalibration provisions in this rule are complements, not substitutes. If in a given year sources collectively emit against the collective state emissions budgets such that the ending allowance bank—that is, the allowances remaining after deduction of the allowances required for compliance—is less than the bank target amount, then the bank will not be recalibrated for the following control period. However, in the event that sources collectively emit against the collective state emissions budgets such that the ending allowance bank is above the bank target amount, then the recalibration provisions will ensure that the recalibrated allowance bank does not introduce an excessive overall quantity of allowances into the trading program for the following control period when combined with the state emissions budgets calculated for that control period. Without the recalibration provisions, the trading program would lack any mechanism for removing excess allowances that are inconsistent with maintaining the Step 3 emissions control stringency which the Step 4 trading program is designed to implement.

Comment: Some commenters claimed that the recalibration process itself would have undesirable consequences. First, some said that because bank recalibration would be executed partway through the control period, it would introduce uncertainty concerning the quantities of allowances each source would have available, impeding efforts to plan. Second, some commenters claimed that the prospect of bank recalibration would create counterproductive incentives for allowance holders. According to the commenters, allowances holders would be incentivized to ''use or lose'' their allowances (to reduce the number of allowances that would be removed from their accounts in the recalibration process), thereby causing increased emissions, or alternatively would be incentivized to refuse to sell allowances (to allow the holders to have more allowances after the next recalibration), thereby reducing allowance market liquidity.

Response: The EPA disagrees with these comments. As discussed previously in this section, the recalibration process has been scheduled for August 1 of each control period because compliance for the previous control period (and the associated allowance trading activities) would not be completed until after June 1. However, the information needed to project the degree of recalibration will be available by early November of the previous year, and the EPA will make an estimate publicly available no later than March 1, two months before the start of the control period. Further, at least 80 percent of the allowances for use in a given control period will be the allowances allocated from the state emissions budgets (with the recalibrated banked allowances from the prior control period comprising the remainder), and the emissions budgets and unit-level allocations amounts will be known approximately a year before the start of the control period.

The comments claiming that the introduction of a bank recalibration process would create incentives to "use or lose" allowances or to hoard allowances are not persuasive. By reducing the supply of allowances carried over from previous control periods, bank recalibration would tend to raise the price of allowances in the current control period, making it more cost-effective and therefore in sources' interest to further reduce their emissions than to increase their emissions. Higher allowance prices would also increase the cost of hoarding allowances just as higher fuel prices raise the cost of maintaining large fuel inventories. Moreover, the EPA expects that the prospect of having banked allowances recalibrated after the end of the control period is much more likely to *discourage* hoarding than to encourage it. Given the choice between holding an allowance which may be removed as part of an upcoming recalibration process or instead selling the allowance for cash, the sale option will become more attractive. By creating a "sell or lose" incentive for holders of surplus allowances, the recalibration process should increase allowance market liquidity. At the same time, by ensuring a banked allowance will always have some value for use in a future control period, the bank recalibration mechanism in this program will continue to incentivize early emissions reductions.

Comment: Turning to the level of the bank recalibration target, some commenters objected to the target bank percentage of 10.5 percent, saying that a larger bank would be needed to ensure that sufficient allowances would be available to enable sources to run as needed to provide reliable electricity service, particularly with the large year-to-year swings in budgets that the commenters anticipated could occur with dynamic budgets computed using a single rolling historical year and with anticipated growth in renewable generation. Some commenters recommended a target bank percentage of 21 percent. Some commenters stated that even if the overall quantity of allowances available for use was greater than the total amount of emissions, a larger bank of allowances would facilitate trading and promote greater allowance market liquidity, citing reports of high allowance prices in 2022.

Response: As discussed in sections VI.B.1.d and VI.B.4 and earlier in this section, the EPA does not agree with comments suggesting that annual bank recalibration in itself poses a risk to electric grid reliability. Nevertheless, the Agency has made several changes from proposal in the final rule designed to address concerns expressed about reliability by increasing compliance flexibility through the 2029 control period. These changes through the 2029 control period include the use of a target bank percentage of 21 percent and the promulgation of preset budgets that will serve as the state emissions budgets unless the dynamic budgets for the control periods are higher. In addition, to reduce year-to-year variability under the budget-setting methodology, dynamic budgets will be calculated using multiple years of historical heat input data instead of heat input data from a single year. The EPA views these changes as responsive to the principal reasons that commenters gave for their claims that the target bank percentage should be higher than 10.5 percent. Regarding the claim that a higher target bank percentage is needed because increased renewable generation makes the demand for fossil generation more variable, commenters did not provide evidence demonstrating that the overall quantities of fossil generation throughout the multi-state region covered by this rule—as opposed to the operating patterns of some individual units—are becoming more variable, and the Agency declines to make an adjustment for such a reason at this time.

With respect to the comments advocating for an even higher bank target percentage to facilitate trading and promote market liquidity, the Agency observes that any such advantage of larger allowance banks must be balanced with the disadvantages of excess allowance supply—specifically, reduced allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency. In the final rule, the EPA finds that a reasonable balance between these opposing considerations is struck by temporarily adopting a higher bank target percentage of 21 percent (consistent with the initial bank targets used in this rule and previous rules) and deferring implementation of the 10.5 percent target bank percentage identified by the Agency's analysis as a sustainable percentage in the longer term until the 2030 control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in section V of this document (*i.e.,* the Step 3 emissions control stringency) are incentivized and secured primarily through the corresponding seasonal state emissions budgets (expressed as a seasonal tonnage limit for all covered EGUs within a state's borders) described earlier, the EPA is also incorporating a backstop daily emissions rate of 0.14 lb/mmBtu applied to coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states, except circulating fluidized bed units. This is important for ensuring the elimination of significant contribution on a more consistent basis from the relevant sources and over each day of the ozone season.

Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls (except circulating fluidized bed units) starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. See Appendix A of the Ozone Transport Policy Analysis Final Rule

TSD for a list of coal-fired steam units serving generators larger than or equal to 100 MW in covered states for which the identified backstop emissions rate will apply.

For each unit subject to the backstop daily emissions rate provisions for a given control period, the amount of emissions subject to the 3-for-1 surrender ratio will be determined as follows, generally on an automated basis using the unit's data acquisition and handling system (DAHS) required under 40 CFR part 75. For each day of the control period where the unit's average emissions rate for that day was higher than 0.14 lb/mmBtu, the owner or operator will compute what the unit's reported emissions on that day would have been (given the unit's reported heat input for the day) at an emissions rate of 0.14 lb/mmBtu. The difference between the unit's emissions for the day as actually reported and the emissions that would have been reported if the unit's emissions rate was 0.14 lb/mmBtu is the unit's daily exceedance. The amount of emissions subject to the 3-for-1 surrender ratio for the control period is the sum of the unit's daily exceedances for all days of the control period minus 50 tons (but not less than zero).[331] All calculations will rely on the data monitored and reported for the unit in accordance with 40 CFR part 75.

The EGU NO_X Mitigation Strategies Final Rule TSD describes the methodology for deriving the 0.14 lb/mmBtu daily rate limit in more detail. The methodology is summarized as follows. First, consistent with stakeholders' focus on providing daily assurance of control operation, which is consistent with the 8-hour form of the 2015 ozone NAAQS and the tendency for ozone levels to spike on a diurnal cycle, the EPA determined that daily (as opposed to hourly or monthly) was an appropriate time metric for backstop emissions rate limits instituted to ensure operation of controls on high ozone days. The EPA derived the 0.14 lb/mmBtu daily rate limit by determining the particular level of a daily rate that would be comparable in stringency to the 0.08 lb/mmBtu seasonal emissions rate that the Agency has identified as reflecting SCR optimization at existing units.[332] The EPA first conducted an empirical exercise using reported daily emissions rate data from existing, SCR-controlled coal units that were emitting at or below 0.08 lb/mmBtu on a seasonal average basis. This seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions. When the EPA examined the daily emissions rate pattern for these units considered to be optimizing their SCRs on a seasonal basis, the EPA observed that over 95 percent of the time, their daily rates were below 0.14 lb/mmBtu. In addition, for these units, less than 1 percent of their seasonal emissions would exceed this daily rate limit.

The EPA conducted this analysis to be consistent with the methodology developed in the 2014 1-hr SO_2 attainment area guidance for identifying "comparably stringent" emissions rates over varying time-periods.[333] Appendix C of that guidance describes a series of steps that involve: (1) compiling emissions data to reflect a distribution of emissions rates with various averaging times, (2) determining the 99th percentile of the average emissions values compiled in the previous step, and then (3) applying "adjustment factors" or ratios of the 99th percentile values to emissions rates to convert them (usually from a short-term rate to a longer-term rate). In this case, the EPA applied the methodology in reverse to convert a longer-term limit (the seasonal rate of 0.08 lb/mmBtu which was assumed to be equivalent to a 30-day rate of 0.08 lb/mmBtu for purposes of this comparison of rates across averaging times) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu).

The inclusion of a 50-ton threshold for emissions exceeding the backstop daily emissions rate before the 3-for-1 surrender applies is a change from the proposal. As discussed in section VI.B.1.d of this document, the EPA made this change in response to comments concerning the possibility that the 3-for-1 surrender ratio could otherwise have applied to emissions outside an EGU operator's control, with the most important example being the emissions during unit startup before SCR equipment can be brought into service, and to a lesser extent the emissions during unit shutdown. The analysis used by the EPA to derive the 50-ton threshold is described in detail in the Ozone Transport Policy Analysis Final Rule TSD. Briefly, for a set of 164 SCR-equipped units with seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu in 2021, the EPA evaluated the total amounts of emissions that would have been determined to exceed a daily average emissions rate of 0.14 lb/mmBtu in the 2021 and 2022 ozone seasons. In the 2021 ozone season, only 572 tons out of these units' total emissions of 60,350 tons, or 0.9 percent, would have been considered exceedances, with an average exceedance per unit of less than 4 tons. The highest amount for any of the 164 individual units in either ozone season was 48 tons. Based on this analysis, the EPA concludes that adding a 50-ton threshold to the backstop daily emissions rate provisions will ensure that substantially all emissions outside the control of an SCR-equipped unit's operator will not be subject to the 3-for-1 surrender ratio. Because there is no reason to expect the range of emissions during conditions when SCR controls cannot be operated to differ between SCR-equipped units and units without SCR, inclusion of the 50-ton threshold effectively prevents application of the 3-for-1 ratio to emissions during startup and shutdown by units without SCR as well.

At the same time, the EPA believes the 50-ton threshold is not large enough to eliminate the intended incentive to achieve emissions rates consistent with good SCR performance under conditions other than startup and shutdown. For a set of 124 SCR-equipped units with seasonal average NO_X emissions rates above 0.08 lb/mmBtu, the total amount of emissions exceeding a daily average emissions rate of 0.14 lb/mmBtu in the 2021 ozone season was 18,629 tons. Of this total amount, 15,374 tons would have been in excess of the 50-ton thresholds for the various units, indicating that even after application of the threshold, the 3-for-1 surrender ratio would have applied to over 80 percent of the daily exceedance amounts.

The backstop daily NO_X emissions rate provisions finalized in this rule are unchanged from the proposal except for the inclusion of a 50-ton threshold for emissions exceeding the backstop emissions rate before the 3-for-1 surrender ratio applies and the deferral of the application of the provisions to units without existing SCR controls

[331] In the regulatory text at 40 CFR 97.1024 defining the total quantity of allowances that must be surrendered for a source's emissions in a control period, these amounts of emissions for all the units at the source are subject to a requirement to surrender two extra allowances per ton in addition to the usual 1-for-1 allowance surrender requirement, yielding a total surrender ratio of 3-for-1 for emissions over the 50-ton threshold.

[332] *See* page 24 of "Guidance for 1-hour SO_2 Nonattainment Area SIP Submission" at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* "A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level 1 since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis."

[333] *See* Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions available at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.*

until the 2030 control period or, if earlier, the second control period in which new SCR controls are operated at a unit. The EPA's responses to comments on the backstop daily NO_X emissions rate provisions, including the reasons for these changes, are discussed in the remainder of this section and in section 5 of the *RTC* document.

Comment: Some commenters strongly supported the backstop daily emissions rate provisions, noting their benefit to downwind receptors on potential nonattainment days, their benefit to neighboring communities, and evidence of deterioration in SCR performance in the absence of such provisions. Other commenters stated that the backstop daily emissions rate provisions are unnecessary, either because SCR-equipped EGUs would already be sufficiently incentivized to operate and optimize their controls by the stringency of the state emissions budgets and the resulting allowance prices or because most SCR-equipped EGUs are already required to operate and optimize their SCRs by conditions in their operating permits. Some commenters cited previous EPA analyses showing that it is unusual for SCR-equipped units to turn off their SCRs only on high electricity demand days (HEDD).

Commenters suggested diverse possible changes to the types of EGUs that would be covered by the backstop daily emissions rate provisions. Some commenters stated that the provisions should apply to all EGUs or to all SCR-equipped EGUs, including non-coal-fired units. Other commenters stated that exemptions should be provided for units operating at capacity factors below 10 percent or for emissions during emergencies.

Some commenters stated that implementation of the backstop daily emissions rate provisions would cause unintended and counterproductive consequences. Some of these commenters claimed that by requiring the surrender of extra allowances, the backstop emissions rate provisions would create shortages of allowances for the program overall. Other commenters claimed that the disincentives to operate units subject to the backstop emissions rate provisions would cause load to shift to higher-emitting generators not covered by the trading program (such as sources in states outside the program's geographic region, EGUs smaller than 25 MW, and sources considered demand-side resources, including end-user-sited diesel generator units), potentially resulting in higher overall emissions.

Response: The EPA agrees that backstop daily emissions rate provisions should be implemented and disagrees with comments suggesting that the need for the backstop daily emissions rate provisions is contradicted by previous EPA analyses or is already adequately addressed by other provisions of this rule or other legal requirements. As discussed in sections V.D.1 and VI.B.1.c of this document, the EPA has determined that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate. There are several important differences between this rule and previous actions addressing interstate ozone transport where the Agency did not include such provisions. First, this rule constitutes a full remedy, unlike some prior actions. Second, this rule is the first rule in which the EPA is addressing good neighbor obligations with respect to the more protective 2015 ozone NAAQS. Third, the EPA has examined the most recent data over a broader geographic and temporal footprint specific to the coverage of this rule, and it illustrates a greater degree of SCR performance erosion than in the prior years in which EPA conducted such analysis. Fourth, nonattainment and maintenance for this NAAQS are projected to persist well into the future in EPA's baseline, making enhancements and safeguards such as the backstop daily emissions rate provisions essential for securing elimination of significant contribution in future periods for which fleet configuration is inherently more uncertain.

With respect to claims that inclusion of the backstop daily emissions rate provisions is contradicted by the EPA's earlier analyses concerning SCR operational changes specific to high electricity demand days, the EPA disagrees. Historical data reported to the EPA show that multiple SCR-equipped units across the states covered by this action have chosen not to operate their SCRs, or to operate them at materially less than their full removal capability, for entire ozone seasons. The apparent infrequency of one type of behavior—*i.e.,* instances of units running their controls on most days but turning the controls off specifically on high electricity demand days—does not contradict the evidence concerning another type of behavior—*i.e.,* non-operation or suboptimal operation of controls for entire ozone seasons. The evidence from previous trading programs demonstrates that reliance solely on the incentives created by allowance prices and corresponding static state emissions budgets has been insufficient to cause all SCR-equipped units to operate and optimize their controls for entire ozone seasons.

The EPA acknowledges that some SCR-equipped units are likely already subject to other legal requirements calling for their SCR controls to be operated and optimized such that their seasonal average NO_X emissions rates will generally not exceed 0.08 lb/mmBtu (the level of seasonal SCR performance that the EPA used to derive the equivalent 0.14 lb/mmBtu level of daily SCR performance for the backstop daily NO_X emissions rate). However, commenters do not claim, and the EPA does not believe, that *all* SCR-equipped units are subject to other legal requirements calling for an equivalent degree of SCR operation and optimization. In the context of a multi-state trading program, it is more efficient and equitable, and far more transparent, for the EPA to establish rule provisions uniformly incentivizing all large coal-fired EGUs to install and operate SCR controls than to attempt to establish differentiated requirements for various units according to the EPA's analysis of the effectiveness of their pre-existing permit conditions. Further, to the extent that a given unit's permits already require SCR performance that would meet the backstop emissions rate established in this rule, or to the extent that allowance prices would incentivize the unit to operate the SCR anyway, the EPA expects that the backstop daily emissions rate provisions (as finalized with a 50-ton threshold to address emissions outside an EGU's control before the 3-for-1 surrender ratio applies) will cause no incremental cost for the unit.

The EPA disagrees with the suggested changes to applicability of the backstop emissions rate provisions. With respect to the comments advocating broader coverage, the EPA discusses its reasons for applying the provisions only to coal-fired EGUs in section VI.B.1.c of this document, including the fact that operation of SCR controls is a well-established practice among the best performing coal-fired boilers but not for non-coal-fired units.[334] The comments indicate a preference for a less flexible trading program design than the EPA has found appropriate but do not demonstrate that EPA's decision to allow greater flexibility is either impermissible or unreasonable; our reasoning in this regard is further explained in section VI.B.1.c.i of this

[334] Nationwide and among operating units in 2021, EPA identified the best performing quartile (*i e.,* lowest ozone season emissions rate) of coal-fired EGU boilers (excluding CFB units). Nearly 100 percent of these units (159 of 160 units) were equipped with SCR controls.

document. With respect to the comments advocating narrower coverage, the commenters have provided no information indicating that the sources for which exemptions are sought could not comply with the provisions, including through the surrender of additional allowances if necessary. The EPA notes that emissions from coal-fired units operating at low capacity factors may be concentrated around days of high electricity demand when incentives to minimize such emissions may be most helpful in mitigating downwind air quality problems. The EPA also notes that to the extent the comments are intended to support exemptions for units without existing SCR controls, the final rule defers application of the backstop emissions rate provisions to such units until the 2030 control period, providing additional flexibility to develop alternatives to the use of such units if the owners choose not to equip them with SCR controls.

Finally, the EPA also disagrees with the comments asserting that the backstop emissions rate provisions would cause unintended and counterproductive consequences. With respect to units already equipped with SCR controls, the EPA expects that by far the most important effect of the provisions will be to incentivize the units to operate and optimize their controls. The EPA sees no basis for speculation that such units would choose to operate in a manner that would result in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio or in generation being shifted to sources outside the trading program. The results of the EPA's modeling of benefits and costs of the rule show little leakage of emissions to non-covered sources, and commenters have presented no analysis to the contrary. For instance, as shown in Table 4.6 of the *RIA,* non-covered state ozone season NO_X emissions increased on average by 1 percent over the 2023–2030 time period between the base and final rule scenarios, while covered state emissions fell by 14 percent on average over the same period. With respect to units without existing SCR controls, the EPA expects the backstop emissions rate provisions, when they would take effect for such units, to provide a strong incentive against extensive operation (unless and until such controls are installed), again not resulting in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio.

Comment: For units with existing SCR controls, the aspect of the backstop daily emissions rate provisions that received the most attention in comments was how emissions outside the operator's control should be treated. Multiple commenters expressed concern that the backstop daily emissions rate would be exceeded on days when the SCR equipment cannot be operated for all or a portion of the day. The most commonly cited example of a situation where SCR equipment cannot be operated was unit startups, although some commenters also mentioned unit shutdowns, boiler or emissions control malfunctions, and unit maintenance or tests. The commenters expressed the view that emissions that cannot be controlled by SCR equipment should be exempted from the backstop emissions rate provisions and suggested a variety of approaches for implementing an exemption.

Some commenters also stated that the backstop emissions rate provisions would not sufficiently accommodate sustained low-load operation, such as where an SCR-equipped unit operates for extended periods at a load level too low to permit SCR operation so that the unit is ready to ramp up to higher load levels in less time than would be required for a startup. The commenters suggested that implementation of a backstop daily rate would reduce the ability to operate the units in this manner, generally reducing system flexibility. Some noted that the need for flexibility of this nature is increasing because of the rapid growth in intermittent renewable generation.

Additional comments on the backstop daily emissions rate provisions for units with existing SCR controls addressed the level of the daily emissions rate and the implementation timing. With respect to the rate level, various commenters suggested rates from 0.08 to 0.20 lb/mmBtu. With respect to implementation timing, some commenters stated that because immediate compliance was possible, the good neighbor provision required implementation as of the 2023 control period rather than the 2024 control period as proposed. Other commenters expressed the view that units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls. Some owners of SCR-equipped EGUs that exhaust to stacks shared with EGUs without SCR suggested that their particular units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls in order to avoid the cost of upgrading their emissions monitoring equipment.

Response: With respect to the topic of emissions outside an operator's control, as a general matter the EPA agrees that the backstop daily emissions rate provisions are intended to incentivize good SCR operation and that it was not the Agency's intent to apply a higher surrender ratio to emissions that are truly unavoidable, such as emissions occurring before an operator could reasonably initialize SCR operation when a unit is started up. As explained elsewhere in this section, the EPA selected the level of the backstop rate based on analysis of 2021 emissions data showing that for SCR-equipped coal-fired units achieving seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu, more than 99 percent of the units' emissions would fall below a backstop daily emissions rate of 0.14 lb/mmBtu. In response to the comments summarized previously, the EPA has further analyzed 2021 and 2022 emissions data to determine what if any modifications to the proposal might be appropriate to limit the imposition of a 3-to-1 allowance surrender requirement for emissions caused by circumstances outside an operator's control while preserving the intended incentive to operate and optimize SCR controls whenever possible. The analysis showed that for the same set of units achieving seasonal average emissions rates at or below 0.08 lb/mmBtu, the highest total amount of emissions exceeding the backstop daily emissions rate in either the 2021 or 2022 control period for any unit was 48 tons. The Agency views this amount as a reasonable upper bound on the quantity of emissions that might contribute to an exceedance of the backstop emissions rate arising from circumstances outside an operator's control for any coal-fired unit, not just the well-controlled units in the data set analyzed, because the amount generally encompasses all of a unit's emissions occurring in hours when an SCR could not be operated over an ozone season.

Based on this analysis, the backstop daily emissions rate provisions in this final rule exclude the first 50 tons of a unit's emissions in a given control period exceeding the backstop daily emissions rate from incremental allowance surrender requirements. The EPA finds that establishing a threshold of this nature will provide an appropriate maximum exclusion to all coal-fired units for unavoidable emissions caused by circumstances outside the operator's control while maintaining the incentives for less well-controlled units to improve their emissions performance on all days of the ozone season. Well-controlled units will likely have no emissions over the threshold that will be subject to incremental allowance surrender requirements, while for SCR-equipped units not already achieving a seasonal average emissions rates sufficiently low to routinely operate at daily average emissions rates of 0.14 lb/mmBtu or less, the incentive to reduce daily emissions rates will remain in place, because the 50-ton threshold is not expected to encompass all emissions exceeding the backstop daily emissions rate for such units. In contrast to more complicated exceptions suggested by commenters, the 50-ton threshold can be easily integrated into the overall trading program structure with minimal additional recordkeeping and reporting requirements.

With respect to the comments claiming that the inability of some SCR-equipped units to operate their SCR controls at sustained low load levels likewise merits alteration of the backstop daily emissions rate provisions, the EPA disagrees. There is no dispute concerning the technical need for a unit to attain and maintain a certain range of exhaust gas temperatures at the SCR inlet in order to achieve optimal SCR performance and no dispute concerning the general relationship between a unit's load level in a given hour and its ability to attain and maintain that exhaust gas temperature range in that hour. However, the EPA is also aware that at least in some cases, units whose role in the integrated electric system currently calls for them to operate at low load levels for sustained periods (such as overnight) in fact may be able to operate at slightly higher load levels that would accommodate SCR operation during those periods and still meet the needs of the integrated electric system, thereby avoiding operation of the unit for sustained periods with the SCR out of service. Figure B.5 in the EGU NO_X Mitigation Strategies Final Rule TSD illustrates this opportunity using data reported for the 2021 and 2022 ozone seasons by a large SCR-equipped EGU in Pennsylvania. In both ozone seasons, the unit often cycled daily between its maximum load of approximately 900 MW during the daytime and a lower load level overnight, and in both ozone seasons the unit's typical daytime emissions rate was between 0.05 and 0.07 lb/mmBtu. However, while in the 2021 ozone season, the unit cycled down to a load level of approximately 440 MW overnight and did not operate its SCR, in the 2022 ozone season, when allowance prices were considerably higher, the unit cycled down to a load level of approximately 540 MW overnight and did operate its SCR. Despite the higher nighttime generation levels, the result was a decrease of roughly 50 percent in the unit's seasonal average NO_X emissions rate, from approximately 0.14 lb/mmBtu to approximately 0.07 lb/mmBtu, and a comparable reduction in NO_X mass emissions. This unit is not uniquely situated; operating data for several other large SCR-equipped EGUs in Pennsylvania show the same past pattern of cycling down to low load levels at which the SCR controls cannot be operated, and these other units have similar opportunities to cycle down to somewhat higher load levels (necessarily subject to the needs and constraints of the integrated electric system) at which their SCR controls can be operated.[335] No commenter has submitted data to the contrary. Furthermore, this example demonstrates the need for this rule's backstop emissions rate provision, which (had it been in place) would have motivated this facility to operate its SCR overnight during the 2021 ozone season when the prevailing allowance price provided an insufficient incentive to do so.

The EPA disagrees with the comments advocating for a backstop daily emissions rate lower or higher than 0.14 lb/mmBtu. In general, these comments simply represent disagreements with the EPA's conclusions regarding the identification of required emissions reductions under this rule, as reflected in part by the EPA's conclusion that a seasonal average emissions rate of 0.08 lb/mmBtu reasonably reflects the seasonal average emissions rate achievable through optimization of controls by existing SCR-equipped units that are not already achieving a lower seasonal average emissions rate. Comments concerning the selection of the 0.08 lb/mmBtu seasonal average emissions rate are addressed in section V of this document. Commenters did not challenge the EPA's analysis identifying a daily emissions rate of 0.14 lb/mmBtu as comparable in stringency to a seasonal average emissions rate of 0.08 lb/mmBtu (see further discussion elsewhere in this section).

The EPA also disagrees with the comments stating that the backstop daily emissions rate provisions should apply to units with existing SCR controls starting in a control period earlier or later than the 2024 control period. The EPA does not consider implementation of the provisions in the 2023 control period feasible because it is currently unknown whether the necessary updates to the emissions recordkeeping and reporting software for all the affected sources could be completed and tested before July 30, 2023, which is the first quarterly reporting deadline for the 2023 control period. Moreover, as discussed in section VI.B.1.c.i of this document, implementing the requirements starting in 2024 will provide a window for EGUs to improve the consistency of SCR operation or in some cases to optionally install additional emissions monitoring equipment. As for the suggestion that implementation timing of the backstop daily emissions rate provisions for units with existing SCR controls should be synchronized with the later implementation timing for units without existing SCR controls, the EPA is not persuaded that there is any inequity in implementing provisions intended to incentivize operation of SCR controls first at sources that already have such controls and later at sources that do not already have such controls, allowing time for the latter sources to install the controls. In any event, in this instance, where some upwind sources have an immediate and highly cost-effective option for controlling their emissions, the statutory requirement for significant contribution to be eliminated as expeditiously as practicable so as to provide downwind states with the protection intended by the Good Neighbor provision overrides these sources' claim of inequity relative to sources whose emissions control options would take longer and have higher cost. We conclude that the backstop daily emissions rate is an important aspect of the elimination of significant contribution and should be applied at the relevant units. It is only out of recognition of unique circumstances associated with facilitating power-sector transition as identified by commenters, that we defer the application of the rate for the minority of units that have not yet installed SCR controls.

Finally, with respect to the SCR-equipped units that share common stacks with units that do not have SCR, the EPA disagrees that monitoring cost considerations merit a later implementation date for the backstop daily emissions rate provisions. As discussed in section VI.B.10 of this document, five plants with this configuration are covered by the rule (one of which has announced plans to retire in 2023). Under this rule, as proposed, the owner of a plant with this

[335] See the spreadsheet "Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data" in the docket.

configuration can choose between either upgrading the plant's monitoring systems so as to obtain unit-specific NO_X emissions rate data for each unit subject to the backstop daily emissions rate or else using the NO_X emissions rate data from the common stack, recognizing that the common stack emissions rate would generally be biased upwards relative to the emissions rate that could be reported for the SCR-equipped unit if that unit's emissions were monitored separately. Commenters have suggested a third option of a temporary exemption from the backstop emissions rate to avoid the cost of upgrading their monitoring systems. With the timing for implementation of the backstop emissions rate provisions for currently uncontrolled units in the proposal, the temporary exemption for the SCR-equipped units would have been in place for three control periods, from 2024 through 2026. With the final rule's deferral of the implementation of the backstop emissions rate provisions for the uncontrolled units for up to three years, the suggested temporary exemption for the SCR-equipped units would be in effect for up to six control periods, from 2024 through 2029. The EPA does not consider it reasonable to allow these SCR-equipped units an exemption from the backstop rate provisions for six years to avoid the cost of upgrading their monitoring systems, particularly given that the additional costs of monitoring at the individual-unit level are already borne by the large majority of other plants and the rule already provides these plants with an alternative to the monitoring system upgrades, if desired, by allowing the plants to use the emissions rate data from the common stack.[336]

Comment: With respect to units without existing SCRs, some commenters viewed the backstop daily emissions rate provisions as likely to make units without SCR altogether unwilling or unable to operate and characterized the provisions as a mandate for such units to install such controls or retire as of the control period when the provisions are implemented. Other commenters acknowledged that the provisions are not actually hard limits but stated that the higher allowance surrender ratio for emissions in excess of the backstop daily rate would nevertheless reduce the ability of such units to operate as needed to back up intermittent renewable generation. Some commenters claimed that inclusion of the backstop daily emissions rate provisions would substantially eliminate the potential benefits of allowance trading, because all units would have to meet the same emissions rate.

Some commenters stated that the proposed application of the daily backstop emissions rate provisions in the 2027 control period in some cases would occur only slightly before the units' otherwise planned retirement dates, and that short-term reliability considerations could create the need to make substantial investments in new controls at the units, which in turn could result in deferral of the units' retirement plans. In the proposal, the EPA requested comment on the possibility of deferring the application of the backstop emissions rate provisions to units without existing SCR controls until the 2029 control period if the owners provided the EPA with information indicating with sufficient certainty that the units would retire by the end of 2028. Commenters in favor of this concept suggested longer deferral periods, ranging from 2029 through 2032, and some also suggested that the EPA should simultaneously enlarge the emissions budgets to provide more allowances for units subject to the deferred requirement. Other commenters opposed any deferral of the applicability of the backstop rate provisions.

Response: The EPA disagrees that implementation of the backstop daily emissions rate provisions for EGUs without existing SCR controls constitutes a mandate for such units to install controls or retire but agrees that, as intended, the provisions would create strong incentives to minimize operation of the units unless and until controls are installed, and further agrees that in some instances retirement and replacement may be a more economically attractive option for the unit's customers and/or owners than installation of new controls. The EPA's rationale for determining at Step 3 that the control stringency required to address states' good neighbor obligations includes achievement of emissions rates consistent with good SCR performance at all large coal-fired EGUs (other than circulating fluidized bed boilers) is discussed in section V.D.1 of this document, and the EPA's rationale for determining at Step 4 that the trading program should include strong unit-level incentives to implement these controls is discussed in section VI.B.1.c. of this document. As noted in section VI.B.1.c of this document, the backstop daily emissions rate provisions are structured as incremental allowance surrender requirements rather than as directly enforceable emissions limits to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. The EPA appreciates that, in comparison to previous transport rules using a trading program mechanism for the power sector, the degree of flexibility available under this rule is reduced both by the greater stringency of the overall emissions reduction requirements, which leave less room to accommodate emissions from high-emitting units such as uncontrolled coal-fired units, and by the backstop daily emissions rate provisions. However, the EPA maintains that the trading program structure still is significantly more flexible than an array of directly enforceable emissions limits imposed on all EGUs or even on all coal-fired EGUs, and the comments do not show otherwise.

With respect to the comments concerning the timing for application of the backstop daily emissions rate provisions to EGUs without existing SCR controls, in the final rule the provisions will apply to these units starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. As discussed in section VI.B.1.d of this document, the purpose of this change from the proposal is to address concerns expressed by RTOs and other commenters that application of the backstop daily NO_X emissions rate to EGUs without existing SCR controls starting in the 2027 control period would provide insufficient time for planning and investments needed to facilitate the unit retirements they viewed as likely to be a preferred compliance pathway for some owners. The EPA recognizes that retrofitting new emissions controls on aging coal-fired EGUs may be less environmentally efficient than the alternative of retirement and replacement, which could yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have already been considering retirement in 2028 (or earlier) under compliance pathways available under the Clean Water Act effluent guidelines[337] and the coal combustion residuals rule under the

[336] The owner of one of the five plants with common stacks submitted comments stating that no location in the plant's ductwork could meet the criteria for a unit-specific monitoring location. As discussed in section VI.B.10 of this document, EPA staff have reviewed the comment and do not believe the commenter has provided sufficient information to reach such a conclusion.

[337] See 40 CFR 423.11(w).

Resource Conservation and Recovery Act.[338] The year 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas.[339] In addition, other regulatory actions at the state or Federal level are being or recently have been proposed. This includes among other things a proposed revision to the PM NAAQS for which transport SIPs would be due later in the 2020s. We understand that EGUs may wish to take the entire regulatory and market landscape into account when deciding whether to invest in SCR or pursue other NO_X reduction strategies. To facilitate a unit-level compliance alternative under this rule that maintains the NO_X reductions corresponding to SCR-level emissions control performance required by the state budgets from 2026 forward and that is potentially superior both economically and environmentally across multiple regulatory programs than installation of new, capital-intensive, post-combustion controls, the EPA is providing the fleet more flexibility in how to achieve those emissions reductions in the years through 2029. Relatedly, the deferral of the application of the backstop emissions rate provisions to uncontrolled units also addresses commenters' concerns that the provisions otherwise would reduce the ability of uncontrolled units to operate as needed to back up intermittent renewable generation (subject of course to the allowance-holding requirements to cover emissions). The deferral addresses this concern directly for the period through 2029, by eliminating application of the backstop provisions to uncontrolled EGUs through this period, and also indirectly after 2029, by ensuring the availability of sufficient time for owners and operators to complete other investments that may be needed to back up renewable generation after that point.

The EPA disagrees with the comments stating that application of the backstop daily emissions rate provisions to uncontrolled units should not be deferred and also disagrees with the comments stating that deferral should be accompanied by increases in the state emissions budgets reflecting higher assumed emissions rates for these units. The responses to these two comments are related. This rule complies with the mandate for the EPA to address good neighbor obligations as expeditiously as practicable and is based on a demonstration that emissions reductions commensurate with the overall emissions control strategy at Step 3 can be achieved beginning in the 2027 ozone season (following a two-year phase in of emissions reductions associated with installation of SCR retrofits). In the *RIA,* we demonstrate that EGUs will have multiple pathways to meeting the state budgets even if they choose not to install the SCR controls—thus no relaxation in the stringency of these budgets has been demonstrated to be warranted based on feasibility, necessity, or impossibility. The EGU economic modeling discussed in the *RIA* illustrates that many sources identified as currently having SCR retrofit potential elect not to install a SCR, and those that do retrofit SCR make no such installation until 2030. Yet, the fleet is able to comply with 2026 state emissions budgets (whose emissions reductions are premised in large part on assumed SCR retrofits) through reduced utilization (many of these units are projected to retire, and thus reduce emissions). While these changes in coal fleet utilization are not required or imposed through the EPA's state emissions budgets, they are projected to be an economic preference for a substantial portion of the unretrofitted fleet owing to future market and policy conditions. If sources do ultimately elect this pathway, then compliance will occur with significantly less demand on SCR retrofit labor and material markets than assumed at Step 3. The daily emissions rates are a backstop to the broader emissions reduction requirements, which we view as an important and necessary component to the elimination of significant contribution. But we also recognize that the objectives to be accomplished by the backstop must be balanced with larger economic and environmental conditions facing EGUs for which a deferral of the backstop rate ultimately is the most reasonable approach given these competing concerns. *See Wisconsin,* 938 F.3d at 320 (''EPA, though, possesses a measure of latitude in defining which upwind contribution 'amounts' count as 'significant[ ]' and thus must be abated.''). As noted in section VI.B.1.d of this document, the EPA finds that as long as state emissions budgets continue to reflect the required degree of emissions reductions at least for an interim period until the backstop rate would apply more uniformly, deferral of the backstop rate requirement for uncontrolled units in recognition of the transition period identified by commenters can be justified on the basis of the greater long-term environmental benefits obtained through greater compliance flexibility.

8. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

As emphasized by the D.C. Circuit in its decision invalidating CAIR, under the CAA's good neighbor provision, emissions ''within the State'' that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state must be prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The CAIR trading programs contained no provisions limiting the degree to which a state could rely on net purchased allowances as a substitute for making in-state emissions reductions, an omission which the court found was inconsistent with the requirements of the good neighbor provision. *Id.* In response to that holding, the EPA established the CSAPR trading programs' assurance provisions to ensure that, in the context of a flexible trading program, the emissions reductions required under the good neighbor provision in fact will take place within the state. The EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.

Unfortunately, the EPA also recognizes that the assurance provisions' very good historical compliance record is not good enough. The four past exceedances all occurred under the Group 2 trading program: sources in Mississippi collectively exceeded their applicable assurance levels in the 2019 and 2020 control periods, and sources in Missouri collectively exceeded their applicable assurance levels in the 2020 and 2021 control periods.[340] Both of the exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped,

[338] See 40 CFR 257.103(b).

[339] See 40 CFR 51.308(f).

[340] Information on the assurance level exceedances in the 2019, 2020, and 2021 control periods is available in the final notices concerning EPA's administration of the assurance provisions for those control periods. 85 FR 53364 (August 28, 2020); 86 FR 52674 (September 22, 2021); 87 FR 57695 (September 21, 2022).

coal-fired steam units had not chosen to idle the units' controls and rely instead on net out-of-state purchased allowances. The exceedances were large, and ample quantities of allowances to cover the resulting 3-for-1 allowance surrender requirements were purchased in advance, suggesting that the assurance level exceedances may have been anticipated as a possibility. In the case of the Mississippi exceedances, the exceedances were smaller, operational variability (manifesting as increased heat input) appears to have been a material contributing factor, and the EPA has not concluded that the owners and operators anticipated the exceedances. However, an additional contributing factor was the fact that several large, gas-fired steam units without SCR controls emitted NO_X at average rates much higher than the average emissions rates the same units had achieved in previous control periods. In short, while the Missouri exceedances appear far more significant, the EPA's analysis indicates that all four past exceedances could have been avoided if the units most responsible had achieved emissions rates more comparable to the same units' previous performance. In the EPA's view, the operation of the Missouri units in particular—although not prohibited by the current regulatory requirements—cannot be reconciled with the statutory requirements of the good neighbor provision. The fact that such operation is not prohibited by the current regulations therefore indicates a deficiency in the current regulatory requirements.

To correct the deficiency in the regulatory requirements, the EPA in this rulemaking is revising the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances starting with the 2024 control period. Because the pollutant involved is ozone season NO_X and the particular sources for which deterrence is most needed are located in states that are transitioning from the Group 2 trading program to the Group 3 trading program, the EPA is promulgating the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[341]

The two historical emissions-related compliance requirements in the Group 3 trading program regulations are both structured in the form of requirements to hold allowances. The first requirement applies at the source level: specifically, at the compliance deadline after each control period, the owners and operators of each source covered by the program must surrender a quantity of allowances that is determined based on the emissions from the units at the source during the control period. The second requirement applies at the designated representative level (which typically is the owner or operator level): if the state's sources collectively emit in excess of the state's assurance level, the owners and operators of each set of sources determined to have contributed to the exceedance must surrender an additional quantity of allowances. As long as a source's owners and operators comply with these two allowance surrender requirements (and meet certain other requirements not related to the amounts of the sources' emissions), they are in compliance with the program.

In light of the operation of the Missouri sources, the EPA is doubtful that strengthening the assurance provisions by increasing allowance surrender requirements at the unit, source, or designated representative level would create a sufficient deterrent. Accordingly, the EPA is instead adding a new, unit-level emissions limitation structured as a prohibition to emit NO_X in excess of a defined amount. A violation of the prohibition will not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but will trigger the possible application of the CAA's enforcement authorities. The new emissions limitation will be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point is being made explicit by relabeling the source-level allowance holding requirement, currently called the "emissions limitation," as the "primary emissions limitation" and labeling the new unit-level requirement as the "secondary emissions limitation." (The regulations label the designated representative-level requirement as "compliance with the . . . assurance provisions.")

Because the purpose of the new unit-level secondary emissions limitation is to deter conduct causing exceedances of a state's assurance level, the EPA is conditioning applicability of the new limitation on (1) the occurrence of an exceedance of the state's assurance level for the control period, and (2) the apportionment of at least some of the responsibility for the assurance level exceedance to the set of units represented by the unit's designated representative. Apportionment of responsibility for the assurance level exceedance will be carried out according to the existing assurance provision procedures and will therefore depend on the designated representative's shares of both the state's total emissions for the control period and the state's assurance level for the control period. To ensure that the secondary emissions limitation is focused on units where the need for improved incentives is greatest, and also to ensure that the limitation will not apply to units used only to meet peak electricity demand, the limitation applies only to units that are equipped with post-combustion controls (*i.e.,* SCR or SNCR) and that operated for at least ten percent of the hours in the control period in question and in at least one previous control period.

For units to which a secondary emissions limitation applies in a given control period based on the conditions just summarized, the limitation is defined by a formula in the regulations. The formula is generally designed to compute the potential amount the unit would have emitted during the control period, given its actual heat input during the control period, if the unit had achieved an average emissions rate equal to the unit's lowest average emissions rate in a previous control period plus a margin of 25 percent. To ensure that the data used to establish the unit's lowest previous average emissions rate are representative and of high quality, only past control periods where the unit participated in a CSAPR trading program for ozone season NO_X and operated in at least ten percent of the hours in the control period are considered. Further, to avoid causing units that achieve emissions rates lower than 0.08 lb/mmBtu from becoming subject to more stringent secondary emissions limitations in subsequent control periods, the secondary emissions limitation formula uses a

[341] The EPA believes that the occurrence of avoidable assurance level exceedances under the Group 2 trading program, combined with the express statutory directive that good neighbor obligations must be addressed "within the state," and through "prohibition," would also provide a sufficient legal basis for the Agency to promulgate the same revisions to the assurance provisions for all the other CSAPR trading programs. The EPA is not doing so at this time because the Agency has seen no reason to expect exceedances of the assurance levels under any of the other CSAPR trading programs by any of the states that will remain subject to the respective trading programs after this rulemaking, except possibly by Missouri under the CSAPR NO_X Annual Trading Program. The EPA expects that reductions in Missouri's seasonal NO_X emissions sufficient to comply with the proposed provisions of the revised Group 3 trading program, including the secondary emissions limitations, would also prevent exceedances of Missouri's currently applicable assurance level for annual NO_X emissions.

floor emissions rate of 0.10 lb/mmBtu (which is 0.08 lb/mmBtu plus the formula's 25 percent margin). In addition to making sure that performance better than 0.08 lb/mmBtu is not disincentivized, the inclusion of the floor emissions rate also ensures that no unit achieving an average emissions rate of 0.10 lb/mmBtu or less in a given control period will exceed a secondary emissions limitation in that control period. Finally, the formula includes a 50-ton threshold, which will avert violations for small performance deviations at large EGUs and also ensure that no unit emitting less than 50 tons in a given control period will exceed a secondary emissions limitation in that control period.

In summary, a secondary emissions limitation is applicable to a unit for a given control period only if the state's assurance level is exceeded, responsibility for the exceedance is apportioned at least in part to the set of units represented by the unit's designated representative, the unit is equipped with post-combustion controls, and the unit operated for at least ten percent of the hours in the control period. Where a secondary emissions limitation applies to a unit for a given control period, the amount of the limitation is computed as the sum of 50 tons plus the product of (1) the unit's heat input for the control period times (2) a NO_X emissions rate of 0.10 lb/mmBtu or, if higher, 125 percent times the lowest seasonal average NO_X emissions rate achieved by the unit in a previous control period when the unit participated in a CSAPR trading program for ozone season NO_X emissions and operated in at least ten percent of the hours in the control period.[342]

Table VI.B.8–1 shows the secondary emissions limitations that the formula would have produced and which units would have exceeded those limitations if the limitations and formula had been in effect for the Group 2 trading program in 2020 and 2021 when assurance level exceedances occurred in Missouri. Following consideration of comments, the EPA believes that in each case the formula functions in a reasonable manner, and the Missouri units identified as exceeding their respective secondary emissions limitations are sources for which an enforcement deterrent under CAA sections 113 and 304 would have been appropriate to compel better control of NO_X emissions. Table VI.B.8–1 does not show any units that would have been identified as subject to secondary emissions limitations in the case of the 2019 and 2020 assurance level exceedances in Mississippi because no units in the state meeting all conditions for applicability—including the requirement to be equipped with post-combustion controls—exceeded their respective limitations.

TABLE VI.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	125% of Lowest previously achieved NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
Missouri—2020						
Assoc. Elec. Coop	New Madrid 1	0.135	0.670	961	4,524	3,563
Assoc. Elec. Coop	New Madrid 2	0.131	0.497	866	3,108	2,242
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.526	374	1,384	1,010
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.537	548	2,187	1,639
Assoc. Elec. Coop	Thomas Hill 3	0.104	0.195	780	1,374	594
Missouri—2021						
Assoc. Elec. Coop	New Madrid 1	0.135	0.652	353	1,466	1,113
Assoc. Elec. Coop	New Madrid 2	0.131	0.611	1,054	4,700	3,646
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.146	421	440	19
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.400	600	1,801	1,201

For further illustrations of the application of the secondary emissions limitation formula to other units in the states to be subject to the expanded Group 3 trading program in the control periods from 2016 through 2021, see the spreadsheet ''Illustrative Calculations Using Proposed Secondary Emissions Limitation Formula,'' available in the docket. The EPA notes that, with the exception of the units listed in Table VI.B.8–1, no unit shown in the spreadsheet as having emissions exceeding the illustrative secondary emissions limitation calculated for the unit would have violated the prohibition because no violation would occur in the absence of an exceedance of the assurance level and apportionment of responsibility for a share of the exceedance to the unit under the assurance provisions.

The secondary emissions limitation provisions are being finalized as proposed except for the addition of the condition that a unit to which the provisions apply must be equipped with post-combustion controls. The EPA's responses to comments concerning the secondary emissions limitation provisions, including the comments giving rise to the change just mentioned, are in the remainder of this section and section 5 of the *RTC* document.

Comment: Some commenters stated that the secondary emissions limitation is not necessary, or would be a disproportionate remedy, because experience shows that exceedances of the assurance level have been rare, and where exceedances of a state's assurance level have occurred, the 3-for-1 surrender ratio under the existing regulations has applied, providing a sufficient remedy.

Response: The EPA disagrees with these comments. The purpose of the assurance provisions in the CSAPR trading programs is to ensure that the emissions reductions required to address a state's obligations under the Good Neighbor Provision occur ''within the state'' as mandated by the CAA. See *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). Prior to this action, the sole consequence for an exceedance of a state's assurance level

[342] For the actual regulatory language, see 40 CFR 97.1025(c) as added by this rule.

has been a requirement to surrender two additional allowances for each ton of the exceedance. The repeated, large, foreseeable, and easily avoidable exceedances of Missouri's assurance level under the Group 2 trading program in 2020 and 2021 have made clear that a remedy based solely on additional allowance surrenders is insufficient to address this statutory requirement and that a materially stronger deterrent is needed.

Comment: Some commenters stated that the secondary emissions limitation could apply to exceedances caused by factors outside the control of the EGU operator, going beyond the EPA's intent of deterring exceedances that are foreseeable and avoidable. For example, commenters pointed out that some units that typically combust gas may sometimes be ordered to combust oil at times when supplies of gas are constrained and expressed concern that the resulting higher NO_X emissions could cause a unit to exceed its secondary emissions limitation. Another commenter stated that it is not uncommon for units' seasonal average NO_X emissions rate to vary by more than 25 percent across control periods.

Response: The EPA agrees that the secondary emissions limitation is intended to apply to units in a position to avert an exceedance of a state's assurance level. The contention that year-to-year variability of 25 percent in units' seasonal average emissions rates is common is not in itself a persuasive reason to omit the secondary emissions limitation from the final rule, because the mere existence of such variability says nothing about whether the operators of those units could reduce that variability through their operational decisions, and the commenter provided no data regarding the extent to which the historical variability was avoidable. However, the EPA agrees that a secondary emissions limitation should be designed to avoid application to a unit whose increase in emissions rate was caused by mandated combustion of a higher-NO_X fuel than the unit's normal fuel. Moreover, based on the analysis of the secondary emissions limitation formula prepared for the proposal, the EPA has reviewed the applicability of the limitation more generally and has determined that it should apply only to units with post-combustion controls, which are the units with the greatest ability to manage their emissions rates through their operating behavior. This modification will avoid application of a secondary emissions limitation in situations where a unit's increase in seasonal average NO_X emissions rate relative to past control periods is caused by factors in that control period beyond the operator's control, such as being mandated by a regulator to combust a higher proportion of oil or operating for a higher proportion of hours at load levels where the unit has a higher NO_X emissions rate for reasons other than non-operation of emissions controls.

Comment: Some commenters asserted that because it is not known if a state's assurance level has been exceeded until after the end of the control period, EGU operators would be unable to know whether the secondary emissions limitation would apply to them during the control period. Some of these commenters suggested that where a unit has been found to have contributed to an assurance level exceedance, the EPA should apply a secondary emissions limitation to the unit not in that control period but instead in the following control period.

Commenters suggested that uncertainty about whether a unit would be subject to a secondary emissions limitation could have a variety of undesirable consequences. For example, they asserted that some EGUs could become unwilling to operate when needed for reliability because they would be concerned that merely operating more than in previous control periods could cause a unit to exceed its limitation. One commenter asserted that the uncertainty would make it difficult for an owner of multiple EGUs to use allowances allocated to one EGU to meet another EGU's surrender requirements, possibly leading to operating restrictions on multiple EGUs.

Response: The EPA disagrees with these comments. While an operator cannot be certain that the secondary emissions limitation *will* apply to a particular EGU until after the end of a control period, the operator can be certain that the limitation *will not* apply to a particular EGU simply by ensuring that the unit's seasonal average NO_X emissions rate does not exceed the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under a CSAPR trading program (excluding control periods where the unit operated for less than 10 percent of the hours). Because any operator of a unit with post-combustion controls can readily avoid being subject to the limitation, there is no need for application of the limitation to be deferred to the following control period. Deferral of the limitation's application would also have the effect of excusing a unit's first contribution to an assurance level exceedance, which the EPA views as inappropriate when that exceedance could have been avoided.

The asserted possible consequences of uncertainty about whether the limitation would apply rest on mischaracterizations of the provision. The formula for the limitation reflects the unit's actual heat input for the control period, so there is no penalty for increased operation as long as the unit's seasonal NO_X average emissions rate stays below the level just referenced. Finally, nothing about the secondary emissions limitation disincentivizes an EGU fleet owner from transferring allocated allowances among the fleet's EGUs, because apportionment of responsibility for an assurance level exceedance—one of the conditions for application of the secondary emissions limitation—is determined at the level of the group of units represented by a common designated representative (typically the set of all units operated by a particular owner) rather than the individual unit.

Comment: Some commenters stated that the EPA should revise the secondary emissions limitation formula so that where a limitation applies to a unit, the unit's previous NO_X emissions rate used in the formula would not be subject to any floor. These commenters also recommended that if the secondary emissions limitation provisions are not finalized, the EPA instead should raise the allowance surrender ratio applied to exceedances of the assurance level in this final rule.

Response: The EPA disagrees with the suggestion to remove the emissions rate floor from the secondary emissions limitation formula, which would have the effect of making the limitation more stringent for any unit that has achieved a seasonal average NO_X emissions rate lower than 0.08 lb/mmBtu in a past control period. As indicated by their label, the secondary emissions limitation provisions play a secondary role in the Group 3 trading program regulations, specifically to provide the strongest possible deterrent against conduct leading to foreseeable and avoidable exceedances of a state's assurance level. The distinguishing feature of the secondary emissions limitation provisions is therefore the remedy for an exceedance, which is potential application of the CAA's enforcement authorities. The trading program's primary role of achieving required emissions reductions in a more flexible and cost-effective manner than command-and-control regulation is played by the primary emissions limitation provisions, which are structured as allowance surrender requirements. Within this overall trading program structure, the EPA considers it sufficient for the operation of units at emissions rates lower than 0.08 lb/mmBtu to be incentivized through the allowance surrender requirements instead of being mandated through potential application of the CAA's enforcement authorities.

The recommendation to raise the allowance surrender ratio applicable to exceedances of the assurance level if the secondary emissions limitation is not finalized is moot because the secondary emissions limitation is being finalized.

9. Unit-Level Allowance Allocation and Recordation Procedures

In this rule, the EPA is establishing default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances ("Group 3 allowances") in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. Like the allocation processes established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised allocation process finalized in this rule is designed to provide default allowance allocations to all units that are subject to allowance holding requirements. The EPA's allocations and allocation procedures apply for the 2023 control period [343] and, by default, for subsequent control periods unless and until a state or tribe provides state-determined or tribe-determined allowance allocations under an approved SIP revision or tribal implementation plan.[344]

The default allocation process for the Group 3 trading program as updated in this rule involves three main steps. First, portions of each state emissions budget for each control period are reserved for potential allocation to units that are subject to allowance holding requirements and that might not otherwise receive allowance allocations in the overall allocation process, including both "existing" units in any areas of Indian country not subject to a state's CAA implementation planning authority as well as "new" units anywhere within a state's borders.[345] Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible existing units, any portion of the state budget reserved for existing units in Indian country not subject to the state's CAA implementation planning authority is allocated among those units, and the allocations are recorded in the respective sources' compliance accounts. Finally, after the control period but before the compliance deadline by which sources must hold allowances to cover their emissions for the control period, allowances from the portion of the budget reserved for new units are allocated to qualifying units, any remaining reserved allowances not allocated to qualifying units are allocated among the state's existing units, and the allocations are recorded in the respective sources' compliance accounts.

While the overall three-step allocation process summarized in this section was also followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rule the EPA is making revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the dynamic budget-setting process discussed in section VI.B.4 of this document. The revisions to the three steps are discussed in sections VI.B.9.a, VI.B.9.b, and VI.B.9.c, respectively.

a. Set-Asides of Portions of State Emissions Budgets

The first step of the overall unit-level allocation process for a given control period involves reserving portions of each state's budget for the control period in "set-asides." In this rule, the EPA is making several revisions affecting the establishment of set-asides. The first revision, which is largely unrelated to the other aspects of this rulemaking, will update the regulations for the Group 3 trading program [346] to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that the relevant states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area.[347] Consistent with this holding, the EPA is revising language in the Group 3 trading program regulations that prior to this rule, for purposes of allocating allowances from a given state's emissions budget, distinguished between (1) the set of units within the state's borders that are not in Indian country and (2) the set of units within the state's borders that are in Indian country. As revised, the provisions now distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. The revised language more accurately distinguishes which units are, or are not, covered by a state's CAA implementation planning authority, which is the underlying purpose for which the term "Indian country" is currently used in the allowance allocation provisions. The effect of the revision is that any units located in areas of "Indian country" as defined in 18 U.S.C. 1151 that are covered by a state's CAA implementation planning authority will be treated for allowance allocation purposes in the same manner as units in areas of the state that are not Indian country, consistent with the *ODEQ* holding.[348]

The remaining revisions, which are interrelated, concern the types of set-asides that in the context of this rule will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would

[343] The rule does not include an option for states to replace the EPA's unit-level allocations for the 2023 control period because the Agency believes a process for obtaining appropriately authorized allowance allocations determined by a state or tribe could not be completed in time for those allocations to be recorded before the end of the 2023 control period.

[344] The options for states to submit SIP revisions that would replace the EPA's default allowance allocations are discussed in sections VI.D.1, VI.D.2, and VI.D.3 of this document. Similarly, for a covered area of Indian country not subject to a state's CAA implementation planning authority, a tribe could elect to work with the EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations that would replace the EPA's default allocations for subsequent control periods.

[345] Under this rule, the unit-level allocations to "existing" units are generally computed in the year before the year of each control period, and the determination of whether to treat a particular unit as existing for purposes of that control period's allocations is made as part of the allocation process, generally based on whether the Agency has the data needed to compute an allocation for the unit as an existing unit. A unit that is subject to allowance holding requirements for a given control period and that did not receive an allocation for that control period as an existing unit is generally eligible to receive an allocation from the portion of the budget reserved for "new" units. For further discussion of which units are considered eligible for allocations as existing units or new units in particular control periods, see sections VI.B.9.b and VI.B.9.c.

[346] As discussed in section VI.B.13, the EPA is also making this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

[347] For additional discussion of the *ODEQ* v. *EPA* decision and other issues related to the CAA implementation planning authority of states, tribes, and the EPA in various areas of Indian country, *see* section III.C.2.

[348] The EPA notes that the units that will be treated for allocation purposes in the same manner as units not in Indian country will include units in any areas of Indian country subject to a state's CAA implementation planning authority, whether those are non-reservation areas (consistent with *ODEQ*) or reservation areas (such as areas of Indian country within Oklahoma's borders covered by the EPA's October 1, 2020 approval of Oklahoma's request under SAFETEA, as discussed in section III.C.2).

not otherwise receive allowance allocations. One revision to the types of set-asides addresses allocations to existing units in Indian country. The revised geographic scope of the Group 3 trading program under this rule will for the first time include an existing EGU in Indian country not covered by a state's CAA implementation planning authority—the Bonanza coal-fired unit in the Uintah and Ouray Reservation within Utah's borders. To provide an option for Utah (or a similarly situated state in the future) to replace the Agency's default allowance allocations to most existing units with state-determined allocations through a SIP revision while continuing to ensure the availability of a default allocation to the Bonanza unit, which is not subject to the state's jurisdiction or control (or similarly situated units in the future), the EPA is revising the Group 3 trading program regulations to provide for "Indian country existing unit set-asides." Specifically, for each state and for each control period where the set of units within a state's borders eligible to receive allocations as existing units includes one or more units [349] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA will reserve a portion of the state's emissions budget in an Indian country existing unit set-aside for the unit or units. The amount of each Indian country existing unit set-aside will equal the sum of the default allocations that the units covered by the set-aside would receive if the allocations to all existing units within the state's borders were computed according to EPA's default allocation procedure (which is discussed in section VI.B.9.b of this document). Immediately after determining the amount of a state's emissions budget for a control period (and after reserving a portion for potential allocation to new units, as discussed later in this section), the EPA will first determine the default allocations for all existing units within the state's borders, then allocate the appropriate quantity of allowances to the Indian country existing unit set-aside, then allocate the allowances from the set-aside to the covered units in Indian country, and finally record the allocations in the sources' compliance accounts at the same time as the allocations to other sources not in Indian country. The existence of the Indian country existing unit set-aside thus will have no substantive effect unless and until the relevant state chooses to replace the EPA's default allowance allocations through a SIP revision, in which case the state would have the ability to establish state-determined allocations for the units subject to the state's CAA implementation planning authority while the EPA would continue to administer the Indian country existing unit set-aside for the units in Indian country not covered by the state's CAA implementation planning authority.[350] The EPA believes the establishment of Indian country existing unit set-asides accomplishes the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while ensuring that the allocations to units in Indian country not covered by such authority remain under Federal authority (unless replaced by a tribal implementation plan).

The remaining revisions to the types of set-asides address the set-asides used to ensure availability of allowance allocations to *new* units in light of the division of the budget for *existing* units into a reserved portion for existing units in Indian country and an unreserved portion for other existing units. Under the Group 3 trading program regulations as in effect before this rule, allowances for new units have been provided from separate new unit set-asides and Indian country new unit set-asides. Under this rule, the EPA is combining these two types of set-asides starting with the 2023 control period by eliminating the Indian country new unit set-asides and expanding eligibility for allocations from the new unit set-asides to include units anywhere within the relevant states' borders. However, as with the Indian country new unit set-asides under the current regulations, the EPA will continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, thereby ensuring the availability of allocations to any new units not covered by a state's CAA implementation planning authority.

The reason for the revisions to the new unit set-asides and Indian country new unit set-asides is to avoid unnecessary and potentially inequitable changes to the degree to which individual existing units contribute to, or benefit from, the new unit set-asides. The allowances used to establish these set-asides are reserved from each state emissions budget before determination of the allocations from the unreserved portion of the budget to existing units, so that certain existing units—generally those receiving the largest allocations—contribute to creation of the set-asides through roughly proportional reductions in their allocations. Later, if any allowances in a set-aside are not allocated to qualifying new units, the remaining allowances are reallocated to the existing units in proportion to their initial allocations from the unreserved portion of the budget, so that certain existing units—again, generally those receiving the largest allocations—benefit from the reallocations in rough proportion to their previous contributions.[351] The EPA believes maintaining this symmetry, where the same existing units—whether in Indian country or not—both contribute to and potentially benefit from the set-asides, is a reasonable policy objective, and doing so requires that the EPA continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to maintain Federal implementation authority and ensure that the units in Indian country would receive an appropriate share of any reallocated allowances.[352] The principal difference between the new unit set-asides and the Indian country new unit set-asides under the regulations in effect before this rule was that, if a state chose to replace the EPA's default allocations with state-determined allocations, the state would take over administration of the new unit set-aside, but not any Indian country new unit set-aside.

[349] In coordination with the dynamic budgeting process discussed in section VI.B.4, each unit included in the unit inventory used to determine a state's dynamic emissions budget for a given control period in 2026 or a later year will be considered an "existing" unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there will no longer be a single fixed date that divides "existing" from "new" units.

[350] As noted in section VI.D, a tribe could elect to work with EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations for units in the relevant area of Indian country that would replace EPA's default allocations for subsequent control periods.

[351] Under the regulations in effect before this final rule, allowances from an Indian country new unit set-aside that are not allocated to qualifying new units in Indian country are first transferred to the state's new unit set-aside, and if the allowances are not allocated to qualifying new units elsewhere within the state's borders, the allowances are then reallocated to the state's existing units.

[352] If units in Indian country were unable to share in the benefits of reallocation of allowances from the new unit set-asides, it would be possible to achieve a different form of symmetry by simultaneously exempting the units in Indian country from the obligation to share in the contribution of allowances to the new unit set-asides. However, some stakeholders might view this alternative as potentially inequitable because existing units in Indian country would then make no contributions toward the new unit set-aside while other existing units would still be required to do so.

Under the revised regulations finalized in this rule, states will not be able to take over administration of the new unit set-asides in this situation. Therefore, there is no longer any reason to establish separate Indian country new unit set-asides in order to preserve Federal (and potentially tribal) authority to implement the rule in areas of Indian country subject to tribal jurisdiction.

With respect to the total amounts of allowances that will be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 through 2025 (but not for subsequent control periods, as discussed later in this section), the EPA is establishing total set-aside amounts equal to the projected amounts of emissions from any planned units in the state for the control period, plus an additional base 2 percent of the state emissions budget to address any unknown new units, with a minimum total amount of 5 percent. For example, if planned units in a state are projected to emit 4 percent of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 6 percent, which is the sum of the 4 percent for planned units plus the base 2 percent for unknown new units. Alternatively, if planned new units are projected to emit only 1 percent of the state's budget, the new unit set-aside would be set at the minimum 5 percent amount. Except for the addition of the 5 percent minimum, which is a change being made in response to comments, the approach to setting the new unit set-aside amounts is generally the same approach previously used to establish the amounts of new unit set-asides in CSAPR, the CSAPR Update, and the Revised CSAPR Update for all the CSAPR trading programs. *See, e.g.,* 76 FR 48292 (August 8, 2011).

As under the Revised CSAPR Update, the EPA is making an exception for New York for the 2023 through 2025 control periods, establishing a total new unit set-aside amount for each control period of 5 percent of the state's emissions budget, with no additional consideration for planned units, because this approach is consistent with New York's preferences as reflected in an approved SIP addressing allowance allocations for the Group 2 trading program.

The final regulations issued under this rule specify the new unit set-aside amounts in terms of the percentages of the state emissions budgets. The amounts are shown in Tables VI.B.9.a–1, VI.B.9.a–2, and VI.B.9.a–3 of this document show the tonnage amounts of the new unit set-asides for the control periods in 2023 through 2025 that are computed by multiplying the new unit set-aside percentages by the preset budgets finalized in this rule for those control periods. The amounts of the 2023 new unit set-asides are illustrative because they do not reflect the impact of transitional adjustments included in the rule that that are likely to affect the 2023 budgets as implemented.[353] The amounts of the 2024 and 2025 new unit set-asides are the actual amounts, because the 2024 and 2025 budgets computed in this rule are the budgets that will be implemented, without any need for transitional adjustments.

TABLE VI.B.9.a–1—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,379	5	319
Arkansas	8,927	5	446
Illinois	7,474	5	374
Indiana	12,440	5	622
Kentucky	13,601	5	680
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,727	5	536
Minnesota	5,504	5	275
Mississippi	6,210	5	311
Missouri	12,598	5	630
Nevada	2,368	9	213
New Jersey	773	5	39
New York	3,912	5	196
Ohio	9,110	6	547
Oklahoma	10,271	5	514
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,755	5	788
Virginia	3,143	5	157
West Virginia	13,791	5	690
Wisconsin	6,295	5	315

[353] As discussed in section VI.B.12, the EPA expects that this final rule will become effective after May 1, 2023, causing the emissions budgets for the 2023 control period to be adjusted under the rule's transitional provisions so as to ensure that the new budgets will apply only after the rule's effective date. The actual new unit set-asides for the 2023 control period will be computed using the adjusted budgets, but the 2023 budget amounts shown in Table VI.B.9.a–1 do not reflect these adjustments.

TABLE VI.B.9.a–2—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2024 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,999	5	650
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,058	5	253
Missouri	11,116	5	556
Nevada	2,589	9	233
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,384	5	469
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	6,295	5	315

TABLE VI.B.9.a–3—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2025 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,472	5	624
Louisiana	9,107	5	455
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,037	5	252
Missouri	11,116	5	556
Nevada	2,545	9	229
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,376	5	469
Pennsylvania	8,138	5	407
Texas	38,542	5	1,927
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	5,988	5	299

For control periods in 2026 and later years, the EPA will allocate a total of 5 percent of each state emissions budget to a new unit set-aside, with no additional amount for planned new units. The amounts of the set-asides for each state and control period will be computed when the emissions budgets for the control period are established, by May 1 of the year before the year of the control period. The procedure for determining the amounts of the set-asides based on the amounts of the state emissions budgets is being codified in the Group 3 trading program regulations and will reflect the same percentage of the emissions budget for all states.

The purpose of the change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that may be used to determine budgets beginning with the 2026 control period. As discussed in section VI.B.4 of this document, under the dynamic budget-setting process, each state's budget for each control period will be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the most recent control periods before the budget-setting computations. (For example, 2026 emissions budgets would be based on 2022–2024 state-level heat input data.) Moreover, as discussed in section VI.B.9.b of this document, the set of units eligible to receive allocations as ''existing'' units in a given control period will generally be the set of units that operated in the control period two years earlier (with the exception of any units whose monitor certification deadlines fell after the start of that earlier control period). Consequently, by the 2025 control period, all or almost all units that commenced commercial operation before issuance of this rule will be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of this rule generally will be considered ''existing'' units for all but their first two full control periods of operation (and possibly a preceding partial control period). Given that new units will not be relying on the new unit set-asides as a permanent source of allowances, as is the case for ''new'' units under the other CSAPR trading programs, the EPA believes it is unnecessary to establish set-aside percentages for some states that are permanently larger than 5 percent based solely on the fact that projected emissions from planned new units happen to be a somewhat larger proportion of those states' overall budgets at the time of this rule's issuance.

The changes to the structure and amounts of set-asides in this rule largely follow the proposal. The EPA received few comments on these topics. As noted previously, one commenter expressed the view that if the amounts of the new unit set-asides were based on 2 percent of the respective states' budgets, the set-asides would be too small in certain circumstances, and in response the final rule bases the amounts of the set-asides on a floor percentage of 5 percent instead of 2 percent. The remaining commenters expressed a concern that the final rule's provisions regarding set-asides should ensure that any tribal decisions relating to allowance allocations would not be constrained by state decisions. The EPA had this same concern in mind when designing the rule and believes that the final set-aside structure—encompassing Indian country existing unit set-asides as well as EPA-administered new unit set-asides for sources in all areas within each state's borders—fully addresses the concern, is equitable, and preserves Federal and tribal authority under this rule for areas of Indian country subject to tribal jurisdiction. The comments and the EPA's responses are discussed in greater detail in section 1 of the *RTC* document.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budget-setting methodology for the Group 3 trading program finalized in this rulemaking, the EPA is necessarily establishing a revised procedure for making unit-level allocations of Group 3 allowances to existing units.[354] The procedure that the EPA is employing to compute the unit-level allocations is very similar but not identical to the procedure used to compute unit-level allocations for units subject to the Group 3 trading program in the Revised CSAPR Update. The steps of the procedure for determining allocations from each state emissions budget for each control period are described in detail in the Unit-Level Allowance Allocations Final Rule TSD. The steps are summarized in the following paragraphs, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA identifies the list of units eligible to receive allocations for the control period. The unit inventories used to compute unit-level allocations for the control periods in 2023 through 2025 are the same inventories that have been used to determine the preset emissions budget for these control periods. These inventories have been determined in this rulemaking in essentially the same manner as in the Revised CSAPR Update. The procedures for updating the unit inventories for these control periods are discussed in section VI.B.4 of this document, and the criteria that the EPA has applied to determine whether a unit's scheduled retirement is sufficiently certain to serve as a basis for adjusting emissions budgets and unit-level allocations, are discussed in section V.B of this document and in the Ozone Transport Policy Analysis Final Rule TSD.

The unit inventories used to compute unit-level allocations for control periods in 2026 and later years will be determined in the year before the control period in question based on the latest reported emissions and operational data, which is an extension of the methodology used in the Revised CSAPR Update to reflect more recent data (for example, the unit inventories used to compute 2026 budgets and allocations will reflect reported data up through the 2024 control period). These inventories, which are generally the same as the inventories used to compute dynamic budgets for each control period, include any unit whose monitor certification deadline was no later than the start of the relevant historical control period and that reported emissions data during the relevant historical control period. The EPA notes that basing the list of eligible units on the list of units that reported heat input in the control period two years earlier than the control period for which allocations are being determined represents a revision to the Group 3 trading program regulations as in effect before this rule concerning the treatment of allocations to retired units. Under the prior regulations, units that cease operations for two consecutive control periods would continue to receive allocations as existing units for three additional years (that is, a total of five years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the regulations as revised in this rule, units that cease operation will receive allocations for only two full control periods of non-operation. While the EPA has in prior transport rulemakings noted a qualitative concern that ceasing allowance allocations prematurely could distort the economic incentives of EGUs to continue operating when retirement is more economical, the EPA believes that anticipated market conditions (in particular, the incentives toward power sector transition to cleaner generating sources), particularly in the later 2020s, are such that a continuation of allowance allocations to retiring units likely has no more than a de minimis effect on the consideration of an EGU whether to retire or not.

In the second step of the procedure for determining allocations to existing units, the EPA will compile a database containing for each eligible unit the unit's historical heat input and total NO_X emissions data for the five most recent ozone seasons. For each unit, the EPA will compute an average heat input value based on the three highest non-zero heat input values over the 5-year period, or as the average of all the non-zero values in the period if there are fewer than three non-zero values. For each unit, the EPA will also determine the maximum total NO_X emissions value over the 5-year period. For coal-

[354] The revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading program. In this rulemaking, the EPA is not reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

fired units of 100 MW or larger, the EPA will further determine a ''maximum controlled baseline'' NO_X emissions value, computed as the unit's maximum heat input over the 5-year period times a NO_X emissions rate of 0.08 lb/mmBtu. The maximum controlled baseline will serve as an additional cap on unit-level allocations for all such coal-fired units starting with the control periods in which the assumed use of SCR controls at the units is reflected in the state emissions budgets. Thus, the maximum controlled baseline will apply for purposes of allocations to units with existing SCR controls for all control periods starting with the 2024 control period and for all other coal-fired units of 100 MW or more (except circulating fluidized bed units) starting with the 2027 control period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with three exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA will use data from the most recent five control periods for which data had been reported. (For example, for the 2026 control period, the EPA will use data for the 2020–2024 control periods.) Second, to simplify the data compilation process, the EPA will use only a five-year period for NO_X mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO_X mass emissions. Third, the use of the maximum controlled baseline as an additional cap on emissions is a change adopted in this rule in response to comments received on the proposal. Specifically, commenters observed that if a state's emissions budget is decreased to reflect an assumption that a particular unit in the state is capable of reducing its emissions through the installation of new SCR controls, but the historical emissions cap applied to that unit in the unit-level allocation methodology does not reflect use of the new controls, then the allocation methodology could have the effect of reducing unit-level allocations to the other units in the state whose historical emissions already reflect use of existing controls rather than the unit assumed to install new controls. The EPA agrees with the comment and in this rule has added the maximum controlled baseline provision to the allocation methodology to mitigate the potential effect identified by the commenters.

In the third step of the procedure for determining allocations to existing units in each state, the EPA will allocate the available allowances for that state among the state's eligible units in proportion to the share each unit's average heat input value represents of the total of the average heat input values for all the state's eligible units, but not more than the unit's maximum total NO_X value or, if applicable, the unit's maximum controlled baseline. If the allocations to one or more units are curtailed because of the units' applicable caps, the EPA will iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their caps. (If all units in a state reach their caps, any remaining allowances are allocated in proportion to the units' average heat input values, notwithstanding the caps.) This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR), but using caps that reflect both the units' maximum historical NO_X values and also, where applicable, the maximum controlled baseline values.

Illustrative unit-level allocations for the 2023 control period and final unit-level allocations for the 2024 and 2025 control periods are being determined in this rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and are included in the docket. The 2023 allocations are only illustrative because, as discussed in section VI.B.12.a, the EPA expects the effective date of the rule to occur after the start of the 2023 control period and consequently expects the 2023 control period to be a transitional period in which the emissions budgets determined in this rulemaking apply only for the portion of the control period occurring on and after the rule's effective date, while any previously determined emissions budgets apply for the portion of the control period before the rule's effective date. The rule's effective date will become known when the rule is published in the **Federal Register**. As soon as practicable thereafter, the EPA will calculate the final prorated or blended 2023 state emissions budgets and 2023 unit-level allocations based on the transitional formulas finalized in this action (see section VI.B.12.a of this document) and will communicate the information to the public through a notice of data availability. The 2023 and 2024 allocations will then be recorded 30 days after the effective date of the final rule (to provide an interval in which to execute the recall of 2023 and 2024 Group 2 allowances, as discussed in section VI.B.12.c of this document), while the 2025 allocations will be recorded by July 1, 2024.[355]

The default unit-level allocations for each control period in 2026 or a later year will be computed immediately following the determination of the state emissions budgets for the control period. The EPA will perform the computations and issue a notice of data availability concerning the preliminary unit-level allocations for each control period by March 1 of the year before the control period. There will be a 30-day period in which objections to the data and preliminary computations may be submitted, and the EPA will then make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA will then record the allocations by July 1 of the year before the control period.[356]

All covered states also have options to establish state-determined allowance allocations for control periods in 2024 and later years. As discussed in section VI.D.1 of this rule, a state choosing to establish state-determined allocations for the 2024 control period would need to submit a letter of intent to the EPA by August 4, 2023, and would need to submit the SIP revision with the allocations by September 1, 2023. The EPA would defer recordation of the 2024 allocations for the state's sources until March 1, 2024, to provide time for this process to be completed. As discussed in sections VI.D.2 and VI.D.3 of this rule, a state choosing to establish state-determined allocations for control periods in 2025 and later years would need to submit a SIP revision by December 1 of the year two years before the first year for which state-determined allocations are being established—*e.g.,* by December 1, 2023, for allocations for the 2025 control period—and would need to submit the allocations for each control period by June 1 of the year before the control period—*e.g.,* by June 1, 2024, for allocations for the 2025

[355] The recordation schedule for the 2023 and 2024 allocations represents an expected acceleration of the recordation schedule in effect immediately before this final rule, which called for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded by September 1, 2023. *See* Deadlines for Submission and Recordation of Allowance Allocations Under the Cross-State Air Pollution Rule (CSAPR) Trading Programs and the Texas SO_2 Trading Program (the ''Recordation Rule''), 87 FR 52473 (August 26, 2022).

[356] The current recordation schedule, which provides for almost all allowance allocations to existing units for a given control period under all the CSAPR trading programs to be recorded by July 1 of the year before the year of that control period, was adopted in the Recordation Rule.

control period.[357] The EPA would record any state-determined allocations for control periods in 2025 and later years by July 1 of the year before the control period, simultaneously with the recordation of allocations to units in states where the EPA determines the unit-level allocations.

The EPA notes that for the three states with approved SIP revisions establishing their own methodologies for allocating Group 2 allowances—Alabama, Indiana, and New York—the EPA will follow the states' methodologies to the extent possible in developing the EPA's allocations of Group 3 allowances to the units in those states for the control periods in 2023 through 2025.[358] The EPA will not follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2026 or later years. However, like other states, these three states have options to replace the EPA's default allocations with state-determined allocations through SIP revisions starting with the 2024 control period.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA will not record any allocations of Group 3 allowances in a source's compliance account unless that source has complied with the requirements to surrender previously allocated 2023–2024 Group 2 allowances. The surrender requirements are necessary to maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this final rule. The EPA finds that it is reasonable to condition the recordation of Group 3 allowances on compliance with the surrender requirements because the condition will spur compliance and will not impose an inappropriate burden on sources. The EPA considers establishment of this condition, which will facilitate the continued functioning of the Group 2 trading program, to be an appropriate exercise of the Agency's authority under CAA section 301 (42 U.S.C. 7601) to prescribe such regulations as are necessary to carry out its functions under the Act.

The provisions governing allocations to existing units are being finalized substantially as proposed, except for the addition of an additional cap on unit-level allocations in response to comments. The EPA's responses to comments on the unit-level allocation provisions for existing units are in section 5 of the *RTC* document.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

The Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside after the end of the control period at issue. An eligible new unit for purposes of allocations from a set-aside for a given control period is generally any unit in the relevant area that reported emissions subject to allowance surrender requirements during the control period and that was not eligible to receive an allowance allocation as an "existing" unit for the control period. Thus, in addition to units that have not yet completed two full control periods of operation since their monitor certification deadlines, units eligible for allocations from the new unit set-asides may also include existing coal-fired units that first lose their eligibility for allocations from the unreserved portion of the applicable state budget by ceasing operation, and then resume operation in a later control period. The regulations call for the EPA to allocate allowances to any eligible "new" units in the state generally in proportion to their respective emissions during the control period, up to the amounts of those emissions if the relevant set-aside contains sufficient allowances, and not exceeding those emissions. However, in the case of a unit whose allocation for the control period would have been subject to a maximum controlled baseline if the unit was eligible to receive allocations as an existing unit, the unit's allocation from the new unit set-aside will not exceed a cap equal to the unit's reported heat input for the control period times an emissions rate of 0.08 lb/mmBtu.

Any allowances remaining in a new unit set-aside after the allocations to new units are reallocated to the existing units in the state in proportion to those units' previous allocations for the control period as existing units. The EPA issues a notice of data availability concerning the proposed allocations by March 1 following the control period, provides an opportunity for submission of objections, and issues a final notice of data availability and record the allocations by May 1 following the control period, one month before the June 1 compliance deadline.

This EPA notes that the revisions to other provisions of the Group 3 trading program regulations discussed elsewhere in this document will reduce the portions of the state emissions budgets that are allocated through the new unit set-asides. Specifically, because the new unit set-asides will no longer receive any additional allowances when units retire, for control periods in 2025 and later years the amounts of allowances in the new unit set-asides will always be 5 percent of the respective state emissions budgets for the respective control periods. This limit on growth of the new unit set-asides is appropriate given that the number of consecutive control periods for which any particular unit is likely to receive allocations from a state's new unit set-aside will be reduced to two full control periods (and possibly a partial control period before those two control periods) before the unit becomes eligible to receive allocations as an "existing" unit from the unreserved portion of the state's emissions budget. This approach contrasts with the approach under the other CSAPR trading programs where a new unit never becomes eligible to receive allocations from the unreserved portion of the emissions budget and where the new unit set-aside therefore needs to grow to accommodate an ever-increasing share of the state's total emissions.

The EPA also notes that, as discussed in sections VI.D.2 and VI.D.3 of this document, in the event that a state chooses to replace EPA's default allowance allocations under the Group 3 trading program with state-determined allocations through a SIP revision, the EPA will continue to administer the portion of each state emissions budget reserved in a new unit set-aside to ensure the availability of allowance allocations to new units in any areas of Indian country within the state not covered by the state's CAA implementation planning authority.

The final rule's provisions concerning unit-level allocations from the new unit set-asides are unchanged from the proposal except for the addition of the allocation cap in a given control period for any unit that would have been subject to a maximum controlled baseline if the unit was eligible to receive an allocation as an existing unit

[357] The current deadlines for states to submit state-determined allowance allocations to the EPA were adopted in the Recordation Rule and are coordinated with the schedule for computation of state emissions budgets for control periods in 2026 and later years. For example, for the 2026 control period, by May 1, 2025, the EPA will publish the final state emissions budgets and the EPA's default unit-level allocations; by June 1, 2025, states will submit any state-determined unit-level allocations that would replace the default allocations; and by July 1, 2025, the EPA will record the default unit-level allocations or the state-determined unit-level allocations, as applicable, in sources' compliance accounts.

[358] For discussion of how the EPA is using the previously approved allocation methodologies for Alabama, Indiana, and New York to determine allocations to units in these states for the 2023–2025 control periods, see the Allowance Allocation Final Rule TSD.

for that control period.[359] This change was made to address the same comments discussed in section VI.B.9.b of this document that caused the Agency to add the maximum controlled baseline provision to the procedure for allocating allowances to existing units. The Agency did not receive any other comments on the proposed provisions concerning unit-level allocations of allowances from the new unit set-asides.

d. Incorrectly Allocated Allowances

The Group 3 trading program regulations as promulgated in the Revised CSAPR Update include provisions addressing incorrectly allocated allowances. With regard to any allowances that were incorrectly allocated and are subsequently recovered, the provisions as in effect prior to this rule have generally called for the recovered allowances to be reallocated to other units in the relevant state (or Indian country within the borders of the state) through the process for allocating allowances from the new unit set-aside (or Indian country new unit set-aside) for the state. If the procedures for allocating allowances from the set-asides have already been carried out for the control period for which the recovered allowances were issued, the allowances would be allocated through the set-asides for subsequent control periods.

The EPA continues to view the current provisions for disposition of recovered allowances as reasonable in the case of any allowances that are recovered before the deadline for recording allocations of allowances from the new unit set-aside for the control period for which the recovered allowances were issued. However, in the case of any allowances that are recovered after that deadline, adding the recovered allowances to the new unit set-aside for a subsequent control period, as provided in the current regulations, would be inconsistent with the trading program enhancements discussed elsewhere in this document, where the amounts of allowances provided in the state emissions budgets for each control period are designed to reflect the most current available information on fleet composition and utilization and where the quantities of banked allowances available for use in each control period are recalibrated for consistency with the state emissions budgets. The EPA is therefore finalizing revisions to provide that, starting with allowances allocated for the 2024 control period, any incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-aside for that control period (*i.e.,* May 1 of the year following the control period) will be transferred to a surrender account instead of being reallocated to other units in the state. The EPA received no comments on this proposed revision, which is being finalized as proposed.

10. Monitoring and Reporting Requirements

The Group 3 trading program requires monitoring and reporting of emissions and heat input data in accordance with the provisions of 40 CFR part 75. Under 40 CFR part 75, a given unit may have several options for monitoring and reporting. Any unit can use CEMS. Qualifying gas- or oil-fired units can use certain excepted monitoring methodologies that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data. Certain non-coal-fired, low-emitting units can use a low mass emissions (LME) methodology, and sources can seek approval of alternative monitoring systems approved by the Administrator through a petition process. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied to produce a conservative estimate of emissions for the period involved. Further, 40 CFR part 75 requires electronic submission of quarterly emissions reports to the Administrator, in a format prescribed by the Administrator. The quarterly reports will contain all the data required concerning ozone season NO_X emissions under the Group 3 trading program.

In this rulemaking, as proposed, the EPA is making two changes to the Group 3 trading program's previous requirements related to monitoring, recordkeeping, and reporting. First, the EPA is revising the monitor certification deadline in the Group 3 trading program regulations applicable to certain units that have not already certified monitoring systems for use under 40 CFR part 75. This revision is expected to provide approximately 15 EGUs in Nevada and Utah with 180 days following the rule's effective date to certify monitoring systems, with the consequence that the units are expected to become subject to allowance holding requirements under the Group 3 trading program starting with the 2024 control period. Second, to implement the trading program enhancements, the EPA is adding certain new recordkeeping and reporting requirements, which will be implemented through amendments to the regulations in 40 CFR part 75 and will apply starting January 1, 2024. Sources generally will be able to meet the additional recordkeeping and reporting requirements using the data that are already collected by their current monitoring systems, and the EPA is not requiring the installation of additional monitoring systems at any source. However, a small number of sources with common stacks could find it advantageous to upgrade their monitoring systems so as to monitor at the individual units instead of monitoring at the common stack. The Group 3 trading program monitor certification deadline revisions and the additional recordkeeping and reporting requirements are discussed in sections VI.B.10.a and VI.B.10.b, respectively.[360]

a. Monitor Certification Deadlines

In general, a unit subject to the Group 3 trading program must monitor and report emissions data using certified monitoring systems starting as of the date the unit enters the trading program or, if later, 180 days after the unit commences commercial operation. Where an EGU has already certified and maintained monitoring systems in accordance with 40 CFR part 75 for purposes of another trading program, no recertification solely for purposes of entering the Group 3 trading program is required. Under these pre-existing provisions of the Group 3 trading program regulations, nearly all currently operating EGUs transitioning to the trading program under this rule are positioned to begin monitoring and reporting under the trading program as of their dates of entry (or if later, 180 days after they commence commercial operation) because of the units' previous requirements to monitor and report emissions under other programs including the CSAPR NO_X Ozone Season Group 2 Trading Program (for

[359] As discussed in section IX.B of this rule, the EPA is relocating some of the regulatory provisions relating to administration of the new unit set-asides and is also removing certain provisions that are made obsolete by revisions to other provisions of the Group 3 trading program regulations.

[360] The EPA is not amending the existing provisions of the Group 3 trading program regulations that govern whether units covered by the program must record and report required data on a year-round basis or may elect to record and report required data on an ozone season-only basis. *See* 40 CFR 97.1034(d)(1); *see also* 40 CFR 75.74(a)-(b). Thus, for units that are required or elect to report other data on a year-round basis, the additional recordkeeping and reporting requirements will also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the additional requirements will also apply for the ozone season only.

units in Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), the CSAPR NO_X Annual Trading Program (for units in Minnesota), and the Acid Rain Program (for most units in Nevada and Utah).

As discussed in section VI.B.3 of this document, the EPA has identified 15 potentially affected units in Nevada and Utah that commenced commercial operation more than 180 days before the effective date of this rule and that do not currently report emissions data to the Agency under 40 CFR part 75.[361] To ensure that units in this situation have sufficient time to certify monitoring systems as required under this rule, the final rule establishes a monitoring certification deadline of 180 days after the effective date of the rule for affected units that are not already required to report emissions under 40 CFR part 75 under another program, equivalent to the 180-day window already provided to units commencing commercial operation after (or less than 180 days before) the final rule's effective date. The 180th day for units in this situation will likely fall after the end of the 2023 ozone season, with the result that the certification deadline will be extended until May 1, 2024, the first day of the 2024 ozone season. Because the Group 3 trading program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently will become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.

The EPA received no comments on the provisions establishing a monitor certification deadline 180 days after the effective date of this rule for affected units that are not already required to report emissions under 40 CFR part 75, and the provisions are being finalized as proposed.

b. Additional Recordkeeping and Reporting Requirements

To facilitate implementation of the backstop daily NO_X emissions rates for certain coal-fired units, the secondary emissions limitations for units contributing to assurance level exceedances, and the revised default unit-level allowance allocation procedures, the final rule amends 40 CFR part 75 to establish two sets of additional recordkeeping and reporting requirements. The first set of additional recordkeeping and reporting requirements is specific to the backstop daily emissions rate provisions. Starting January 1, 2024, units listing coal as a fuel in their monitoring plans, serving generators of 100 MW or larger, and equipped with SCR controls on or before the end of the previous control period (except circulating fluidized bed units) will be required to record and report total daily NO_X emissions and total daily heat input, daily average NO_X emissions rate, and daily NO_X emissions exceeding the backstop daily NO_X emissions rate. The units will also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rate for the ozone season and any portion of such cumulative NO_X emissions exceeding 50 tons. Starting January 1, 2030, the same recordkeeping and reporting requirements will apply to all units listing coal as a fuel in their monitoring plans and serving generators of 100 MW or larger (except circulating fluidized bed units), including units not equipped with SCR controls. These data will be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. Implementation of these additional recordkeeping and reporting requirements would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

The second type of additional recordkeeping and reporting requirements applies to units exhausting to common stacks. For these units, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all the units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack. The units then keep records and report hourly and cumulative NO_X mass emissions and in many cases heat input data on a combined basis for all units exhausting to the common stack. With respect to heat input data, but not NO_X mass emissions data, most such units have also been required historically to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically have computed the necessary unit-level hourly heat input values by apportioning the combined hourly heat input values for the common stack in proportion to the individual units' recorded hourly output of electricity or steam. *See generally* 40 CFR 75.72.

In this rulemaking, the provisions governing default unit-level allowance allocations, backstop daily NO_X emissions rates for certain coal-fired units, and secondary emissions limitations for units contributing to assurance level exceedances all require the use of unit-level reported data on NO_X mass emissions (or unit-level NO_X emissions rates computed in part based on unit-level reported data on NO_X mass emissions). To facilitate the implementation of these provisions, the final rule requires all units covered by the Group 3 trading program exhausting to common stacks to record and report unit-level hourly and cumulative NO_X mass emissions data starting January 1, 2024. To obtain the necessary unit-level hourly mass emissions values, the revised regulations rule allow the units to apportion hourly mass emissions values determined at the common stack in proportion to the individual units' recorded hourly heat input. The apportionment procedure is very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Where sources choose to obtain the additional required data values through apportionment, implementation of the additional recordkeeping and reporting requirements will necessitate a one-time update to the units' data acquisition and handling systems but will not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

For most units sharing common stacks, the EPA expects that the reported unit-specific hourly NO_X emissions values computed through the apportionment procedures will reasonably approximate the values that could be obtained through installation and operation of separate monitoring systems for the individual units, because the units exhausting to the common stack would be expected to have similar NO_X emissions rates. However, the EPA also recognizes that at some plants, particularly those where SCR-equipped and non-SCR-equipped coal-fired units share a common stack, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for the SCR-equipped units and correspondingly understate the reported NO_X mass emissions for the non-SCR-equipped units.[362] As proposed, the

[361] The units are listed in Table VI.B.3–1.

[362] The EPA is aware of five plants in the states covered by this rule where SCR-equipped and non-SCR-equipped coal-fired units exhaust to a common stack: Clifty Creek in Indiana; Cooper, Ghent, and Shawnee in Kentucky; and Sammis in Ohio. The owners of the Sammis plant have announced plans to retire the plant in 2023.

final rule leaves in place the existing options under 40 CFR part 75 for plants to upgrade their monitoring equipment to monitor on a unit-specific basis instead of at the common stack. Plant owners may find this option attractive if they believe it would reduce the quantities of reported emissions exceeding the backstop daily emissions rate.

The EPA is finalizing the additional recordkeeping and reporting requirements generally as proposed, with modifications as needed to accommodate the changes in the backstop daily emissions rate provisions from proposal discussed in sections VI.B.1.c.i and VI.B.1.7. No comments were received on the recordkeeping and reporting requirements added to facilitate implementation of the backstop daily emissions rate. Comments on the requirement to report unit-specific NO_X emissions data for units sharing common stacks are addressed in the following paragraphs.

Comment: Some commenters claimed that for plants where SCR-equipped and non-SCR-equipped coal-fired units share common stacks, the rule as proposed would have effectively mandated installation of unit-specific monitoring systems in order to comply with the backstop daily emissions rate provisions. The commenters generally requested that application of the backstop daily rate provisions be delayed for plants with common stacks until all units sharing the stacks were subject to the provisions. Alternatively, they claimed that the EPA should consider the cost of the additional unit-specific monitoring system to be a cost of the rule.

One commenter claimed that the option to install unit-specific monitoring systems for the units sharing a common stack at its plant was not feasible because of a lack of locations in the units' ductwork suitable for installation of the monitoring equipment. Specifically, the commenter claimed that EPA Method 1 requires monitoring equipment to be located at least eight duct diameters downstream and two duct diameters upstream of any flow disturbance and stated that the units had no straight runs of ductwork sufficiently long to meet these criteria.

Response: The EPA's response to comments about the application of backstop rate requirements to units sharing common stacks is in section VI.B.7 of this document. With respect to assertions that the rule effectively mandates installation of unit-specific monitoring systems, the EPA disagrees. Although the EPA pointed out the option in the proposal, anticipating that owners of some units sharing common stacks might find it advantageous to upgrade their monitoring systems, the final rule does not mandate such upgrades and explicitly provides a reporting option that can be used if a plant owner continues to monitor only at the common stack. For example, a plant owner might choose not to upgrade monitoring systems if the owner does not plan to operate the non-SCR-equipped units sharing the stack frequently. Regarding the contention that the cost of additional monitoring systems should be considered a cost of the rule, the EPA notes that the monitoring cost estimates that the Agency regularly develops for 40 CFR part 75 already reflect the conservative assumption that all affected units perform monitoring on a unit-specific basis.

With respect to the comment asserting an inability to install unit-specific monitoring equipment because of a lack of suitable locations, the EPA does not believe the commenter has provided sufficient information to support the assertion. Although the commenter cites the EPA Method 1 location criteria, the CEMS location provisions in 40 CFR part 75 do not reference those location criteria but instead reference the EPA Performance Specification 2 location criteria, which recommend that a CEMS be located at least two duct diameters downstream and a half duct diameter upstream from a point at which a change in pollutant concentration may occur.[363] Thus, while the commenter states that its units do not have straight runs of ductwork ten duct diameters long, the relevant siting criteria actually call for straight runs of ductwork only 2.5 duct diameters long, and the commenter has not provided information indicating that these criteria could not be met. Moreover, even EPA Method 1 does not require monitoring equipment to be located eight duct diameters upstream and two duct diameters downstream of any flow disturbance. While the method recommends those distances as the first option, the method also allows for locations two duct diameters upstream and a half duct diameter upstream from any flow disturbance, as well as other locations if certain performance criteria can be met.[364]

[363] Appendix B to 40 CFR part 60, Performance Specification 2, sec. 8.1.2; *see also* appendix A to 40 CFR part 75, section 1.1.

[364] Appendix A–1 to 40 CFR part 60, Method 1, sec. 11.1.

11. Designated Representative Requirements

As noted in section VI.B.1.a of this document, a core design element of all the CSAPR trading programs is the requirement that each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account. The necessary authorization of a designated representative is certified to the EPA in a certificate of representation.

The existing designated representative provisions in the Group 3 trading program regulations already provide that the EPA will interpret references to the Group 2 trading program in certain documents—including a certificate of representation as well as a notice of delegation to an agent or an application for a general account—as if the documents referenced the Group 3 trading program instead of the Group 2 trading program. For these reasons, sources that have participated in the Group 2 trading program and that are transitioning to the Group 3 trading program under this rule will not need to submit any new forms as part of the transition, because previously submitted forms will be valid for purposes of the Group 3 trading program.

For a source that is newly affected under the Group 3 trading program and that is not currently affected under the Group 2 trading program, a designated representative who has been duly authorized by the source's owners and operators must submit a new or updated certificate of representation to the EPA. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until a certificate of representation has been submitted for the source. If a source is also affected under other CSAPR trading programs or the Acid Rain Program, the same individual must be the source's designated representative for purposes of all the programs.

The EPA did not propose and is not finalizing any changes to the designated representative requirements. The EPA received no comments on the provisions of the proposal relating to these requirements.

12. Transitional Provisions

This section discusses several provisions that the EPA will implement to address the transition of sources into the Group 3 trading program as revised. The purposes of the transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: first, addressing the likelihood that the effective date of this rule will fall after the starting date of the first affected ozone season (which in this case is, May 1, 2023); second, establishing an appropriately-sized initial allowance bank through the conversion of previously banked allowances; and third, preserving the intended stringency of the Group 2 trading program for the sources that will continue to be subject to that program.[365] However, the sources that will be participants in the revised Group 3 trading program under this rule are transitioning from several different starting points—with some sources already in the existing Group 3 trading program, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. The EPA is therefore finalizing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points.

a. Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023

The EPA expects that the effective date of this rule will fall after the start of the Group 3 trading program's 2023 control period on May 1, 2023, because the effective date of the rule will be 60 days after the date of the final rule's publication in the **Federal Register**. The EPA is addressing this circumstance by determining the amounts of emissions budgets and unit-level allowance allocations on a full-season basis in the rulemaking and by also including provisions in the revised regulations to prorate the full-season amounts as needed to ensure that no sources become subject to new or more stringent regulatory requirements before the final rule's effective date.[366] Variability limits, assurance levels, and unit-level allocations for 2023 will all be computed using the appropriately prorated emissions budgets amounts.[367]

As discussed in section VI.B.2 of this document, in the case of the three states (and Indian country within the states' borders) whose sources do not currently participate in either the Group 2 trading program or the Group 3 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the later of May 1, 2023, or the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, and were therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. Assuming that the final rule becomes effective after May 1, 2023, as expected, the EPA will determine prorated emissions budgets for the 2023 control period by multiplying each full-season emissions budget by the number of days from the rule's effective date through September 30, 2023, dividing by 153 days, and rounding to the nearest allowance. The prorated variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season (*i.e.,* May 1, 2023 through September 30, 2023) exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance, yielding prorated assurance levels that equal a minimum of 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA will apply the unit-level allocation procedure described in section VI.B.9 to the prorated budgets. All calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the rule's effective date. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 3 trading program—Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—the sources will continue to participate in the Group 3 trading program for the 2023 control period, subject to prorating procedures designed to ensure that the changes in 2023 emissions budgets and assurance levels will not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, but the EPA has also retained in the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. The EPA has added a provision to the regulations indicating that the emissions budgets promulgated in the Revised CSAPR Update will apply on a prorated basis for the portion of the 2023 control period before the final rule's effective date and the emissions budgets established in this rulemaking will apply on a prorated basis for the portion of the 2023 control period on and after the final rule's effective date. Under this provision, the EPA will determine a blended emissions budget for each state for the 2023 control period, computed as the sum of the appropriately prorated amounts of the state's previous and revised emissions budgets. (For example, if the final rule becomes effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget will equal the sum of 10/153 times the previous emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance,

[365] As discussed in section VI.B.1.d, the EPA is not creating a "safety valve" mechanism in this rule analogous to the voluntary supplemental allowance conversion mechanism established under the Revised CSAPR Update, but intends in the near future to propose and take comment on potential amendments to the Group 3 trading program that would add an auction mechanism to the regulations for the purpose of further increasing allowance market liquidity in conjunction with other appropriate changes to ensure program stringency is maintained. While these changes may provide an additional measure of assurance to the market that allowances will be available for compliance to a degree consistent with the Step 3 emissions control stringency, the EPA does not anticipate that market liquidity concerns pose a challenge to the feasibility of sources to comply with the Group 3 trading program as finalized in this action.

[366] As discussed in sections VI.B.7 and VI.B.8, the revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, will not take effect until the 2024 control period or later.

[367] The EPA notes that transitional provisions similar to the prorating provisions being finalized in this rule were finalized and implemented without issue under the Revised CSAPR Update.

yielding blended assurance levels that equal a minimum of 121 percent of the blended emissions budgets. Unit-level allocations will be determined by applying the allocation procedure described in section VI.B.9 to the blended budgets. Again, all calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the effective date of this rule. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the rule's effective date, as discussed in section VI.B.2 of this document, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program will not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states mirror the procedures for the states currently in the Group 3 trading program, except that because no emissions budgets currently appear in the Group 3 trading program regulations for the states that are currently covered by the Group 2 trading program, the EPA has added two sets of emissions budgets for these states to the Group 3 trading program regulations: first, the states' emissions budgets for the 2023 control period that currently appear in the Group 2 trading program regulations, which are being included in the revised Group 3 trading program regulations to represent the states' emissions budgets for the portion of the 2023 control period before the rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which are being included in the revised Group 3 trading program regulations to represent the state's emissions budgets for the portion of the 2023 control period on and after the rule's effective date. The procedures and timing for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, as well as the timing for the recordation of unit-level allocations, are the same as for the states currently in the Group 3 trading program.

Beginning administrative implementation of the Group 3 trading program starting on May 1, 2023, for sources currently in the Group 2 trading program imposes no new or different requirements on these sources. It would serve the public interest and greatly aid in administrative efficiency for most elements of the Group 3 trading program—specifically, all elements of the trading program other than the elements designed to establish more stringent emissions limitations for the sources coming from the Group 2 trading program—to apply to the sources starting on May 1, 2023. This is how the EPA handled the earlier transition of twelve states from the Group 2 to the Group 3 trading program in the Revised CSAPR Update, which was accomplished successfully and without incident. *See* 86 FR 23133–34. This approach would facilitate implementation of the Group 3 trading program in an orderly manner for the entire 2023 ozone season and reduce compliance burdens and potential confusion. Each of the CSAPR trading programs for ozone season NO_X is designed to be implemented over an entire ozone season. Implementing the transition from the Group 2 trading program to the Group 3 trading program in a manner that required the covered sources to participate in the Group 2 trading program for part of the 2023 ozone season and the Group 3 trading program for the remainder of that ozone season would be complex and burdensome for sources. Attempting to address the issue by splitting the Group 2 and Group 3 requirements for these sources into separate years is not a viable approach, because the EPA has no legal basis for releasing the transitioning Group 2 sources from the emissions reduction requirements found to be necessary in the CSAPR Update for a portion of the 2023 ozone season, and the EPA similarly has no legal basis for deferring implementation of the 2023 emissions reduction requirements found to be necessary under this rule for the transitioning Group 2 sources until 2024. Moreover, the requirements of the current Group 2 trading program and the revised Group 3 trading program for the 2023 control period are substantively identical as to almost all provisions, such that with respect to those provisions, a source will not need to alter its operations in any manner or face different compliance obligations as a consequence of a transition from the Group 2 trading program to the Group 3 trading program. Thus, the EPA believes that no substantive concerns regarding retroactivity arise from transitioning the sources currently in the Group 2 trading program to the Group 3 trading program starting on May 1, 2023, as long as those aspects of the revised Group 3 trading program for the 2023 control period that *do* meaningfully differ from the analogous aspects of the Group 2 trading program—that is, the relative stringencies of the two trading programs, as reflected in the emissions budgets and associated assurance levels—are applied only as of the effective date of the final rule.

In all respects other than prorating the emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, with respect to the sources currently participating in the Group 2 trading program or the Group 3 trading program, the EPA will implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions will be monitored and reported for the entire 2023 ozone season (*i.e.,* May 1, 2023, through September 30, 2023), and as of the allowance transfer deadline for the 2023 control period (*i.e.,* June 1, 2024) each source will be required to hold in its compliance account vintage-year 2023 Group 3 allowances not less than the source's emissions of NO_X during the entire 2023 ozone season. Any efforts undertaken by one of these sources to reduce its emissions during the portion of the 2023 ozone season before the effective date of the rule will aid the source's compliance by reducing the amount of Group 3 allowances that the source would need to hold in its compliance account as of the allowance transfer deadline, increasing the range of options available to the source for meeting its compliance obligations under the revised Group 3 trading program.

In the case of the sources in the three states that do not currently participate in the Group 2 trading program or the Group 3 trading program, the 2023 control period will begin on the effective date of the rule, and because the effective date of the rule is expected to fall after May 1, 2023, the 2023 control period for the sources in these states will be shorter than the 153-day length of the 2023 control period for the sources in the remaining states. However, the EPA similarly will implement the revised Group 3 trading program for the sources in these states in a uniform manner for the entire shorter control period.

The prorating provisions are being finalized as proposed. The EPA received no comments on the portion of the proposal discussing these provisions.

b. Creation of Additional Group 3 Allowance Bank for 2023 Control Period

In the CSAPR Update, where the EPA established the Group 2 trading program and transitioned over 95 percent of the sources that had been participating in what is now the CSAPR NO_X Ozone Season Group 1 Trading Program (the "Group 1 trading program") to the new program, the EPA determined that it was reasonable to establish an initial bank of allowances for the Group 2 trading program by converting almost all allowances banked under the Group 1 trading program at a conversion ratio determined by a formula. In the Revised CSAPR Update, where the EPA established the Group 3 trading program and transitioned approximately 55 percent of the sources that had been participating in the Group 2 trading program to the new program, the EPA similarly determined that it was reasonable to provide for an initial bank of allowances for the Group 3 trading program by converting allowances banked under the Group 2 trading program at a conversion ratio determined by a formula, using a conversion procedure that was modified to leave much of the Group 2 allowance bank available for use by the approximately 45 percent of sources then in the Group 2 trading program that would remain in that program. Any conversion of banked allowances from a previous trading program for use in a new trading program must ensure that implementation of the new trading program will result in NO_X emissions reductions sufficient to address significant contribution by all states that would be participating in the new trading program, while also providing industry certainty (and obtaining an environmental benefit) through continued recognition of the value of saving allowances through early reductions in emissions. The EPA's approach to balancing these concerns in the CSAPR Update through the conversion of banked allowances from the Group 1 trading program to the Group 2 trading program was upheld in *Wisconsin* v. *EPA,* 938 F.3d at 321.

Under this final rule, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA will carry out a further conversion of allowances banked for control periods before 2023 under the Group 2 trading program into allowances usable in the Group 3 trading program in control periods in 2023 and later years. Because the EPA is transitioning over 80 percent of the remaining sources in the Group 2 trading program to the Group 3 trading program—much closer to the situation in the CSAPR Update than the situation in the Revised CSAPR Update—in this rule the EPA is applying a conversion procedure similar to the procedure followed in the CSAPR Update. Under the conversion procedure in this rule, the EPA has not set a predetermined conversion ratio in the regulations (as was done in the Revised CSAPR Update) but instead has established provisions identifying the target amount of new Group 3 allowances that will be created and defining the types of accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances (as was done in the CSAPR Update). The conversion date will be carried out by September 18, 2023, which is expected to be approximately 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and approximately ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio will be determined as of the conversion date and will be the ratio of the total amount of Group 2 allowances held in the identified types of accounts prior to the conversion to the total amount of Group 3 allowances being created.

With respect to the numerator of the conversion ratio—that is, the total amount of Group 2 allowances being converted—the EPA has defined the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that will remain in the Group 2 trading program, consistent with the approach taken in the CSAPR Update.[368] Thus, the accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances will include (1) the facility accounts of all sources in the states transitioning from the Group 2 trading program to the Group 3 trading program, (2) the facility accounts of all sources in the states already participating in the Group 3 trading program, (3) the facility accounts of all sources in any other states not covered by the Group 2 trading program that happen to hold Group 2 allowances as of the conversion date, and (4) all general accounts (that is, accounts that are not facility accounts, including other accounts controlled by source owners as well as accounts controlled by non-source entities such as allowance brokers). Creating the new Group 3 allowances through conversion of previously banked Group 2 allowances will also help preserve the stringency of the Group 2 trading program for the states that remain covered by that trading program at levels consistent with the stringency found to be appropriate to address those states' good neighbor obligations with respect to the 2008 ozone NAAQS in the CSAPR Update.

With respect to the denominator of the conversion ratio—that is, the target amount of Group 3 allowances that will be created in the conversion process—the EPA has followed the same approach for setting the target amount that was used in the Revised CSAPR Update for creation of the initial Group 3 allowance bank. Specifically, the target amount of Group 3 allowances to be created in this rule will be computed as the sum of the minimum 21 percent variability limits for the 2024 control period[369] established for the ten states being added to the Group 3 trading program, prorated to reflect the portion of the 2023 control period occurring on and after the effective date of the final rule. Based on the amounts of the state emissions budgets and variability limits, the full-season target amount for the conversion would be 23,094 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa, Kansas, and Tennessee exceeding the quantity of allowances likely to be needed for 2022 compliance is approximately 149,386 allowances. Thus, if the quantities of banked Group 2 allowances held in the accounts being included in the conversion do not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 6.5-to-1, meaning that one Group 3 allowance would be created for every 6.5 Group 2 allowances deducted in the conversion process.[370]

As noted in section VI.B.12.a of this document, the EPA expects that the effective date of this rule will occur after

[368] The states whose sources will continue to participate in the Group 2 trading program for the 2023 control period will be Iowa, Kansas, and Tennessee.

[369] Similar to the approach taken in the Revised CSAPR Update, because emissions reductions from some of the emissions controls that EPA has identified as appropriate to use in setting budgets are first reflected in the 2024 state budgets rather than the 2023 state budgets, the EPA is basing the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[370] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

the start of the 2023 ozone season, and prorating provisions are being promulgated in this rule to ensure that the increased stringency of this rule's state budgets and state assurance levels (*i.e.,* the sums of the budgets and variability limits) will take effect only after the rule's effective date. Consistent with these other procedures, the EPA will similarly prorate the bank target amount used in the conversion process. For example, if the effective date of the final rule is the eleventh day of the 153-day 2023 ozone season, the full-season initial bank target amount of 23,094 allowances would be prorated to an initial bank target amount of 21,585 allowances.[371] The EPA notes that prorating the bank amount in this manner will not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources will receive for the portion of the 2023 ozone season before the rule's effective date will be based on the trading program budgets for the 2023 control period that were in effect before this rulemaking. These trading program budgets exceed the sources' collective 2022 emissions by approximately 29,789 tons, indicating potentially surplus allowances roughly 1.3 times the full-season bank conversion target amount of 23,094 allowances. Thus, although the prorating procedure will reduce the amount of Group 3 allowances that would be available to sources in the form of an initial bank, the reduction in the quantity of these allowances will be more than offset by the quantities of Group 3 allowances that will be allocated in excess of sources' recent historical emissions levels for the portion of the ozone season before the final rule's effective date.

As in the CSAPR Update and the Revised CSAPR Update, the EPA's overall objective in establishing the target amount for the allowance conversion is to achieve a total target amount for the bank at a level high enough to accommodate year-to-year variability in operations and emissions, as reflected in states' variability limits, but not high enough to allow sources collectively to plan to emit in excess of the collective state budgets. The EPA believes that a well-established trading program should be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VI.B.6 of this document with respect to the bank recalibration process that will begin with the 2024 control period. However, the EPA also believes there are several compelling reasons in this instance to use a bank target higher than the minimum practicable level.

First, making an allowance bank available for use in the 2023 control period that is somewhat higher than the minimum practicable level will help to address concerns that might otherwise arise regarding the transition to a new set of compliance requirements, for some sources, and the transition to compliance requirements based on revised emissions budgets different from the emissions budgets that the sources had reason to anticipate under previous rulemakings, for the remaining sources. Although the EPA is confident that the emissions budgets being established in this rulemaking for the 2023 control period are readily achievable, the EPA also believes that the existence of a somewhat larger allowance bank at this transition point will promote sources' confidence in their ability to meet their 2023 compliance obligations in general and in a liquid allowance market in particular. Second, because the large majority of the remaining Group 2 allowances that will be converted to Group 3 allowances in this rulemaking are held by the sources currently in the Group 2 trading program, while the large majority of the initial bank of Group 3 allowances previously created in the conversion under the Revised CSAPR Update are held by the sources already in the Group 3 trading program, basing the conversion in this rulemaking on a target bank amount set in the same manner as the target bank amount used in the Revised CSAPR Update is expected to result in a less concentrated distribution of holdings of banked Group 3 allowances following the conversion than would be the case if a more stringent target bank amount were used under this rulemaking than was used in the Revised CSAPR Update. A lower concentration of holdings of banked Group 3 allowances would generally be expected to help ensure allowance market liquidity. Third, the EPA considers it equitable to treat the sources in the states transitioning from the Group 2 trading program to the Group 3 trading program in this rulemaking roughly similarly to the sources in the states that transitioned between the same two trading programs in the Revised CSAPR Update with respect to the benefit they would receive under the Group 3 trading program for any efforts they may have made to make emissions reductions under the Group 2 trading program beyond the minimum efforts that were required to comply with the emissions budgets under that program. Finally, to the extent that the conversion results in a larger bank of allowances remaining after the 2023 control period than is considered necessary to sustain a well-functioning trading program in subsequent control periods, the excess will be removed from the program in the bank recalibration process that will be implemented starting with the 2024 control period and therefore will not weaken sources' incentives to control emissions on a permanent basis.

The rule's provisions relating to the creation of an incremental Group 3 allowance bank are being finalized as proposed. Comments on the creation of the incremental allowance bank are discussed in section 5 of the *RTC.*

c. Recall of Group 2 Allowances Allocated for Control Periods After 2022

To maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program, the EPA is recalling CSAPR NO_X Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023–2024 CSAPR NO_X Ozone Season Group 2 allowances previously allocated to sources in states and areas of Indian country transitioning to the Group 3 trading program and recorded in the sources' compliance accounts. The recall provisions apply to all sources in jurisdictions newly added to the Group 3 trading program in whose compliance accounts CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2023 or 2024 were recorded, including sources where some or all units have permanently retired or where the previously recorded 2023–2024 allowances have been transferred out of the compliance account. The recall provisions provide a flexible compliance schedule intended to accommodate any sources that have already transferred the previously recorded 2023–2024 allowances out of their compliance accounts and allow Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the recall provisions include specifications for how the recall provisions apply in instances where a source and its allowances have been transferred to different parties and for the procedures that the EPA will follow to implement the recall.

Under the Group 2 trading program regulations, each Group 2 allowance is a "limited authorization to emit one ton of NO_X during the control period in one year," where the relevant limitations include the EPA Administrator's

[371] 23,094 × (153 10) ÷ 153 = 21,585.

authority "to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act." 40 CFR 97.806(c)(6)(ii). The Administrator is determining that, to effectively implement the Group 2 trading program as a compliance mechanism through which states not subject to the Group 3 trading program may continue to meet their obligations under CAA section 110(a)(2)(D)(i)(I) with regard to the 2008 ozone NAAQS, it is necessary to limit the use of Group 2 allowances equivalent in quantity and usability to all Group 2 allowances previously allocated for the 2023–2024 control periods and recorded in the compliance accounts of sources in the newly added Group 3 jurisdictions. The Group 2 allowances that have already been allocated to sources in the newly added Group 3 states for the 2023–2024 control periods and recorded in the sources' compliance accounts represent the substantial majority of the total remaining quantity of Group 2 allowances that have been allocated and recorded for the 2023–2024 control periods and that were not already made subject to recall when other jurisdictions were transferred from the Group 2 trading program to the Group 3 trading program in the Revised CSAPR Update. Because allowances can be freely traded, if the use of the 2023–2024 Group 2 allowances previously recorded in newly added Group 3 sources' compliance accounts (or equivalent Group 2 allowances) were not limited, the effect would be the same as if the EPA had issued to sources in the states that will remain covered by the Group 2 trading program a quantity of allowances available for compliance under the 2023–2024 control periods many times the levels that the EPA determined to be appropriate emissions budgets for these states in the CSAPR Update. Through the use of banked allowances, the excess Group 2 allowances would affect compliance under the Group 2 trading program in control periods after 2024 as well. Continued implementation of the Group 2 trading program at levels of stringency consistent with the levels contemplated under the CSAPR Update therefore requires that the EPA limit the use of the excess allowances, as the EPA is doing through the recall provisions.

In this rule, the EPA is implementing limitations on the use of the excess 2023–2024 Group 2 allowances through requirements to surrender, for each 2023–2024 Group 2 allowance recorded in a newly added Group 3 source's compliance account, one Group 2 allowance of equivalent usability under the Group 2 trading program. The surrender requirements apply to the owners and operators of the Group 3 sources in whose compliance account the excess 2023–2024 Group 2 allowances were initially recorded. In general, each source's current owners and operators are required to comply with the surrender requirements for the source by ensuring that sufficient allowances to complete the deductions are available in the source's compliance account by one of two possible deadlines discussed later in this section. However, an exception is provided if a source's current owners and operators obtained ownership and operational control of the source in a transaction that did not include rights to direct the use and transfer of some or all of the 2023–2024 Group 2 allowances allocated and recorded (either before or after that transaction) in the source's compliance account. The rule provides that in such a circumstance, with respect to the 2023–2024 Group 2 allowances for which rights were not included in the transaction, the surrender requirements apply to the most recent former owners and operators of the source before any such transactions occurred. Because in this situation a source's former owners and operators might lack the ability to access the source's compliance account for purposes of complying with the surrender requirements, the former owners and operators would instead be allowed to meet the surrender requirements with Group 2 allowances held in a general account.[372]

To provide as much flexibility as possible consistent with the need to limit the use of the excess Group 2 allowances, for each 2023–2024 Group 2 allowance recorded in a Group 3 source's compliance account, the EPA will accept the surrender of either the same specific 2023–2024 Group 2 allowance or any other Group 2 allowance with equivalent (or greater) usability under the Group 2 trading program. Thus, a surrender requirement with regard to a Group 2 allowance allocated for the 2023 control period could be met through the surrender of any Group 2 allowance allocated for the 2023 control period or the control period in any earlier year—in other words, any 2017–2023 Group 2 allowance.[373] Similarly, the surrender requirement with regard to a 2024 Group 2 allowance could be met through the surrender of any 2017–2024 Group 2 allowance.

Owners and operators subject to the surrender requirements can choose from two possible deadlines for meeting the requirements. The optional first deadline will be 15 days after the effective date of this rule.[374] As soon as practicable or after this date, the EPA will make a first attempt to complete the deductions of Group 2 allowances required for each Group 3 source from the source's compliance account. The EPA will deduct Group 2 allowances first to address any surrender requirements for the 2023 control period and then to address any surrender requirements for the 2024 control period. When deducting Group 2 allowances to address the surrender requirements for each control period, EPA will first deduct allowances allocated for that control period and then will deduct allowances allocated for each successively earlier control period. This order of deductions is intended to ensure that whatever Group 2 allowances are available in the account are applied to the surrender requirements in a manner that both maximizes the extent to which all of the source's surrender requirements will be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions will be the earliest allocated, and therefore most useful, Group 2 allowances possible. Among the Group 2 allowances allocated for a given control period, The EPA will first deduct allowances that were initially recorded in that account, in the order of recordation, and will then deduct allowances that were transferred into that account after having been initially recorded in some other account, in the order of recordation.

Following the first attempt to deduct Group 2 allowances to address Group 3 sources' surrender requirements, the

[372] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the rule to address the theoretical possibility of such a situation.

[373] The first control period for the Group 2 trading program was in 2017.

[374] As discussed later in this section and in section VI.B.9.b, the EPA has conditioned recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the recall requirements for Group 2 allowances. The purpose of providing an optional first deadline for the recall provisions 15 days after a final rule's effective is to ensure that sources have an early opportunity to comply with the recall provisions to be eligible to have allocations of Group 3 allowances recorded in their accounts 30 days after the final rule's effective date. Because the vast majority of sources subject to the recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources will easily be able to comply with the optional first recall deadline.

EPA will send a notification to the designated representative for each such source (as well as any alternate designated representative) indicating whether all required deductions were completed and, if not, the additional amounts of Group 2 allowances usable in the 2023 or 2024 control periods that must be held in the appropriate account by the second surrender deadline of September 15, 2023. Each notification will be sent to the email addresses most recently provided to the EPA for the recipients and will include information on how to contact the EPA with any questions. The EPA has provided that no allocations of Group 3 allowances will be recorded in a source's compliance account until all the source's surrender requirements with regard to 2023–2024 Group 2 allowances have been met. For this reason, the principal consequence to a source of failure to fully comply with the surrender requirements by 15 days after the effective date of this rule will be that any Group 3 allowances allocated to the units at the source for the 2023 and 2024 control periods that would otherwise have been recorded in the source's compliance account by 30 days after the effective date of a final rule will not be recorded as of that recordation date.

If all surrender requirements of 2023–2024 Group 2 allowances for a source have not been met in EPA's first attempt, the EPA will make a second attempt to complete the required deductions from the source's compliance account (or from a specified general account, in the limited circumstance noted previously) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted will be the same as described previously for the first attempt.

If the second attempt to deduct Group 2 allowances to meet the surrender requirements through deductions from the source's compliance account (or from a specified general account) is unsuccessful for a given source, as soon as practicable on or after November 15, 2023, to the extent necessary to address the unsatisfied surrender requirements for the source, the EPA will deduct the 2023–2024 Group 2 allowances that were initially recorded in the source's compliance account from whatever accounts the allowances are held in as of the date of the deduction, except for any allowances where, as of April 30, 2022, no person with an ownership interest in the allowances was an owner or operator of the source, was a direct or indirect parent or subsidiary of an owner or operator of the source, or was directly or indirectly under common ownership with an owner or operator of the source.[375] Before making any deduction under this provision, the EPA will send a notification to the authorized account representative for the account in which the allowance is held and will provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision does not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision will not be invoked in the case of any allowance that was transferred to an independent party in an arms-length transaction before EPA's intent to recall 2023–2024 Group 2 allowances became widely known. The provision would apply only to a Group 2 allowance that, as of April 30, 2022, was still controlled either by the owners and operators of the source in whose compliance account it was initially recorded or by an entity affiliated with such an owner or operator. The EPA believes that by April 30, 2022, all market participants had ample opportunity to become informed of the proposed rule provisions to recall 2023–2024 Group 2 allowances recorded in Group 3 sources' compliance accounts, particularly since the EPA implemented a closely analogous recall of Group 2 allowances in the Revised CSAPR Update.[376]

The final revised regulations provide that failure of a source's owners and operators to comply with the surrender requirements will be subject to possible enforcement as a violation of the CAA, with each allowance and each day of the control period constituting a separate violation.

To eliminate any possible uncertainty regarding the amounts of Group 2 allowances allocated for the 2023–2024 control periods (or earlier control periods) that the owners and operators of each Group 3 source are required to surrender under the recall provisions, the EPA has prepared a list of the sources in the additional Group 3 states and areas of Indian country in whose compliance accounts allocations of 2023–2024 Group 2 allowances were recorded, with the amounts of the allocations recorded in each such compliance account for the 2023 and 2024 control periods. An additional list shows, for each newly added Group 3 source, the specific Group 2 allowances (batched by serial number) allocated for each control period and recorded in the source's compliance account and indicates whether, as of April 30, 2022, that batch of allowances was held in the source's compliance account, in an account believed to be partially or fully controlled by a related party (*i.e.,* an owner or operator of the source or an affiliate of an owner or operator of the source), or in an account believed to be fully controlled by independent parties. The lists are in a spreadsheet titled, "Recall of Additional CSAPR NO_X Ozone Season Group 2 Allowances," available in the docket for this rule. After the first and second surrender deadlines, the EPA intends to update the lists to indicate for each Group 3 source whether the surrender requirements for the source under the recall provisions have been fully satisfied. The EPA will post the updated lists on a publicly accessible website to ensure that all market participants have the ability to determine which specific 2023–2024 Group 2 allowances initially recorded in any given Group 3 source's compliance account do or do not remain subject to potential deduction to address the source's surrender requirements under the recall provisions.

The recall provisions have been finalized without change from the proposal. The EPA received no comments on the proposed provisions.

13. Conforming Revisions to Regulations for Other CSAPR Trading Programs

As noted in section VI.B.1.a of this document, in addition to the Group 3 trading program, EPA currently administers five other CSAPR trading programs, all of which have provisions that in most respects parallel the provisions of the Group 3 trading program.[377] In this rulemaking, in addition to the revisions to the Group 3 trading program, the EPA is finalizing a set of conforming revisions that concern how various areas of Indian country are

[375] The provision under which the EPA will not deduct Group 2 allowances transferred to unrelated parties before April 30, 2022 from the transferees' accounts does not relieve the source to which the Group 2 allowances were originally allocated from the obligation to comply with the recall requirements. Specifically, the source would be required to comply with the recall requirements by obtaining and surrendering other Group 2 allowances.

[376] Even before publication of the proposed rule, the EPA posted information on its websites to notify market participants that a pending rulemaking could have consequences for the value and usability of Group 2 allowances. The posted locations included the electronic portal that authorized account representatives use to enter allowance transfers for recordation by the EPA in the Allowance Management System. Additionally, the EPA emailed a notice identifying the possibility of such consequences to the representatives for all Allowance Management System accounts.

[377] The regulations for the Group 3 Trading Program are at 40 CFR part 97, subpart GGGGG. The regulations for the other five CSAPR trading programs are at 40 CFR part 97, subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE.

treated for purposes of the allowance allocation provisions of the regulations for all the CSAPR trading programs.[378]

As discussed in section VI.B.9.a of this document, to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area, the EPA is revising the allowance allocation provisions in the Group 3 trading program regulations so that, instead of distinguishing between the sets of units within a given state's borders that either are not or are in Indian country, the revised regulations distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. For the same reasons stated in section VI.B.9.a of this document for the Group 3 trading program, the EPA is revising the allowance allocation provisions in the regulations for all the other CSAPR trading programs establishing the same substantive distinction among the sets of units within each state's borders. The specific regulatory provisions that are affected are identified in section IX.D of this document. The EPA is unaware of any currently operating units that would be affected by this revision to the regulations for the other CSAPR trading programs.

The conforming revisions to the regulations for the other CSAPR trading programs concerning Indian country are being finalized as proposed with no changes. The EPA received no comments on this portion of the proposal.

C. Regulatory Requirements for Stationary Industrial Sources

The EPA is finalizing FIPs with requirements for certain non-EGU industry sources for 20 of the states covered in this final rule. See section II.B of this document for the list of states. The FIPs include new emissions limitations for units in nine non-EGU industries that the EPA finds (as discussed in sections IV and V of this final rule) are significantly contributing to nonattainment or interfering with maintenance in other states. The emissions control requirements of these FIPs for non-EGU sources apply only during the ozone season (May through September) each year, beginning in 2026.

To achieve the necessary non-EGU emissions reductions for these 20 states, the EPA is finalizing the proposed emissions limitations with some adjustments as a result of information received during the public comment period. The final emissions limits apply to the most impactful types of units in the relevant industries and are achievable with the control technologies identified in this preamble and further discussed in the Final Non-EGU Sectors TSD. The non-EGU regulatory requirements unique to each industry that EPA is finalizing after considering public comments are discussed in sections VI.C.1 through VI.C.6 of this document.

These final FIP requirements apply to both new and existing emissions units. The non-EGU emissions limits and compliance requirements will apply in all 20 states (and, as discussed in section III.C.2 of this document, in areas of Indian country within the borders of those states), even if some of those states do not currently have emissions units in a particular source category. This approach is consistent with the approach that the EPA proposed, and the EPA did not receive any comments specifically objecting to our proposal to regulate new units. This approach will ensure that all new sources constructed in any of the 20 states will be subject to the same good neighbor requirements that apply to existing units under this final rule. This will also avoid creating incentives to move production from an existing non-EGU source to a new non-EGU source of the same type but lacking the relevant emissions control requirements either within a linked state or in another linked state.

Comment: The EPA received several comments regarding the proposed approach of establishing unit-specific emissions limitations for non-EGUs instead of an emissions trading program. Some commenters suggested that a trading program for non-EGUs could provide for operational flexibility and that EPA should allow sources to work with regulatory authorities to develop a trading program. Other commenters generally supported EPA's proposed approach and the decision to not include non-EGUs in an emissions trading program, because the EPA would not need to require sources to unnecessarily install CEMS. Commenters from several states and industry groups generally supported other monitoring options over CEMS, such as parametric monitoring, performance testing, and predictive emissions monitoring systems (PEMS). Additional commenters voiced concern with the expense and burden of continuous parametric monitoring and semi-annual performance tests. Specifically, commenters explained that semi-annual testing should not be required when the emissions limits only apply during the ozone season. Commenters also noted that many non-EGU boilers have recently been relieved from meeting the CEMS requirements under the 1998 NO_X SIP Call and that implementing CEMS on many of the non-EGU sources would be difficult and unnecessary.

Response: The EPA is finalizing a unit-specific approach with rate-based emissions limitations set on a uniform basis for the different segments of non-EGU emissions units using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. In response to public comments, the EPA has adjusted these requirements as necessary to ensure that the emissions control requirements are achievable while ensuring that the FIPs achieve the necessary emissions reductions from the covered units to eliminate significant contribution to nonattainment and interference with maintenance as discussed in section V of this document. The EPA has concluded that a unit-specific approach is more appropriate for non-EGUs at this time than implementing a trading program and requiring all units to implement rigorous part 75 monitoring and reporting requirements. As explained in the proposal, to be considered for a trading program, non-EGU sources would have to comply with requirements for monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all previous trading programs. Monitoring and reporting under part 75 include CEMS (or an approved alternative method), rigorous initial certification testing, and periodic quality assurance testing thereafter, such as relative accuracy test audits and daily calibrations. Consistent and accurate measurement of emissions is necessary to ensure that each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. *See* 75 FR 45325 (August 2, 2010). Moreover, these monitoring requirements generally would need to be in place for at least

[378] Additional conforming revisions concerning the schedules for the EPA to record allowance allocations in source's compliance accounts and for states to submit state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

one full ozone season to establish baseline data before it would be appropriate to rely on a trading program as the mechanism to achieve the required emissions reductions. Many industry and state commenters provided information confirming that many non-EGU units subject to this rulemaking do not currently utilize CEMS and specifically requested that EPA avoid requiring CEMS for all non-EGU industries. The EPA generally agrees that CEMS is not necessary for all non-EGU industries under the approach of this final rule and is finalizing other continuous monitoring, recordkeeping, and reporting requirements, as appropriate, that are specific to each non-EGU industry. The EPA has determined that establishing unit-specific emissions limitations for non-EGUs is a preferable approach in part because it avoids the rigorous monitoring requirements that would be applied to non-EGUs for the first time under a trading program.

Furthermore, to address commenters' concerns regarding non-EGU requirements for performance testing on a semi-annual basis, the EPA has also reduced the frequency of all required performance testing for non-EGU sources to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to demonstrate continuous compliance during the ozone season. The EPA also agrees with commenters that the annual testing requirements need not occur during the ozone season.

In addition, the EPA is modifying the applicability criteria and other regulatory requirements in response to public comments to provide certain compliance flexibilities for non-EGU industries where appropriate. As discussed further in section V.C.1 of this document, the EPA is modifying the requirements for Pipeline Transportation of Natural Gas by finalizing an exemption for emergency engines and allowing any owner or operator of an affected unit to propose a "Facility-Wide Averaging Plan" that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. Further, as discussed in section VI.C.5 of this document, the EPA is finalizing a low-use exemption for non-EGU boilers that operates less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. These final rule provisions require controls on the most impactful non-EGU industrial sources while providing the flexibility needed to accommodate unique circumstances on a case-by-case basis.

Comment: Commenters from several non-EGU industries and states raised general concerns regarding the ability for all sources to comply with the proposed emissions limits. Some commenters suggested that the EPA allow for case-by-case limits where necessary, similar to case-by-case RACT determinations. Specifically, commenters operating boilers, furnaces, and MWCs provided general explanations of how some units might not be able to meet the proposed emissions limits and requested that EPA provide for compliance flexibility where a source can demonstrate technical and economical infeasibility.

Response: As explained more in sections VI.C.1 through VI.C.6, the EPA has made several adjustments to the proposed applicability criteria, emissions limits, and compliance requirements in response to public comments and to reduce the costs of compliance with the final rule. For Pipeline Transportation and Natural Gas, the EPA is finalizing emissions averaging provisions and exemptions for emergency engines to allow facilities to avoid installing controls on units with lower actual emissions where the installation of controls would be less cost effective compared to higher-emitting units. For Cement and Concrete Product Manufacturing, the EPA has removed the daily source cap that would have resulted in an artificially restrictive NO_X emissions limit for affected cement kilns that have operated at lower levels due to the COVID–19 pandemic. For Iron and Steel and Ferroalloy Manufacturing, the EPA is finalizing a "test-and-set" requirement for reheat furnaces that will require the installation of low-NO_X burners or equivalent technology. The EPA has addressed the economic concerns raised by commenters regarding installation of controls at Iron and Steel facilities by not finalizing the other ten proposed emissions limits that were intended to require the installation of SCR at these facilities. For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions. For boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel Industry, the EPA is finalizing a low-use exemption to eliminate the need to install controls on boilers that would have resulted in relatively small reductions in emissions. Finally, the EPA has modified the monitoring and recordkeeping requirements for all non-EGU industries where possible to reduce the testing frequency to once a year and to provide for alternative monitoring protocols where appropriate, which should further reduce the costs of compliance on non-EGU sources. With these modifications to the final rule in response to comments, the non-EGU sources subject to this rule should be able to meet the applicable control requirements established in this final rule.

The EPA also recognizes, however, that there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship. To address these limited circumstances, the EPA is finalizing a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship. The EPA has modeled the case-by-case emissions limit mechanism on case-by-case RACT requirements and certain facility-specific emissions limits under 40 CFR part 60 identified by commenters.[379] The owner or operator of a source seeking a case-by-case emissions limit must submit a request meeting specific requirements to the EPA by August 5, 2024, one year after the effective date of this final rule. The applicable emissions limits established in this final rule remain in effect until the EPA approves a source's request for a case-by-case emissions limit. Given the May 1, 2026 compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule, we encourage owners and operators of affected units who believe they must seek case-by-case emissions limits to submit their requests to the EPA before the one-year deadline for such requests, if possible, to ensure adequate time for EPA review and to install the necessary controls.

For a source requesting a case-by-case limit due to technical impossibility, the final rule requires that the request include emissions data obtained through CEMS or stack tests, an analysis

[379] For examples of case-by-case RACT provisions and source specific limits for boilers in subpart Db of the EPA's NSPS, see 40 CFR 60.44b(f); Regulations of Connecticut State Agencies section 22a–174–22e; Code of Maryland Regulations section 26.11.09.08(B)(3); and Code of Maine Rules section 096–138–3, subsection (I).

of all available control technologies based on an engineering assessment by a professional engineer or data from a representative sample of similar sources, and a recommendation concerning the most stringent emissions limit the source can technically achieve.

For a source requesting a case-by-case limit on the basis of extreme economic hardship, the final rule requires that the request include at least three vendor estimates from three separate vendors that do not have a corporate or business-affiliation with the source of the costs of installing the control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of compliance with the applicable emissions limit for that particular source would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry under this rule. In evaluating a source's request for a case-by-case limit due to extreme economic hardship, the EPA will consider the emissions reductions and costs identified in this final rulemaking (and related support documents) for other sources in the relevant industry and whether the costs of compliance for the source seeking the case-by-case limit would significantly exceed the highest representative end of the range of estimated cost-per-ton figures identified for any source in the relevant industry as discussed in section V of this document.

As discussed in section VI.A of this document, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only "under particular circumstances and upon a sufficient showing of necessity," *e.g.,* when compliance with the statutory mandate amounts to an impossibility.[380] Given these directives, the EPA cannot allow a covered source to avoid complying with the emissions limits established in this final rule unless the source can demonstrate that compliance with the limit would either be impossible as a technical matter or result in an extreme economic hardship—*i.e.,* exceed the high end of the cost-effectiveness estimates that informed the EPA's Step 3 determination of significant contribution, as discussed in section V of this document. The criteria that must be met to qualify for a case-by-case limit are designed to meet this statutory mandate.

Comment: Several commenters raised concerns about the EPA's differing applicability criteria for the various non-EGU industries. Specifically, the commenters questioned why EPA set applicability criteria for engines in Pipeline Transportation of Natural Gas and non-EGU boilers based on design capacity instead of potential to emit (PTE). Commenters also requested that the EPA allow each non-EGU category to rely on operating permits or other federally enforceable instruments to avoid being subject to the rule, such as limits to the PTE or limits on fuels used.

Response: The 100 tpy PTE threshold and comparable design capacity thresholds of 1,000 horsepower (hp) for engines and 100 mmBtu/hr for boilers are appropriate to ensure that the final rule reduces emissions from the most impactful units. The EPA finds the control technologies assumed to be installed to meet the final emissions limits would not be as readily available or cost effective for emissions units with PTE or design capacities lower than the applicability thresholds in this final rule.

With regard to the selection of design capacity thresholds for boilers and engines, the EPA finds that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines and boilers based on design capacity rather than PTE. We further explain our basis for establishing applicability thresholds based on design capacity for these two source categories in sections VI.C.1. and VI.C.5. For consistency with preexisting requirements for engines and boilers and to capture the sizes of units identified in Step 3 of our analysis, the EPA selected design capacities of 1,000 hp for engines and 100 mmBtu/hr for boilers. The EPA recognizes that these applicability thresholds captured more units than the EPA intended, particularly some low-use units. Therefore, as explained in sections VI.C.1 and VI.C.5., the EPA is establishing exemptions for low-use boilers and emergency engines, as well as new emissions averaging provisions for engines, to ensure that this final rule focuses on larger, more impactful units.

The EPA also agrees with commenters that the applicability criteria should allow for sources to rely on enforceable requirements that limit a source's PTE and is finalizing a regulatory definition of PTE that is generally consistent with the definitions of that term in the EPA's title V and NSR permit programs. *See, e.g.,* 40 CFR 51.165(a)(1)(iii), 70.2. In constructing the list of potential sources subject to the final rule, the EPA relied on available information to identify the PTE of the emissions units in the various non-EGU industries that are captured by the applicability criteria. *See Memo to Docket titled Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs.* Thus, the EPA's Step 3 analysis takes into account available information about currently enforceable emissions limits and physical and operational limitations identified in existing permits. The EPA finds it necessary to define PTE consistent with its use in the title V and NSR permit programs to ensure that the requirements of the final FIPs apply to the most impactful units identified in Step 3 of our analysis. However, to ensure that these FIPs achieve the emissions reductions necessary to eliminate significant contribution or interference with maintenance as described in this final rule, the applicability criteria for the Cement and Concrete Manufacturing, Iron and Steel and Ferroalloy Manufacturing, and Glass and Glass Product Manufacturing industries take into account only those enforceable PTE limits in effect as of the effective date of this final rule. Thus, any emissions unit in these three industries that has a PTE equal to or greater than 100 tons per year and thus meets the definition of an "affected unit" as of August 4, 2023, will remain subject to the applicable FIPs, without regard to any PTE limit that the emissions unit may subsequently become subject to. Each affected unit in these three industries must submit an initial notification of applicability to the EPA by December 4, 2023, that identifies its PTE as of the effective date of this final rule. Additionally, any owner or operator of an existing emissions unit that is not an affected unit as of August 4, 2023, but subsequently meets the applicability criteria (*e.g.,* due to a change in fuel use that increases the unit's PTE) will become an affected unit subject to the applicable requirements of this final rule at that time.

Comment: In responding to the EPA's request for comment on whether some non-EGU units would need to run controls required by the final FIP year-round, one commenter anticipated that control equipment would be operated as necessary to achieve applicable emissions limits, but that operational

[380] *Wisconsin,* 938 F.3d at 316 and 319–320 (noting that any such deviation must be "rooted in Title I's framework" and "provide a sufficient level of protection to downwind States").

flexibility, cost considerations and equipment longevity would warrant operation of certain control equipment on a schedule such that the equipment would not be used when unnecessary to meet emissions limits and/or outside of ozone season (*i.e.,* during winter months). The commenter further explained that flexibility in the operation of certain control equipment when unnecessary to meet emissions limits will allow for routine maintenance and repairs without requiring variances or similar exemptions from continuous operation requirements.

Response: Based on the feedback received during the public comment period, the EPA is finalizing requirements for non-EGU sources that will apply only during the ozone season, which runs annually from May to September. As discussed in the proposed rule, this is consistent with EPA's prior practice in Federal actions to eliminate significant contribution of ozone in the 1998 NO_X SIP Call, CAIR, CSAPR, CSAPR Update, and the Revised CSAPR Update. In addition, the EPA did not receive any information during the public comment period suggesting that sources would have to run the necessary controls year-round due to the nature of those controls. We note, however, that certain emissions-control technologies, such as combustion controls that are integrated into the unit itself, would likely function to reduce NO_X emissions year-round as a practical engineering matter.

Comment: Regarding electronic reporting through the Compliance and Emissions Data Reporting Interface (CEDRI), one commenter requested that CEDRI reporting requirements be consolidated in one location rather than repeated in each section. Another commenter requested that EPA include electronic reporting requirements for MWCs and specifically require that MWCs report CEMS data to CEDRI. Another commenter requested that EPA allow for extensions of time for electronic reports due to technical glitches.

Response: To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators of non-EGU sources subject to the final FIPs, including MWCs, submit electronic copies of required initial notifications of applicability, performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the CEDRI. The final rule requires that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [381] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, the EPA is finalizing a requirement that performance evaluation results of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website, and a requirement that other performance evaluation results be submitted in PDF using the attachment module of the ERT. The final rule also requires that initial notifications of applicability, annual compliance reports, and excess emissions reports be submitted in PDF uploaded in CEDRI.

Furthermore, the EPA is finalizing, as proposed, provisions that allow owners and operators to seek extensions of time to submit electronic reports due to circumstances beyond the control of the owner or operator (*e.g.,* due to a possible outage in CDX or CEDRI or a *force majeure* event) in the time just prior to a report's due date, as well as provisions specifying how to submit such a claim. Public commenters supported these proposed provisions.

The EPA agrees with commenters that the CEDRI reporting requirements could be centralized and has moved the CEDRI reporting requirements to 40 CFR 52.40.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is finalizing regulatory requirements for the Pipeline Transportation of Natural Gas industry that apply to stationary, natural gas-fired, spark ignited reciprocating internal combustion engines (''stationary SI engines'') within these facilities that have a maximum rated capacity of 1,000 hp or greater. Based on our review of the potential emissions from stationary SI engines, we find that use of a maximum rated capacity of 1,000 hp reasonably approximates the 100 tpy PTE threshold used in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* as described in section V.B of this document.

The EPA is also modifying certain provisions in response to public comments to provide compliance flexibilities for the Pipeline Transportation of Natural Gas industry sector in order to focus emissions reduction efforts on the highest emitting units. Specifically, the EPA is finalizing an exemption for emergency engines, and establishing provisions that allow any owner or operator of an affected unit to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule.

For purposes of this rule, the EPA is clarifying and narrowing the definition of ''pipeline transportation of natural gas'' to mean the transport or storage of natural gas prior to delivery to a local distribution company custody transfer station or to a final end-user (if there is no local distribution company custody transfer station). The revised definition of this term in § 52.41(a) is consistent with the EPA's regulatory definition of ''natural gas transmission and storage segment'' in 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015).

The EPA is also adding definitions of the terms ''local distribution company'' and ''local distribution company custody transfer station'' that are consistent with the definitions found in 40 CFR 98.400 (subpart NN, Suppliers of Natural Gas and Natural Gas Liquids) and 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015), respectively.

Comment: Several commenters asked EPA to exclude emergency engines in the final rule and one commenter recommended that the EPA revise the definition of affected unit to specifically exempt emergency engines. Commenters stated that doing so would not only be consistent with other regulations applicable to stationary SI engines, but it would also be more consistent with EPA's applicability analysis, which assumes stationary SI engines will operate for 7,000 hours a year, something emergency engines are prohibited from doing by Federal regulation. Commenters also stated that emergency generators are currently exempt from requirements applicable to non-emergency RICE covered by both

[381] The ERT website is located at *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

the relevant NSPS rule (subpart JJJJ), as well as the relevant NESHAP rule (subpart ZZZZ), and that although the NSPS and NESHAP standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the ''potential to emit'' in issuing air permits for emergency RICE. One commenter asserted that emergency engines operating under other standards currently only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, that their emissions are low, and that their contribution to the ozone transport issues EPA's proposal seeks to address is negligible. Another commenter stated that the EPA has traditionally exempted emergency engines in past standards because the EPA has typically found that the use of add-on emissions controls cannot be justified due to the cost of the technology relative to the emissions reduction that would be obtained.

Response: With respect to stationary SI emergency engines, the EPA has reviewed the information submitted by the commenters and has decided to exempt such engines from the requirements of the final rule. Exemption of emergency engines is generally consistent with the EPA's treatment of emergency engines in other CAA rulemakings. *See, e.g.,* 40 CFR 63.6585(f). The EPA expects that this change from the proposed rule addresses the concerns expressed by the commenters about the requirements for stationary emergency engines.

The final rule defines emergency engines as engines that are stationary and operated to provide electrical power or mechanical work during an emergency situation. These engines are typically used only a few hours per year, and the costs of emissions control are not warranted when compared to the emissions reductions that would be achieved.

In the final rule, emergency engines are subject to certain compliance requirements on a continuous basis. Continuous compliance requirements include operating limitations that apply during non-emergency use but do not include emissions testing of emergency engines.

Comment: Several commenters raised concerns about the EPA's proposal to establish applicability criteria for engines in Pipeline Transportation of Natural Gas based on design capacity rather than PTE. Other commenters asserted that the horsepower rating of an engine does not necessarily correspond to its annual emissions and that engines with a rated capacity of more than 1,000 hp in this industry sector may operate at low load and/or infrequently and be associated with limited NO_X emissions. One commenter stated that most of the subject facilities in their state that have natural gas fired SI engines with a nameplate capacity rating of 1,000 hp or greater have annual NO_X emissions less than 100 tpy, with nearly 25 percent of them less than 25 tpy. The commenter suggested that the 1,000 hp applicability threshold would result in overcontrol. According to one commenter, the EPA has overestimated the emissions rates and operating hours of engines with a rated capacity of more than 1,000 hp and thus underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy of NO_X annually. According to this commenter, only engines much larger than 1,000 hp are likely to emit at the level EPA deemed appropriate for regulation.

Another commenter suggested that the EPA should use a 150 ton per year threshold that the commenter alleges was used in the Revised CSAPR Update rulemaking so that stationary SI engines are regulated on equal footing with EGUs and raise the 1,000 hp threshold to 2,000 hp, which according to the commenter would not sacrifice the emissions reductions to be achieved.

Response: As explained in the proposal, the EPA found that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines based on design capacity rather than PTE. For consistency with preexisting requirements for engines, the EPA selected a design capacity of 1,000 hp for engines to capture the sizes of units identified in Step 3 of our analysis. Based on the Non-EGU Screening Assessment memorandum, engines with a potential to emit of 100 tpy or greater had the most significant potential for NO_X emissions reductions. The EPA recognizes that the use of a 1,000 hp design capacity as part of the applicability criteria may capture low-use units and some units with emissions of less than 100 tons per year. However, it is also not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future. As discussed in section V of this document, we continue to find that collectively engines with a design capacity of 1,000 hp or higher in the states and industries covered by this final rule emit substantial amounts of NO_X that significantly contribute to downwind air quality problems.

However, in response to concerns raised by commenters while continuing to ensure that this rule establishes an effective emissions control program for these units that is consistent with our Step 3 determinations, the EPA is establishing a compliance alternative using facility-wide emissions averaging, which will allow facilities to prioritize emissions reductions from larger, higher-emitting units. (As previously discussed, we are also establishing an exemption for emergency engines, which also helps ensure that this final rule focuses on larger, more impactful units in this industry.) The facility-wide emissions averaging alternative is explained in the following paragraphs.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, the EPA reviewed RACT NO_X rules, air permits, and OTC model rules. While some permits and rules express engine emissions limits in parts per million by volume (ppmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). The EPA has historically set emissions limits for these types of engines using g/hp-hr and finds that method appropriate for this final FIP as well.

Based on the available information for this industry, including applicable State and local air agency rules and active air permits issued to sources with similar engines, the EPA is finalizing the following emissions limits for stationary SI engines in the covered states. Beginning in the 2026 ozone season and in each ozone season thereafter, the following emissions limits apply, based on a 30-day rolling average emissions rate during the ozone season:

TABLE VI.C–1—SUMMARY OF FINAL NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

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

The EPA anticipates that, in some cases, affected engines will need to install NO_X controls to comply with the final emissions limits in Table VI.C–1. The emissions limits for four stroke rich burn engines, four stroke lean burn engines and two stroke lean burn engines are designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines; installing SCR on existing four stroke lean burn engines; and retrofitting layer combustion on existing two stroke lean burn engines as identified in the Final Non-EGU Sectors TSD. Sources have the flexibility to install any other control technologies that enable the affected units to meet the applicable emissions limit on a continuous basis.

The EPA is establishing provisions that allow any owner or operator of an affected unit in the Pipeline Transportation of Natural Gas Industry to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. These provisions will provide some flexibility to owners and operators of affected units to determine which engines to control and at what level, so long as the average emissions across all covered units, on a weighted basis, meet the applicable emissions limits for each engine type. This approach allows facilities to target the most cost-effective emissions reductions and to avoid installing controls on equipment that is infrequently operated.

We provide a more detailed discussion of the basis for the final emissions limits and the anticipated control technologies to be installed in the Final Non-EGU Sectors TSD.

Four Stroke Rich Burn and Four Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit is appropriate for four stroke rich burn engines since even an assumed reduction of 95 percent would result in most engines being able to achieve an emissions rate of 0.5 g/hp-hr. The EPA also requested comment on whether a lower or higher emissions limit is appropriate for four stroke lean burn engines.

Comment: One commenter stated that the limits as proposed were not technically feasible in all circumstances. The commenter explained that its company has 150 four stroke rich burn engines in its fleet and that some of those engines cannot achieve the proposed 1.0 g/hp-hr limit even with both NSCR and layered combustion due to the vintage design of the individual cylinder geometry and the fact that most of these engines are not in production today, which limits availability of parts and retrofit technologies. The commenter asserted that 10 of its four stroke rich burn engines have all available controls on them and half of those still exceed the proposed limits. The commenter estimated that 10 of its four stroke lean burn engines would require SCR to meet the 1.5 g/hp-hr limit and that this control installation would require custom retrofit due to the age of these engines. Furthermore, the commenter stated that if current limits are not achievable in all circumstances, then lower limits are likewise impossible for four stroke rich burn engines and four stroke lean burn engines in even more circumstances. The commenter stated that the technical feasibility of installing controls on any single existing engine varies and depends, in part, on site-specific and engine-specific considerations such as space for the installation of the control, the availability of sufficient power, the emissions reductions required to meet the applicable standards, and the vintage, make, and model of a particular engine. Another commenter recommended tightening the proposed emissions standards for four stroke lean burn engines to an emissions limit similar to Colorado's limit of 1.2 g/hp-hr. A third commenter noted that the District of Columbia Department of Energy and Environment has NO_X emissions limits for both rich- and lean burn engines burning natural gas at 0.7 g/hp-hr.

Response: The EPA is finalizing the emissions limits for both four stroke rich burn engines and four stroke lean burn engines as proposed but also establishing alternative compliance provisions and criteria for establishing case-by-case alternative emissions limits in response to the concerns raised by commenters. NSCR can achieve NO_X reductions of 90 to 99 percent, and engines in California, Colorado, Pennsylvania and Texas have achieved the emissions limits that the EPA had proposed. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 1.0 g/hp-hr emissions limit for four stroke rich burn engines and a 1.5 g/hp-hr emissions limit for four stroke lean burn engines. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

To address the concerns raised by some commenters that not all engines may be able to achieve the emissions limits as proposed due to engine vintage and technical constraints, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. An approved Facility-Wide Averaging Plan would allow the owner or operator of the facility to identify the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs). In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. The provisions governing case-by-case alternative limits are explained in more detail in section VI.C of this document.

Two Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit would be achievable with layered combustion alone for the two stroke lean burn engines covered by this final rule. The

EPA also sought comment on whether these engines could install additional control technology at or below the marginal cost threshold to achieve a lower emissions rate.

Comment: Commenters did not specifically address whether a lower emissions limit would be achievable with layered combustion alone at two stroke lean burn engines. However, one commenter stated that older two stroke lean burn engines generally would not be able to achieve the proposed NO_X emissions limits. The commenter stated that conversion kits are available for several models that can reduce emissions but that such kits are not made for all models, especially older stationary engines. Commenters further stated that where conversion kits are not available, a company would likely have no choice but to replace the older four stroke or two stroke stationary engines, typically at a cost of $2 million to $4 million each.

Two commenters stated that they are required by their state agency to have RACT, BACT, or BART controls, at minimum. Commenters stated that requiring additional controls at facilities already equipped with RACT, BACT or BART control technologies would not achieve the anticipated emissions reductions due to operational factors inherent in the preexisting and pre-controlled equipment and that the achievability of targeted control levels is highly dependent upon a number of variables at each facility.

Another commenter suggested that the EPA set lower limits for two stroke lean burn engines similar to the OTC-recommended limits in the range of 1.5–2.0 g/hp-hr.

Response: Information currently available to the EPA indicates that the amount of emissions reductions achievable with layered combustion controls is unit specific and can range from a 60 to 90 percent reduction in NO_X emissions. The EPA estimates that existing uncontrolled two stroke lean burn engines would need to reduce emissions by up to 80 percent to comply with a 3.0 g/hp-hr emissions limit. The EPA has found that engines in California, Colorado, Pennsylvania and Texas have achieved these emissions rates. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 3.0 g/hp-hr emissions limit for two stroke lean burn engines. Although some affected units may be able to achieve a lower emissions rate, we find that a 3.0 g/hp-hr emissions limit generally reflects a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. As explained in the proposed rule and expressed by public commenters, if the EPA were to establish an emissions limit lower than 3.0 g/hp-hr, some two stroke lean burn engines would not be able to meet the emissions limit with the installation of layered combustion control alone. In that case, the lower limit might require the installation of SCR, which the EPA did not find to be cost-effective for two stroke lean burn engines in its Step 3 analysis.[382] The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for this emissions limit.

In response to commenters' concerns about the difficulties involved in retrofitting or replacing older stationary engines to achieve the EPA's proposed emissions limit, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. However, in the context of older or "vintage," high-emitting engines in this industry for which commenters claim emissions control technology retrofit is not feasible, the Agency anticipates taking into consideration the cost associated with alternative compliance strategies, such as replacement with new, far more efficient and less polluting engines, in evaluating claims of extreme economic hardship.

Facility-Wide Averaging Plan

The EPA is finalizing regulatory text that provides for an emissions limit compliance alternative using facility-level emissions averaging. An approved Facility-Wide Averaging Plan will allow the owner or operator of the facility to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control). So long as all of the emissions units covered by the Facility-Wide Averaging Plan collectively emit less than or equal to the total amount of NO_X emissions (in tons per day) that would be emitted if each covered unit individually met the applicable NO_X emissions limitations, the covered units will be in compliance with the final rule. Under this alternative compliance option, facilities have the flexibility to prioritize emissions reductions from larger, dirtier engines.

Comment: Several commenters recommended that the EPA promulgate emissions averaging provisions, as it did in the 2004 NO_X SIP Call Phase 2 rule (69 FR 21604), in which the EPA evaluated and supported reliance on emissions averaging for RICE in the Pipeline Transportation of Natural Gas industry sector. The commenter stated that the EPA's guidance to states on developing an appropriate SIP in response to the SIP Call provided companies the "flexibility" to use a number of control options, as long as the collective result achieved the required NO_X reductions, and that many states built their revised SIPs around the emissions averaging approach addressed in this guidance document.[383] One commenter recommended that the EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company. Another commenter asserted that units of certain vintages and units from certain manufacturers will not be able to meet the emissions rate limits the EPA had proposed. The commenter claimed that, absent a system based on source-specific emissions limits, emissions averaging is one of the only practical mechanisms for addressing these challenges.

One commenter stated that it had evaluated the cost of controls for engines in its fleet and that the variety in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program. Another commenter advocated for an emissions averaging plan that would allow an engine-by-engine showing of economic infeasibility to ensure a cost-effective application of the emissions standards, a reduced impact on natural gas capacity, and a means for addressing the problem presented by achieving

[382] 87 FR 20036, 20143 (noting that an emissions limit below 3.0 g/hp-hr may require some two stroke lean burn engines to install additional controls beyond the EPA's cost threshold).

[383] The commenter refers to an August 22, 2002 memorandum from Lydia N. Wegman, Director, EPA, Air Quality Strategies and Standards Division to EPA Air Division Directors, entitled "State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NO_X)—Stationary Reciprocating Internal Combustion Engines."

compliance on engines that are technically impossible to retrofit.

One commenter stated that the EPA should also consider allowing companies to choose a mass-based alternative that would ensure emissions reductions align with the tons per year reductions upon which the EPA based its significant contribution and over-control analyses.

Response: Based upon the EPA's 2019 NEI emissions inventory data, the EPA estimates that a total of 3,005 stationary SI engines are subject to the final rule. The EPA recognizes that many low-use engines are captured by the 1,000 hp design capacity applicability threshold. In the process of reviewing public comments, the EPA reviewed emissions averaging plans found in state air quality rules for Colorado, Illinois, Louisiana, New Jersey, and Tennessee.[384] Based on these additional reviews, the EPA is finalizing in § 52.41(c) of this final rule an emissions limit compliance alternative using facility-level emissions averaging. Emissions averaging plans will allow facility owners and operators to determine how to best achieve the necessary emissions reductions by installing controls on the affected engines with the greatest emissions reduction potential rather than on units with lower actual emissions where the installation of controls would be less cost effective. The final rule defines "facility" consistent with the definition of this term as it generally applies in the EPA's NSR and title V permitting regulations,[385] with one addition to make clear that, for purposes of this final rule, a "facility" may not extend beyond the boundaries of the 20 states covered by the FIP for industrial sources, as identified in § 52.40(b)(2). Because a facility cannot extend beyond this geographic area, a Facility-Wide Averaging Plan also cannot extend beyond the 20-state area covered by the FIP.

To estimate the number of facilities that may take advantage of the Facility-Wide Averaging Plan provisions, and the number of affected units that would install controls under such an emissions averaging plan, the EPA conducted an analysis on a subset of the estimated 3,005 stationary IC engines subject to the final rule. The EPA evaluated the reported actual NO_X emissions data in tpy from a subset of facilities in the covered states using 2019 NEI data for stationary IC engines with design capacities of 1,000 hp or greater. The EPA then identified a number of facilities that have more than one affected engine, calculated each facility's emissions "cap" as the total NO_X emissions (in tpy) allowed facility-wide based on the unit-specific NO_X emissions limits applicable to all affected units at the facility, and identified a number of higher-emitting engines at each facility that were candidates for having controls installed. For engines that EPA identified were likely to install controls, the EPA assumed that four stroke rich burn engines, four stroke lean burn engines, and two stroke lean burn engines could achieve a NO_X emissions rate of 0.5 g/hp-hr with the installation of SCR based on data obtained from the Ozone Transport Commission report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012). For the remaining engines identified as uncontrolled, the EPA assumed a NO_X emissions rate of 16 g/hp-hr for all engine types. Thus, under the assumed averaging scenarios, engines with controls installed would achieve emissions levels below the emissions limits in the final rule and would offset the higher emissions from the remaining uncontrolled units.

The EPA then calculated the total facility-wide emissions (in tpy) under various assumed averaging scenarios and compared those totals to each facility's calculated emissions cap (in tpy) to estimate the number of affected units at each facility that would need to install controls to ensure that total facility-wide emissions remained below the emissions cap. Based on these analyses, the EPA found that emissions averaging should allow most facilities to install controls on approximately one-third of the engines at their sites, on average, while complying with the applicable NO_X emissions cap on a facility-wide basis. For a more detailed discussion of the EPA's analysis and related assumptions, see the Final Non-EGU Sectors TSD.

The Facility-Wide Averaging Plan provisions that the EPA is finalizing provide the flexibility needed to address the concerns about the costs of emissions control installations for certain stationary SI engines, by allowing facility owners and operators to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control).

An owner or operator of a facility containing more than one affected unit may elect to use an EPA-approved Facility-Wide Averaging Plan as an alternative means of compliance with the NO_X emissions limits in § 52.41(c). The owner or operator of such a facility must submit a request to the EPA that, among other things, specifies the affected units that will be covered by the plan, provides facility and unit-level identification information, identifies the facility-wide emissions "cap" (in tpd) that the facility must comply with on a 30-day rolling average basis, and provides the calculation methodology used to demonstrate compliance with the identified emissions cap. The EPA will approve a request for a Facility-Wide Averaging Plan if the EPA determines that the facility-wide emissions total (in tpd), based on a 30-day rolling emissions average basis during the ozone season, is less than the emissions cap (in tpd) and the plan establishes satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, and recordkeeping requirements.

Compliance Assurance Requirements

The EPA is requiring owners and operators of affected units to conduct annual performance tests in accordance with 40 CFR 60.8 to demonstrate compliance with the NO_X emissions limit in this final rule. The EPA is also requiring owners and operators to monitor and record hours of operation and fuel consumption and to use continuous parametric monitoring systems to demonstrate ongoing compliance with the applicable NO_X emissions limit. For example, owners and operators of engines that utilize layered combustion controls will need to monitor and record temperature, air to fuel ratio, and other parameters as appropriate to ensure that combustion conditions are optimized to reduce NO_X emissions and assure compliance with the emissions limit. For engines using SCR or NSCR, owners and operators must monitor and record parameters such as inlet temperature to the catalyst

[384] *See* Code of Colorado Regulations, Regulation Number 7 (5 CCR 1001–9), Part E, Section I.D.5.c., Illinois Administrative Code, Title 35, Section 217.390, Louisiana Administrative Code, Title 33, Section 2201, New Jersey Administrative Code, Title 7, Chapter 27, Section 19.6, and Rules of the Tennessee Dept. of Environment and Conservation, Rule 1200–03–27–.09.

[385] See 40 CFR 51.165(a)(1)(ii)(A), 51.166(b)(6)(i), and 52.21(b)(6)(i) (defining "building, structure, facility, or installation" for Nonattainment New Source Review and Prevention of Significant Deterioration permits) and *Natural Resources Defense Council* v. *EPA,* 725 F.2d 761 (D.C. Cir. 1984) (vacating and remanding EPA's categorial exclusion of vessel activities from this definition); see also 40 CFR 70.2 (defining "major source" for title V operating permits).

and pressure drop across the catalyst. For affected engines that meet the certification requirements of § 60.4243(a), however, the facility-wide emissions calculations may be based on certified engine emissions standards data pursuant to § 60.4243(a), instead of performance tests.

In calculating the facility-wide emissions total during the ozone season, affected engines covered by the Facility-Wide Averaging Plan must be identified by each engine's nameplate capacity in horsepower, its actual operating hours during the ozone season, and its emissions rates in g/hp-hr from certified engine data or from the most recent performance test results for non-certified engines according to § 52.41(e).

Comment: Several commenters stated that semi-annual performance testing would not be appropriate due to its high costs and limited benefits. One commenter proposed a ''step-down'' testing alternative that could be conducted after establishing an engine's initial compliance via performance testing. Under this approach, owners and operators would conduct one performance test and would only need to conduct a second performance test within a given year if the first performance test demonstrated that an engine was not meeting the applicable emissions standards.

Another commenter asserted that to test all of its 950 units, a minimum of 12 months would be needed rather than the six months the EPA had proposed to provide (or five months if the EPA would require one of the semi-annual tests to be conducted during the ozone season). The commenter stated that the EPA had accounted for these operational realities in the past and that under the NSPS and NESHAP, testing is generally required only once for every 8,760 hours of run time. The commenter asserted that there is no reason to require more frequent testing than those required under the NSPS and NESHAP.

Several commenters requested that the EPA allow for reduction in the frequency of testing to once every two years if testing shows that NO_X emissions are no more than 75 percent of permitted NO_X emissions limits. In addition, several commenters stated that since the rule is intended to address the ozone season, a single, annual test is more feasible than semi-annual testing and reporting.

Response: For the stationary SI engines subject to this final rule, the EPA is revising the frequency of required performance tests from a semi-annual basis to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the 5-month ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to determine continuous compliance during the ozone season. The EPA also agrees with commenters that the annual tests required under the final rule need not occur during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: Commenters generally stated that requiring CEMS would add an unnecessary cost and complexity, would provide no emissions reduction benefit for the affected units the proposed FIP intends to control and are not warranted due to the availability of other established methods of compliance assurance, such as parametric monitoring and periodic testing. One commenter stated that requiring CEMS would add unnecessary CEMS testing obligations. Another commenter stated that the costs associated with CEMS and frequent performance testing on affected RICE would be as much, if not more, than the costs associated with installation and operation of some of the control technologies EPA has considered in setting the proposed emissions limits. According to one commenter, the EPA has traditionally agreed with this viewpoint on the high cost of CEMS, as most stationary engines are not currently required under the NSPS or NESHAP to install or operate CEMS.

Another commenter stated that in addition to cost, there are other barriers to installing CEMS on RICE across the Pipeline Transportation of Natural Gas industry. Many RICE in the Pipeline Transportation of Natural Gas industry are located at remote, unstaffed locations, meaning that there would be no staff available to respond and react to communication or alarms from CEMS.

Response: The EPA acknowledges the costs associated with the installation and maintenance of CEMS at affected units in the Pipeline Transportation of Natural Gas industry and agrees that it is not necessary to require CEMS for purposes of compliance with the requirements of this final rule for this industry. Accordingly, the EPA is not finalizing requirements for affected units in this industry sector to install or operate CEMS. Instead, the EPA is requiring parametric monitoring protocols, as described earlier, coupled with an annual performance test, which will ensure that the emissions limits are legally and practically enforceable on a continuous basis, and that data are recorded, reported, and can be made publicly available, ensuring the ability of state and Federal regulators and other persons under CAA sections 113 and 304 to enforce the requirements of the Act.

2. Cement and Concrete Product Manufacturing

Applicability

For cement kilns in the Cement and Cement Product Manufacturing industry, the EPA is finalizing the proposed applicability provisions without change. The affected units in this industry are cement kilns that emit or have a PTE of 100 tpy or more of NO_X. The EPA received comments regarding the definition of PTE, which we address in section VI.C, but no comments concerning the 100 tpy PTE threshold for applicability purposes.

Emissions Limitations and Rationale

As explained in the proposal, the EPA based the proposed emissions limits for cement kilns on the types of limits being met across the nation in RACT NO_X rules, NSPS, air permits, and consent decrees. Based on these requirements, the EPA proposed emissions limits in the form of mass of pollutant emitted (in pounds) per kiln's clinker output (in tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced during a 30-operating day rolling average period. Further, the EPA proposed specific emissions limits for long wet, long dry, preheater, precalciner, and combined preheater/precalciner kilns. The EPA also proposed a daily source cap limit that would apply to all units at a facility. Based on information received from public comments, the EPA is removing the daily source cap limit but finalizing the emissions limits as proposed in all other respects, as shown in Table VI.C–2.

TABLE VI.C–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

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

Comment: Numerous commenters raised concerns about designing a source cap limit based on average annual production in tons of clinker and kiln type. Commenters stated that the source cap limit equation as used in a prior action applied to long wet and dry preheater-precalciner or precalciner kilns and did not include other kiln types. Commenters expressed concern that the CAP2015 Ozone Transport equation the EPA proposed in this rule could lead to artificially low and restrictive daily emissions caps for facilities that experienced a temporary decrease in production due to the COVID–19 pandemic, during the historical three-year period proposed for use in determining the NO_X source cap. Also, commenters expressed concern that the proposed daily emissions cap limit originated as a local or regional limit for a single county and would not be appropriate for national application without further evaluation taking into account the specific characteristics of cement kilns in other states. One commenter suggested more stringent emissions limits than those the EPA had proposed for individual kiln types.

Response: The EPA is not finalizing the proposed daily source cap limit as the Agency agrees with the commenters that this proposed limit would be unnecessarily restrictive and was based on a formula that did not include all kiln types. Given the unusual reduction in cement production activities due to the COVID–19 pandemic, production rates during the 2019–2021 period are not representative of cement plants activities generally. Accordingly, use of the proposed daily source cap limit would result in an artificially restrictive NO_X emissions limit for affected cement kilns, particularly when this sector operates longer hours during the spring and summer construction season. With respect to those comments supporting more stringent emissions limits than those the EPA proposed for individual kiln types, we disagree given the significant differences among different kilns in design, configuration, age, fuel capabilities, and raw material composition. The EPA finds that the ozone season emissions limits for individual kiln types listed in Table VI.C–2 will achieve the necessary emissions reductions for purposes of eliminating significant contribution as defined in section V and is, therefore, finalizing these emissions limitations without change.

Comment: One commenter supported retirement of existing long wet kilns and replacement of these kilns with modern kilns. Other commenters opposed the phase out and retiring of these kilns, stating that many of the screened kilns have SNCR already installed and questioning whether replacement of existing long wet kilns is cost-effective. Some commenters also stated that according to EPA's "NO_X Control Technologies for the Cement Industry, Final Report," SNCR is not an appropriate NO_X control technique for long wet kilns.

Response: The EPA appreciates the challenges identified by commenters, such as site-specific technical evaluation and review and significant capital investment associated with undertaking kiln conversions or to install new kilns and is not finalizing any requirements to replace existing long wet kilns in this rule.

Comment: Several commenters expressed concern about the supply chain issues relevant to the procurement, design, construction, and installation of control devices, as well as securing related contracts, for the cement industry, particularly when cement sources will be competing with the EGU and other industrial sectors for similar services. One commenter stated that many preheater/precalciner kilns are already equipped with SNCR and that one facility not equipped with SNCR is already meeting NO_X emissions levels of 1.95 lb/ton of clinker or less. The commenter stated that the EPA should revise its assessment of potential NO_X reductions and cost estimates by accurately accounting for existing operating efficiencies and control devices at cement kilns.

Response: The EPA's response to comments on the time needed for installation of controls for non-EGU sources is provided in section VI.A. Regarding the comment that certain facilities may already have SNCR control technology installed, we recognize that many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

Compliance Assurance Requirements

The EPA received no comments on the proposed test methods and procedures provisions for the cement industry. Therefore, we are finalizing the proposed test methods and procedures for affected cement kilns without change.

Comment: Commenters generally supported requiring performance testing or installation of CEMS on affected cement kilns. Some commenters suggested that no performance testing should be required and others suggested that performance testing should only be required when a title V permit is due for renewal (every 5 years). One commenter suggested requiring sources to conduct stack tests during the ozone season.

Response: Affected kilns that operate a NO_X CEMS may use CEMS data consistent with the requirements of 40 CFR 60.13 in lieu of performance tests to demonstrate compliance with the requirements of this final rule. For affected kilns subject to this final rule that do not employ NO_X CEMS, the EPA is adjusting the performance testing frequency and requiring kilns to conduct a performance test on an annual basis during a given calendar year.[386] The EPA finds that annual performance testing and recordkeeping of cement production and fuel consumption during the ozone season will assure compliance with the emissions limits during the ozone season (May through September) each year for purposes of this rule. The required annual performance test may be performed at any time during the calendar year. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: One commenter stated that CEMS has been used successfully at its facility. Another commenter explained that the inside of a cement kiln is an extremely challenging environment for making any kind of continuous measurement as temperatures are high, and there is a lot of dust and tumbling clinker can damage in situ measuring instruments.

Response: The majority of cement kilns in the United States are already equipped with CEMS. However, in response to commenters concerns regarding the installation of CEMS, the EPA is finalizing alternative compliance requirements in lieu of CEMS. Owners or operators of affected emissions units without CEMS installed must conduct annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. Specifically, owners or operators of affected units without CEMS must monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is establishing emissions control requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to reheat furnaces that directly emit or have the potential to emit 100 tpy or more of NO_X. After review of all available information received during public comment, the EPA has determined that there is sufficient information to determine that low-NO_X burners can be installed on reheat furnaces. As explained further in the Final Non-EGU Sectors TSD, the EPA identified 32 reheat furnaces with low-NO_X burners installed and has concluded that low-NO_X burners are a readily available and widely implemented emissions reduction strategy.[387] This rule defines reheat furnaces to include all furnaces used to heat steel product—metal ingots, billets, slabs, beams, blooms and other similar products—to temperatures at which it will be suitable for deformation and further processing.

Comment: Several industry commenters requested that the EPA not include certain iron and steel emissions units—including blast furnaces, basic oxygen furnaces (BOFs), ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces (EAFs)—in the final rule as proposed due to, among other things, the uniqueness of each emissions unit, various design-related challenges, and expected impossibility of successful implementation of add-on NO_X control technology. Commenters expressed concern about requirements to install SCR for all iron and steel units for which the EPA proposed emissions limits. The commenters stated that iron and steel units had not installed SCR except in a few rare instances for experimental reasons and that SCR technology was not readily available or known for the iron and steel industry, unlike the control technologies expected to be installed in other non-EGU industries. Furthermore, commenters stated that SCR had not been applied for RACT, BACT, or LAER purposes on iron and steel units.

Response: In light of the comments we received on the complex economic and, in some cases, technical challenges associated with implementation of NO_X control technologies on certain emissions units in this sector, the EPA is not finalizing the proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

The EPA is aware of many examples of low-NO_X technology utilized at furnaces, kilns, and other emissions units in other sectors with similar stoichiometry, including taconite kilns, blast furnace stoves, electric arc furnaces (oxy-fuel burners), and many other examples at refineries and other large industrial facilities. The EPA anticipates that with adequate time, modeling, and optimization efforts, such NO_X reduction technology may be achievable and cost-effective for these emissions units in the Iron and Steel Mills and Ferroalloy Manufacturing sector as well. However, the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NO_X controls, including SCR or other NO_X control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry. We provide a more detailed discussion of the economic and technical issues associated with implementation of NO_X control technologies on these emissions units, including information provided by commenters, in section 4 of the Final Non-EGU Sectors TSD.

Reheat furnaces are the only type of emissions unit within the Iron and Steel Mills and Ferroalloy Manufacturing industry that this final rule applies to. Low-NO_X controls (*e.g.,* low-NO_X burners) are a demonstrated control technology that many reheat furnaces have successfully employed.

Comment: One commenter claimed that the proposed definition of "reheat furnaces" is overly vague and requested that the EPA amend the definition. Specifically, the commenter asserted that the EPA's proposed definition does not indicate what counts as "steel product" and whether this includes only products that have already been manufactured into some form before being introduced to a reheat furnace, or whether it also includes steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product. The commenter referenced the definition of reheat furnaces in Ohio's RACT regulations as an example to consider.

Response: In response to these comments, the EPA is finalizing a definition of reheat furnaces that is consistent with the definition in Ohio's NO_X RACT regulations. *See* Ohio Admin. Code 3745–110–01(b)(35) (March 25, 2022). Specifically, the EPA is defining reheat furnaces to mean "all furnaces used to heat steel product, including metal ingots, billets, slabs, beams, blooms and other similar products, to temperatures at which it will be suitable for deformation and further processing."

[386] 40 CFR 63.11237 "Calendar year" defined as the period between January 1 and December 31, inclusive, for a given year.

[387] See Final Non-EGU Sectors TSD, Section 4.

Emissions Control Requirements, Testing, and Rationale

Based on the available information for this industry, applicable Federal and state rules, and active air permits or enforceable orders issued to affected facilities in the iron and steel and ferroalloy manufacturing industry, the EPA is finalizing requirements for each facility with an affected reheat furnace to design, fabricate and install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by at least 40 percent by volume, and to conduct performance testing before and after burner installation to set emissions limits and verify emissions reductions from pre-installation emissions rates. Each low-NO_X burner shall be designed to achieve at least 40 percent NO_X reduction from existing reheat furnace exhaust emissions rates. Each facility with an affected reheat furnace shall, within 60 days of conclusion of the post-installation performance test, submit testing results to the EPA to establish NO_X emissions limits over a 30-day rolling average. Each proposed emissions limit must be supported by performance test data and analysis.

In evaluating potential emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees. These rules and source-specific requirements most commonly express emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hour) (*i.e.,* pounds of NO_X emitted per production hour), pounds per energy unit (*i.e.,* million British thermal unit (mmBtu)), or pounds of NO_X per ton of steel produced. Regulated iron and steel facilities, including facilities operating reheat furnaces in this sector, routinely monitor and keep track of production in terms of tons of steel produced per hour (heat rate) as it pertains to each facility's rate of iron and steel production. Several facilities, including Steel Dynamics, Columbia, Indiana, Cleveland-Cliffs, Cleveland, Ohio, and Cleveland-Cliffs, Burns Harbor, Indiana, are already operating various types of reheat furnaces with low-NO_X burners and achieving emissions rates as low as 0.11 lb/mmBtu of NO_X. The EPA identified at least nine reheat furnaces with a PTE greater than 100 tpy, including slab, rotary hearth, and walking beam furnaces, that have installed low-NO_X burners and are achieving various emissions rates.[388]

Due to variations in the emissions rates that different types of reheat furnaces can achieve, the EPA is not finalizing one emissions limit for all reheat furnaces and is instead requiring the installation of low-NO_X burners or equivalent low-NO_X technology designed to achieve a minimum 40 percent reduction from baseline NO_X emission levels, together with source specific emissions limits to be set thereafter based on performance testing. Specifically, the final rule requires that each owner or operator of an affected unit submit to the EPA, within one year after the effective date of the final rule, a work plan that identifies the low-NO_X burner or alternative low-NO_X technology selected, the phased construction timeframe by which the owner or operator will design, install, and consistently operate the control device, an emissions limit reflecting the required 40 percent reduction in NO_X emission levels, and, where applicable, performance test results obtained no more than five years before the effective date of the final rule to be used as baseline emissions testing data providing the basis for the required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing to establish baseline emissions data.

Comment: One commenter stated that the standard practice for setting NO_X limits for iron and steel sources often requires consideration of site or unit-specific issues. Similarly, another commenter stated that a single limit would not provide an adequate basis for establishing NO_X emissions limits that will universally apply to multiple, unique facilities. The same commenter stated that NO_X reduction in certain furnaces is routinely achievable by combustion controls or measures other than SCR.

Response: The EPA acknowledges the difficulty in crafting one emissions limit for multiple iron and steel facilities and units of varying size, age, and design, in light of the unique issues associated with varying unit types in this particular industry. We also acknowledge that in some cases, reheat furnaces are equipped with recently installed, high-efficiency low-NO_X burners. Many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

The EPA is finalizing requirements for reheat furnaces to install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by 40 percent by volume, and to perform pre- and post-installation performance testing at exhaust outlets to determine rate-based emissions limits for reheat furnaces in lb/hour, lb/mmBtu, or lb/ton on a rolling 30-operating day average. Owners and operators of affected units must also monitor NO_X emissions from reheat furnaces using CEMS or annual performance testing and recordkeeping and operate low-NO_X burners in accordance with work practice standards set forth in the regulatory text. Due to the many types of emissions units within the Iron and Steel Mills and Ferroalloy Manufacturing industry, and the limited information available at this time regarding NO_X control options that are achievable for these units, the EPA is finalizing requirements only for reheat furnaces at this time.

Comment: Commenters expressed concern that the proposed emissions limits identified both a 3-hour and a 30-day averaging time for the same limits and requested that the EPA clarify the averaging time in the final rule. Commenters requested that the EPA finalize limits with a 30-day averaging time consistent with the requirements for other non-EGU industries.

Response: In determining the appropriateness of 30-day rolling averaging times, the EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63, subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63, subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63, subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63, subpart YYYYYY. The EPA also reviewed

[388] Specifically, through a review of title V permits, the EPA identified reheat furnaces with low-NO_X burners installed at Steel Dynamics in Columbia City, Indiana (two furnaces), Steel Dynamics in Butler, Indiana (one furnace), Cleveland Cliffs in Burns Harbor, Indiana (four furnaces), Cleveland Cliffs in East Chicago, Indiana (one furnace), and Cleveland Cliffs in Cleveland, Ohio (one furnace). For a further discussion of the limits and information on these facilities, see the Final Non-EGU Sectors TSD.

various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information and the information provided by public commenters, the EPA is requiring a 30-operating day rolling average period as the averaging timeframe for reheat furnaces. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while providing the flexibility needed to address fluctuations in operations and production.

Compliance Assurance Requirements

The EPA is finalizing requirements for each owner or operator of an affected unit in the Iron and Steel Mills and Ferroalloy Manufacturing industry to use CEMS or annual performance tests and continuous parametric monitoring to determine compliance with the 30-day rolling average emissions limit during the ozone season. Facilities choosing to use CEMS must perform an initial RATA per CEMS and maintain and operate the CEMS according to the applicable performance specifications in 40 CFR part 60, appendix B. Facilities choosing to use testing and continuous parametric monitoring for compliance purposes must use the test methods and procedures in 40 CFR part 60, appendix A–4, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures.

Comment: Several commenters raised concerns with the requirement to install and operate CEMS to monitor NO_X emissions. Commenters cited the high relative costs of installing CEMS, especially for smaller units with lower actual emissions, and the complexities with installing CEMS on mobile reheat furnaces. Further, commenters explained that due to the unique configuration of certain facilities, it would be impossible for a CEMS to differentiate emissions from a reheat furnace and other units, like waste heat boilers. As an alternative to CEMS, commenters requested that the EPA finalize similar monitoring and recordkeeping requirements as proposed for the Cement and Concrete Product Manufacturing industry in the proposed rule, which allow for CEMS or performance testing and recordkeeping. Commenters explained that for reheat furnaces that are natural gas-fired, emissions can be tracked by relying on vendor guarantees and emissions factors and natural gas throughput.

Response: The EPA reviewed comments received from the industry regarding their concerns of affected units within the iron and steel mills and ferroalloy manufacturing sector being required to demonstrate compliance through CEMS. The EPA acknowledges the cost associated with the installation and maintenance of CEMS to demonstrate compliance with the finalized emissions standards for reheat furnaces. In this final rule, the EPA is revising the compliance assurance requirements to provide flexibility to owners or operators of affected units. Compliance may be demonstrated through CEMS or annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. For sources relying on annual performance tests and continuous parametric monitoring to assure compliance, the EPA is requiring that sources keep records of production and fuel usage during the ozone season to assure compliance with the emissions limits on a 30-day rolling average basis. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is finalizing regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to furnaces that directly emit or have a PTE of 100 tpy or more of NO_X. For this industry, the EPA is finalizing the proposed applicability provisions without change.

Comment: One commenter requested that the applicability threshold for glass manufacturing furnaces should be based on a unit's design production capacity instead of the proposed applicability criteria (*i.e.,* units that directly emit or have the potential to emit 100 TPY or more of NO_X). The commenter stated that the production capacity for glass manufacturing furnaces is a more relevant basis for applicability and would focus the EPA analysis on cost-effective regulations.

Response: During the EPA's development of the proposed emissions limits, the EPA reviewed the applicability provisions in various state RACT NO_X rules, air permits, consent decrees, and Federal regulations applicable to glass manufacturing furnaces. Most of these applicability provisions were expressed in terms of actual emissions or PTE. Given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA finds that applicability criteria based on emissions or potential to emit are the most appropriate way to capture higher-emitting glass manufacturing furnaces that contribute NO_X emissions to downwind receptors.

Emissions Limitations and Rationale

The EPA is finalizing the proposed NO_X emissions limits for furnaces within the Glass and Glass Product Manufacturing industry, except that for flat glass manufacturing furnaces the EPA is finalizing an emissions limit slightly lower than the limit we had proposed, based on a correction to a factual error in our proposal. For further discussion of the basis for the form and level of the final emissions limits, see the proposed rule, 87 FR 20036, 20146 (April 6, 2022) (discussing EPA review of state RACT rules, NSPS, and other regulations applicable to the Glass and Glass Product Manufacturing industry). Several comments supported the EPA's effort to regulate sources within the Glass and Glass Product Manufacturing industry but also requested that the EPA establish more stringent emissions limits for this industry.

Comment: One commenter stated that NO_X emissions from the Glass and Glass Product Manufacturing industry are not currently subject to any Federal NSPS and that the industry is expected to grow in the coming years. The commenter stated that while the EPA's proposed limits on glass furnaces fell within the ranges of limits required by various states and air districts, they fell at the weakest levels within those ranges. For example, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for container glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1 to 4 lb/ton. Similarly, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for pressed/blown glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1.36 to 4 lb/ton, and that EPA had proposed a 9.2 lb/ton NO_X emissions limit for flat glass manufacturing furnaces, while state NO_X emissions limits for these emissions units range from 5–9.2 lb/ton. The commenter urged the EPA to establish emissions limits lower than those the EPA had proposed.

Response: The EPA is finalizing the emissions limits for affected units in the glass and glass product manufacturing industry as proposed for all but flat glass manufacturing furnaces, for which the EPA is finalizing a slightly lower emissions limit to reflect a correction to a factual error in our proposal. During the EPA's development of the proposed emissions limits, the EPA reviewed the control requirements or recommendations and related analyses in various RACT NO_X rules, air permits, Alternative Control Techniques (ACT) documents, and consent decrees to determine the appropriate NO_X emissions limits for the different types of glass manufacturing furnaces. Based on these reviews and given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA has concluded that it is appropriate to finalize the emissions limits for this industry as proposed, except for the limit proposed for flat glass manufacturing furnaces. For flat glass manufacturing furnaces, the EPA had proposed a NO_X emissions limit of 9.2 pounds (lbs) per ton of glass pulled but is finalizing a limit of 7.0 lbs/ton of glass pulled on a 30-day rolling average basis. This is based on our review of specific state RACT NO_X regulations that contain a 9.2 lbs/ton limit averaged over a single day but contain a 7.0 lbs/ton limit over a 30-day averaging period. This change aligns the final limit for flat glass manufacturing furnaces with the correct averaging time and is consistent with both the state RACT regulations that we reviewed [389] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule.

The EPA acknowledges that NO_X emissions from some glass manufacturing furnaces are subject to control under other regulatory programs, such as those adopted by states to meet CAA RACT requirements, and that some of these programs have implemented more stringent emissions limits than those the EPA is finalizing in these FIPs. However, as noted in the preamble to the proposed rule and related TSD, many OTR states do not establish specific NO_X emissions limits for glass manufacturing sources.[390] *See* 87 FR 20146. In addition to state RACT rules, air permits, ACT documents, and consent decrees applicable to this industry, the EPA reviewed reports and recommendations from the National Association of Clean Air Agencies (NACAA), the European Union Commission, and EPA's Menu of Control Measures (MCM) to identify potentially available control measures for reducing NO_X emissions from the glass manufacturing industry. The EPA also reviewed permit data for existing glass manufacturing furnaces to identify control devices currently in use at these sources. Based on these reviews, we find that the final emissions limits for the Glass and Glass Product Manufacturing industry provided in Table VI.C.3–1 generally reflect a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

TABLE VI.C.3–1—SUMMARY OF FINALIZED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lbs/ton of glass produced, 30 operating-day rolling average)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

Alternative Emissions Standards During Periods of Start-Up, Shutdown, and Idling

Comment: Numerous commenters urged the EPA to provide additional flexibilities, alternative NO_X emissions limits, or exceptions to the NO_X emissions limits for glass manufacturing furnaces during periods of startup, shutdown and idling. Commenters requested that the EPA consider excluding days with low glass pull (*e.g.,* abnormally low production rate), furnace start-up days, furnace maintenance days, and malfunction days from the definition of "operating day" to allow for exclusion of these days from the calculation of an emissions unit's 30-operating day rolling average emissions. The commenters argued that because the glass furnace temperature is much lower during these periods than they are during normal operating conditions, it would be technologically infeasible to equip furnaces with NO_X control devices including SCR. Commenters also stated that because control equipment cannot be operated during these periods without damaging the equipment, it would be very difficult or impossible to meet the proposed NO_X limits during these periods.

Response: After review of the comments received and the EPA's assessment of current practices within

[389] For example, Pennsylvania's RACT NO_X emission limits for flat glass furnaces are 7.0 lbs of NO_X per ton of glass produced on 30-day rolling average. *See* Title 25, Part I, Subpart C, Article III, Section 129.304, available at *https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements.*

[390] See Proposed Non-EGU Sectors TSD at 56, EPA–HQ–OAR–2021–0668–0145.

the glass manufacturing industry, the EPA is establishing provisions for alternative work practice standards and emissions limits that may apply in lieu of the emissions limits in § 52.44(c) during periods of start-up, shutdown, and idling. The emissions limits for glass melting furnaces in § 52.44(c) do not apply during periods of start-up, shutdown, and/or idling at affected units that comply instead with the alternative requirements for start-up, shutdown, and/or idling periods specified in § 52.44(d), (e), and/or (f), respectively. The EPA has modeled these alternative requirements that apply during startup, shutdown, and idling to some extent on State RACT requirements identified by commenters.[391] These alternative work practice standards adequately address the seven criteria that the EPA has recommended states consider when establishing appropriate alternative emissions limitations for periods of startup and shutdown.[392] We provide a more detailed evaluation of these provisions in the TSD supporting this final rule.

Specifically, each owner or operator of an affected unit seeking to comply with alternative work practice standards in lieu of emissions limits during startup or shutdown periods must submit specific information to the Administrator no later than 30 days prior to the anticipated date of startup or shutdown. The required information is necessary to ensure that the furnace will be properly operated during the startup or shutdown period, as applicable. The final rule establishes limits on the number of days when the owner or operator may comply with alternative work practice standards in lieu of emissions limits during startup and shutdown, depending on the type of glass furnace. Additionally, the owner or operator must maintain operating records and additional documentation as necessary to demonstrate compliance with the alternative requirements during startup or shutdown periods. For startups, the owner or operator must place the emissions control system in operation as soon as technologically feasible to minimize emissions. For shutdowns, the owner or operator must operate the emissions control system whenever technologically feasible to minimize emissions.

For periods of idling, the owner or operator of an affected unit may comply with an alternative emissions limit calculated in accordance with a specific equation to limit emissions to an amount (in pounds per day) that reflects the furnace's permitted production capacity in tons of glass produced per day. Additionally, the owner or operator must maintain operating records as necessary to demonstrate compliance with the alternative emissions limitations during idling periods. During idling, the owner or operator must operate the emissions control system to minimize emissions whenever technologically feasible.

All-Electric Glass Furnaces

The EPA solicited comment on whether it is feasible or appropriate to phase out and retire existing glass manufacturing furnaces in the affected states and replace them with more energy efficient and less emitting units like all-electric melter installations. The EPA also requested comment on the time needed to complete such a task. All-electric melters are glass melting furnaces in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass.[393] The EPA received numerous comments from the glass industry regarding their concerns with replacing an existing glass manufacturing furnace with an all-electric melter. The commenters stated that various operational restrictions present within all-electric furnaces prevent these units from being implemented throughout the industry, including limited glass production output, reduced glass furnace life, and increased glass plant operating cost due to high levels of electric current usage. Based on the EPA's review of comments submitted on this issue, the EPA has decided not to establish any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time. We provide in the following paragraphs a summary of the comments and the EPA's responses thereto.

Comment: One commenter stated that the lifetime of an all-electric glass melting furnace is only about three to five years before it must be rebricked, compared to well-maintained natural gas or hybrid furnace that may be operated continuously for as long as fifteen to twenty years between rebricking events. The commenter also states that electric furnaces for manufacture of glass containers are limited to a maximum glass production of about 120 tons per day, which is a stark contrast to large natural gas fired glass melting furnaces, which are capable of producing over 400 tons of glass per day. The commenter also stated that the cullet percentage is greatly reduced in all-electric furnaces which increases energy consumption in the affected facility.

Response: At proposal, the EPA solicited comment on whether it is feasible or appropriate for owners or operators of existing glass manufacturing furnaces to phase out and retire their units and replace them with less emitting units like all-electric furnace installations. As explained in the Final Non-EGU Sectors TSD, over the last few decades the demand for flat, container, and pressed/blown glass has continued to grow annually. Nitrogen oxides remain one of the primary air pollutants emitted during the production and manufacturing of glass products. However, no current Federal CAA regulation controls NO_X emissions from the industry on a category-wide basis.[394] Therefore, the glass manufacturing industry has conducted various pollution prevention and research efforts to help identify preferred techniques for the control of NO_X. Some of these studies revealed recent trends to control NO_X emissions in the glass industry, including the use of all-electric glass furnaces. We understand based on the comments received from the glass manufacturing industry that significant differences exist in the design, configuration, age, and replacement cost of glass furnaces and in the feasibility of controls and raw material compositions. These differences as well as the production limitations present with all-electric furnaces create difficulties in implementing all-electric furnaces across the industry while keeping up with glass product demands. Therefore, the EPA is not mandating any requirement for owners or operators of existing glass manufacturing furnaces to replace their units with all-electric furnaces.

Combustion Modification and Post-Combustion Modification Control Devices

According to the EPA's "Alternative Control Techniques Document—NO_X Emissions from Glass

[391] See Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305–129.307 (effective June 19, 2010), available at *https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/chap129toc.html&d=reduce* and San Joaquin Valley Unified Air Pollution Control District, Rule 4354, "Glass Melting Furnaces," sections 5.5–5.7 (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf.*

[392] See 80 FR 33840, 33914 (June 12, 2015) (identifying the EPA's recommended criteria for developing and evaluating alternative emissions limitations applicable during startup and shutdown).

[393] *See* definitions in 40 CFR part 60, subpart CC.

[394] See Final Non-EGU Sectors TSD.

Manufacturing," [395] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. At proposal, the EPA solicited comments on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize these combustion modifications to add or operate a post-combustion modifications control device like SNCR or SCR to further improve their NO_X removal efficiency. The EPA received numerous comments from the glass industry that detailed the differences present in glass furnace designs, operations and finished product that influenced the type of combustion modification or post-combustion modification control device that is feasible for such unit. Several commenters have requested that the EPA focus on establishing an emissions limit rather than specifying the use of a particular control technology given the significant differences across glass furnaces. As a result of the comments received, the EPA is not specifically requiring affected units to install combustion modification and post-combustion controls to meet the finalized emissions limits. The EPA is finalizing the emissions limits as proposed, which may be met with combustion modifications (*e.g.,* low-NO_X burners, oxy-firing), process modifications (*e.g.,* modified furnace, cullet preheat), and/or post-combustion controls (SNCR or SCR) and thus provide sources some flexibility to choose the control technology that works best for their unique circumstances.

Comment: Multiple commenters responded to EPA's request for comments by stating it is unnecessary and unhelpful for the proposed rule to specify use of particular post-combustion control device. The commenters note that various flat glass furnaces have a variety of combustion and post-combustion control options. Each furnace is different in its design, operations, and finished product produced. The commenters state that it is more appropriate for EPA to establish an emissions limit in the proposed rule than it is for the EPA to specify use of a particular control technology.

Response: In response to these comments, the EPA is not establishing any requirements for affected units to install specific control technologies to meet the emissions limits. The EPA is finalizing the limits as proposed to offer sources some flexibility to choose the control technology that works best for their unique circumstances.

Compliance Assurance Requirements

The EPA proposed to require owners or operators of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces to install, calibrate, maintain and operate a CEMS for the measurement of NO_X emissions discharged. The EPA also solicited comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. The EPA received numerous comments from the glass industry expressing concern with any requirement to use CEMS at affected units. After review of the comments received and EPA's assessment of practices conducted within the glass manufacturing industry, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnaces to demonstrate compliance through annual testing or use CEMS, or similar alternative monitoring system data in lieu of a performance test. The EPA is also establishing recordkeeping provisions that require owners or operators of affected units to conduct parametric monitoring of fuel use and glass production during performance testing to assure continuous compliance on a 30-operating day rolling average.

Comment: Commenters representing the glass industry stated that a requirement to install and operate CEMS would present significant costs and technical complexities in a situation where emissions can be effectively monitored using stack testing rather than continuous monitoring. Commenters also objected to the EPA's proposal to require CEMS together with semi-annual stack testing. Commenters stated that a requirement to both operate CEMS and conduct semi-annual testing would be unnecessary and excessive and would not provide commensurate benefit unless a facility's emissions are near or above the proposed emissions limit. Commenters requested that owners or operators of affected units be allowed to use alternative monitoring systems, *e.g.,* parametric emissions monitoring. The commenters stated that parametric monitoring requires less initial and ongoing manpower requirements, has lower capital and operating costs than CEMS, does not require spare parts, and is accurate over a mapped range.

Response: The EPA is establishing compliance assurance requirements that provide flexibility to owners or operators of affected units. Compliance with the emissions limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season.

5. Boilers at Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Iron and Steel and Ferroalloys Manufacturing, and Metal Ore Mining facilities

Applicability

The EPA is finalizing regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing industry, Basic Chemical Manufacturing industry, Petroleum and Coal Products Manufacturing industry, Pulp, Paper, and Paperboard Mills industry, and the Metal Ore Mining industry that apply to boilers that have a design capacity of 100 mmBtu/hr or greater. The Non-EGU Screening Assessment memorandum developed in support of Step 3 of our proposal identified emissions from large boilers in certain industries (*i.e.,* those projected to emit more than 100 tpy of NO_X in 2026) as having adverse impacts on downwind receptors. As discussed in the proposed rule, we developed applicability criteria for boilers based on design capacity (*i.e.,* heat input), rather than on potential emissions, because use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. In this final rule, we are establishing the heat input-based applicability criteria described in our proposal, with some adjustments as explained further in this section. Additionally, we have determined that boilers meeting these applicability

[395] EPA, Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing, EPA–453/R–94–037, June 1994.

criteria exist within the following five industries: Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and Iron and Steel Mills and Ferroalloy Manufacturing.

As we explained in the proposed rule, the potential emissions from industrial boilers with a design capacity of 100 mmBtu/hr or greater burning coal, residual or distillate oil, or natural gas can equal or exceed the 100 tpy threshold that we used to identify impactful boilers within the Non-EGU Screening Assessment memorandum. We are finalizing NO_X emissions limits that apply to boilers with design capacities of 100 mmBTU/hr or greater located at any of the five identified industries in any of the 20 covered states with non-EGU emissions reduction obligations. In response to comments on our proposed rule, however, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year and provisions for EPA approval of alternative emissions limits on a case-by-case basis, where specific criteria are met. Additionally, only boilers that combust, on a BTU basis, 90 percent or more of coal, residual or distillate oil, natural gas, or combinations of these fuels are subject to the requirements of these final FIPs.

The EPA has determined that boilers meeting the applicability criteria of this section exist within the five industrial sectors identified in Table VI.C.5–1:

TABLE VI.C.5—1: NON-EGU INDUSTRIES WITH LARGE BOILERS AND ASSOCIATED NAICS CODES

Industry	NAICS code
Basic Chemical Manufacturing	3251xx
Petroleum and Coal Products Manufacturing	3241xx
Pulp, Paper, and Paperboard Mills	3221xx
Iron and Steel and Ferroalloys Manufacturing	3311xx
Metal Ore Mining	2122xx

Comment: Several commenters requested that the EPA establish PTE-based applicability criteria for boilers as it had proposed to do for other non-EGU sectors and stated that using heat input as the basis for determining applicability would result in low-emitting boilers being subject to the final rule's control requirements. Commenters stated that the EPA should provide a low-use exemption for infrequently run units because these units produce a lower amount of emissions.

Response: The EPA is finalizing applicability criteria for boilers based on boiler design capacity for a number of reasons. First, Federal emissions standards applicable to boilers[396] and all of the state RACT rules that we reviewed contain applicability criteria based on boiler design capacity. Second, as explained in the Final Non-EGU Sectors TSD, most boilers with design capacities of 100 mmBTU/hr or greater that are fueled by coal, oil, or gas have the potential to emit 100 tpy or more of NO_X. Thus, use of a boiler design capacity of 100 mmBtu/hr for applicability purposes reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. Finally, use of a boiler's design capacity for applicability purposes facilitates applicability determinations given that a boiler's design capacity is, in most cases, clearly indicated by the manufacture on the unit's nameplate.

In response to the comments expressing concern that infrequently-operated boilers would be captured by the EPA's proposed applicability criteria, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. Such boilers will be exempt from the emissions limits in these FIPs provided they operate less than 10 percent per year, on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years, but will have recordkeeping obligations. The EPA finds it appropriate to exempt such low-use boilers from the emissions limits in this final rule because the amount of air pollution emitted from a boiler is directly related to its operational hours, and installation of controls on infrequently operated units results in reduced air quality benefits.

Comment: Commenters asked whether the EPA's proposed emissions limits for boilers would apply to emissions units that burn fuels other than coal, residual or distillate oil, or natural gas. For example, one commenter stated that some biomass boilers start up by co-firing oil or gas and that some NO_X controls such as low-NO_X burners (LNB) cannot be used on biomass boilers. The commenter requested clarification on whether boilers burning biomass would be covered by the EPA's proposed requirements. Other commenters noted that some industrial boilers burn natural gas in conjunction with other gaseous fuels, such as hydrogen/methane off-gas and vent gas from various on-site processes, and may not be able to meet the EPA's proposed 0.08 lb/mmBtu NO_X emissions limit for boilers burning natural gas. One commenter stated that it operated a boiler that burns hazardous waste and is subject to 40 CFR part 63, subpart EEE, National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors, and that this boiler uses natural gas for start-up and at other times to stabilize operations but also combusts other fuels such as liquid waste. The commenter asserted that such boilers should not be covered by the final rule.

Response: In recognition and consideration of comments received on our proposal, the EPA is finalizing requirements for boilers that apply only to boilers burning 90 percent or more coal, residual or distillate oil, or natural gas or combinations of these fuels on a heat-input basis. Public commenters presented information indicating that the burning of fuels other than coal, residual or distillate oil, or natural gas at levels exceeding 10 percent may interfere with the functions of the control technologies that may be necessary to the meet the final rule, like SCR. The EPA does not have sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost. Therefore, boilers that burn greater than 10 percent fuels other than coal, residual or distillate oil,

[396] *See, e.g.,* 40 CFR 60.44b (subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements of this final rule.

Comment: Some commenters claimed that the EPA cannot include emissions limits for boilers that burn combinations of coal, residual or distillate oil, and natural gas, because the EPA did not propose limits for such boilers. Other commenters suggested it would be appropriate to establish emissions limits for such boilers as long as the EPA provides criteria for establishing such emissions limits.

Response: The EPA disagrees with the claim that boilers burning combinations of coal, residual or distillate oil, or natural gas cannot be covered by the final FIP because the EPA did not propose specific emissions limits for these boilers and agrees with commenters who stated that the EPA's proposed emissions limits can be extended to such boilers provided the EPA provides criteria for doing so. The applicability criteria in the final rule cover boilers burning combinations of coal, residual or distillate oil, or natural gas and include a methodology for determining the emissions limits for such units based on a simple formula that correlates the amount of heat input expended while burning each fuel with the corresponding emissions limit for that particular fuel. For example, a boiler with a heat input of 85 percent natural gas and 15 percent distillate oil would be subject to an emissions limit derived by multiplying the natural gas emissions limit by 0.85 and adding to that the distillate oil emissions limit multiplied by 0.15. Thus calculated, the NO_X emissions limits for boilers burning combinations of coal, residual or distillate oil, or natural gas are consistent with the NO_X emissions limits identified in our proposed rule for each of these individual fuels.

Emissions Limitations and Rationale

The EPA is finalizing all of the proposed NO_X emissions limits for industrial boilers and adding a formula for calculating emissions limits for multi-fueled units as shown in Table VI.C.5–2. The emissions limits apply to boilers with design capacities of 100 mmBtu/hr or greater located at any of the five industries identified in Table II.A–1 within any of the 20 states covered by the non-EGU requirements of this final rule.

TABLE VI.C.5–2—NO_X EMISSIONS LIMITS FOR BOILERS >100 mmBtu/hr

[Based on a 30-day rolling average]

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20.
Residual oil	0.20.
Distillate oil	0.12.
Natural gas	0.08.
Multi-fueled unit	Limit derived by formula based on heat input contribution from each fuel.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided in the Final Non-EGU Sectors TSD.

Comment: Some commenters noted that many boilers are already subject to other state and Federal controls, and that programs such as RACT, NSR, BACT, NSPS, and maximum achievable control technology (MACT) are all achieving emissions reductions from boilers.

Response: The EPA acknowledges that some affected units may already be meeting the emissions limits established in this rule as a result of controls installed to comply with other regulatory programs, such as the CAA's RACT requirements. However, emissions from the universe of boilers subject to the applicability requirements of this final rule are not being uniformly reduced by these programs to the same extent that the limits we are adopting will require, nor for the same reason, which is to mitigate the impact of emissions from upwind sources on downwind locations that are experiencing air quality problems. The EPA has determined that the limits we are finalizing in this action are readily achievable and are already required in practice in many parts of the country.

Regarding RACT controls, some of the sources covered by the final rule are not subject to RACT requirements because RACT is only applicable to sources located in ozone nonattainment areas and in the OTR, and many sources covered by the final rule are not located within such jurisdictions. Regarding sources that are subject to RACT, we note that unlike RACT requirements applicable to sources of VOCs, where a majority of such sources are covered by state RACT rules adopted to conform with uniform "presumptive" limits contained within the EPA's Control Technique Guidelines (CTGs), in most cases presumptive NO_X emissions limits have not been established for industrial sources of this pollutant. In light of this, NO_X RACT requirements are primarily determined on a state-by-state basis and exhibit a range of stringencies as determined by each state. Additionally, RACT requirements tend to become more stringent with the passage of time as existing control options are improved, and new options become available. Thus, older RACT determinations may not be as stringent as more recent determinations made for similar equipment types. As noted in our proposal, we based our NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired industrial boilers on RACT limits that are already in place in many areas of the country.

Regarding NSR control requirements, we note that the NSR program was created by the 1977 amendments to the CAA and applies only to new or modified stationary sources. Many of the boilers covered by the applicability requirement of this final rule were initially installed or last modified prior to 1977 and have not undergone NSR analysis, such as a BACT analysis for sources located within an attainment area or a LAER analysis for sources located within nonattainment areas. Additionally, BACT and LAER determinations made many years ago are not likely to be as stringent as more recent determinations.

Regarding NSPS requirements, 40 CFR part 60, subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, contains NO_X emissions limits for boilers with capacities of 100 mmBTU/hr or greater that were constructed or modified after June 19, 1984, and so boilers constructed or modified prior to that date are not subject to its requirements. Additionally, the limits for coal, residual or distillate oil, and gas-fired units are not as stringent as more recent limits adopted by states pursuant to RACT control obligations.

Lastly, MACT controls are primarily designed to reduce emissions of hazardous air pollutants, not to reduce NO_X emissions. We anticipate the MACT program's boiler tune-up requirement should reduce NO_X emissions to some extent, but not to the extent that compliance with the limits adopted within this final rule will achieve.

Comment: One commenter noted that a 2017 OTC survey found that boilers, including those used in the paper products, chemical, and petroleum industries, are already required to achieve more stringent limits, and pointed to limits for distillate oil that are lower than what the EPA considered in developing the proposal. The commenter also noted that California's South Coast Air Quality Management District has adopted a facility-wide NO_X emissions limit of 0.03 lb/mmBtu at petroleum refineries. The commenter noted that CEMs data shows a residual oil-fired boiler at the Ravenswood Steam Plant in New York achieves an average NO_X emissions rate of 0.0716 lb NO_X/MMBtu and that CEMS data shows that a gas-fired boiler in Johnsonville, Tennessee, achieves an average NO_X emissions rate of 0.0058 lb NO_X/mmBTU. Regarding coal-fired boilers, the commenter stated that a coal boiler at the Ingredion Incorporated Argo Plant in Illinois achieves an average NO_X emissions rate of 0.1153 lb NO_X/MMBtu with selective non-catalytic control technology, and the Axiall Corporation facility in West Virginia achieves a 0.1162 lb/mmBtu using low-NO_X burner technology with overfire air. The commenter also noted that more than half of the gas-fired boilers included in the air markets program database already emit NO_X at rates below the EPA's proposed emissions rate, and that the RACT/BACT/LAER Clearinghouse (RBLC) shows more stringent limits for gas boilers than the limits the EPA proposed, with many facilities being required to meet a NO_X limit of less than 0.0400 lb/mmBtu.

Response: The EPA's intent was not to set the NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired boilers to match the lowest levels required elsewhere by state or local authorities, but rather to establish limits that are commensurate with broadly applicable RACT limits currently in place in a number of states as noted within our proposal. The limits we selected were not the most stringent of the state RACT rules we reviewed but were relatively close to that value. We did not select the most stringent limits because such limits may reflect case-specific technological and economic feasibility considerations that do not apply more broadly across the industry. Furthermore, although the EPA acknowledges that some industrial boilers powered by coal, residual or distillate oil, natural gas, or combinations of these fuels can meet very low NO_X emissions limits as noted by the commenter, it is unlikely that all such units could meet these limits given case-specific considerations such as boiler design and operation, some of which limit the types of control technology that may be available to a particular unit.

a. Coal-Fired Industrial Boilers

As we proposed, coal-fired industrial boilers subject to the applicability requirements of this section are required to meet a NO_X emissions limit of 0.2 lb/mmBtu on a 30-day rolling average basis. Various forms of combustion and post-combustion NO_X control technology exist that should enable most facilities to retrofit with equipment to meet this emissions limit. As we explained in our proposal, many states containing ozone nonattainment areas or located within the OTR have already adopted RACT emissions limits similar to or more stringent than the limits in this final rule, and most of those RACT limits apply statewide and extend to boilers located at commercial and institutional facilities, not just to boilers located in the industrial sector.

Comment: One commenter noted that the coal-fired boilers it operates already use combustion controls to reduce NO_X emissions and contended that the effectiveness of SNCR on these boilers is unknown but would likely be on the low end of the control effectiveness range because they experience variable loads, which would compromise the proper functioning of an SNCR control system. The commenter stated that the only way their coal-fired boilers would be able to comply with the EPA's proposed NO_X limit would be to install SCR. The commenter added that for coal-fired industrial boilers with a heat input rating of 100 MMBtu/hr or more, a review of the available RBLC records indicates that out of the 23 RBLC entries identified, nine units (less than half) were subject to an emissions limit at or below 0.2 lb/mmBtu, and eight of these nine units were equipped with SNCR. The commenter stated that based on a review of the available data in the RBLC and given the technical difficulties and low control efficiencies when applying SNCR to swing boilers, the EPA's proposed limit for coal firing does not appear achievable for industrial coal-fired boilers that experience load swings unless SCR is installed. Other commenters stated that while there have been recent advancements in SNCR technology, such as the setting up of multiple injection grids and the addition of sophisticated CEMs-based feedback loops, implementing SNCR on industrial load-following boilers continues to pose several technical challenges, including lack of achievement of optimal temperature range for the reduction reactions to successfully complete, and inadequate reagent dispersion in the injection region due to boiler design which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.,* large ammonia slip). The commenter noted that at least one pulp mill boiler had to abandon its SNCR system due to problems caused by poor dispersion of the reagent within the boiler, and that SNCR has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads.

Response: To the extent the commenter's concerns pertain primarily to SNCR control technology, we note that the final rule does not mandate the use of any particular type of control technology and that other types of control equipment such as SCR should be examined as a means for meeting the final emissions limits. The EPA acknowledges that some coal-fired industrial boilers subject to this section of the final rule may need to install SCR to meet the NO_X emissions limits. This is reflected in our evaluation of costs for the non-EGU sector contained within the Non-EGU Screening Assessment memorandum and the cost calculations for the final rule discussed in section V and the *Memo to Docket—Non-EGU Applicability Requirements and Estimate Emissions Reductions and Costs.* We note that although the RBLC contains information on emissions limits and control technology for some units, it only provides information on a relatively small number of units subject to NO_X emissions limits and operating NO_X controls. Additionally, our final rule provides an exemption for units that operate infrequently (*i.e.,* "low-use boilers"), and also allows a facility owner or operator to submit a request for a case-by-case alternative emissions limit in cases where compliance with the emissions limit in this final rule is technically impossible or would result in extreme economic hardship. We note that non-EGU boilers share many similarities with EGU boilers, many of which already operate SCR to control NO_X emissions or will be required to install and operate SCR systems under the requirements for EGUs contained in this final rule. Lastly, we note that information collected during the development of updates to the EPA's MACT requirements for industrial, commercial, and institutional (ICI) boilers indicates that over 150 ICI boilers have installed SCR control systems to reduce their NO_X emissions. This information is available in the docket for this final rule.

All affected units must install and operate NO_X control equipment as necessary to meet the applicable emissions limits in the final rule, except that if the owner or operator requests, and the EPA approves, a case-by-case emissions limit based on a showing of technical impossibility or extreme economic hardship, the affected unit would be required to comply with the EPA-approved case-by-case emissions limit instead.

b. Residual or Distillate Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. We proposed a NO_X emissions limit of 0.2 lb/mmBtu [397] for residual oil-fired boilers and proposed a NO_X emissions limit of 0.12 lb/mmBtu for distillate oil-fired boilers. We are finalizing both limits as proposed, based on a 30-day rolling average. As with coal-fired industrial boilers, a number of combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet these emissions limits, and the Final Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits in this final rule. There are relatively few boilers fueled by residual or distillate oil within the industries affected by this final rule that meet the applicability criteria of this section, and we received relatively few comments regarding our proposed emissions limits for them.

c. Natural Gas-Fired Industrial Boilers

We proposed a NO_X emissions limit of 0.08 lb/mmBtu based on a 30-day rolling average for natural gas-fired boilers meeting the applicability criteria of this section, and we are finalizing this emissions limit and averaging time as proposed. As explained in our proposal, numerous combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet this emissions limit. Additionally, many states have already adopted emissions limits similar to the emissions limit in this final rule, and some natural gas-fired industrial boilers may be able to meet the 0.08 lb/mmBtu emissions limit by modifying existing NO_X control equipment installed to meet the requirements in 40 CFR 60.44b (subpart Db of 40 CFR part 60, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), which already requires that natural gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu.

Compliance Assurance Requirements

We proposed compliance provisions for boilers subject to the requirements of this section similar to the emissions monitoring requirements found in 40 CFR 60.45 (subpart D of 40 CFR part 60, Standards of Performance for Fossil-Fuel-Fired Steam Generators). Those requirements include, among other provisions, the performance of an initial compliance test and installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the emissions limit in this final rule. We received a number of comments on this portion of our proposal and provide responses to some of these comments in the following paragraphs. Our full responses to comments are provided in the response to comments document included in the docket for this action.

Comment: A number of commenters stated that CEMS monitoring is too expensive and unnecessary for ensuring compliance with the emissions limits for boilers and requested that alternative monitoring techniques be allowed.

Response: The EPA acknowledges that the installation and operation of CEMs systems is more expensive than other monitoring techniques and may not be necessary for smaller sized boilers that typically produce less emissions than larger ones. In response to these comments, we have modified the monitoring requirements in the final rule such that boilers rated with heat-input capacities less than 250 mmBTU/hr can demonstrate compliance by conducting an annual stack test as an alternative to monitoring using a CEMs system and by complying with the provisions of a monitoring plan meeting specific criteria that enables the facility owner or operator to demonstrate continuous compliance with the emissions limits of this final rule.

Comment: One commenter stated that the proposed reporting obligations require the submittal of excess emissions reports, continuous monitoring, and quarterly emissions reports. The commenter suggested that since the NO_X emissions standards only apply during the ozone season (May 1–September 30), the reporting requirements should only apply during the second and third quarters of the year and should require that only emissions and monitoring data from this time period be included in these reports.

Response: In response to these comments, the EPA is finalizing recordkeeping, monitoring, and reporting requirements that are designed to ensure compliance with the applicable emissions limits only during the ozone season. Additionally, the final rule requires annual reports rather than the proposed quarterly reports as annual reports are adequate to determine compliance with the emissions limits during the ozone season.

Comment: A number of commenters stated that some of their boilers that may potentially be subject to a final FIP already have a NO_X CEMS installed and requested that the EPA clarify whether a 30-day initial compliance test is required in such cases.

Response: The EPA's final rule provides that in instances where a boiler meeting the applicability requirements of this section has already installed a NO_X CEMs that meets the requirements for such equipment located within 40 CFR 60.13 or 40 CFR part 75, Continuous Emissions Monitoring, pursuant to a federally enforceable requirement, a 30-day initial compliance test is not required.

Comment: One commenter stated that § 52.45(d) of the EPA's proposed rule included requirements to complete an initial 30-day compliance test within 90 days of installing pollution control equipment but did not specify whether the test must be complete prior to the May 1, 2026, ozone season or by some later date.

Response: In response to this comment, the EPA is finalizing provisions requiring that initial compliance tests occur prior to the May 1, 2026 compliance date.

6. Municipal Waste Combustors

Applicability

The EPA is finalizing regulatory requirements that apply to municipal solid waste combustors located in a state subject to the non-EGU requirements of this final rule (*i.e.,* the 20 states with linkages that persist in 2026 as identified in section II.B) and

[397] Section 52.45(c) of the regulatory text in our proposed rule identified a proposed emissions limit of 0.15 lb/mmBtu for residual oil-fired boilers, but the emissions limit that we intended to propose for this equipment and discussed both in the preamble to the proposed rule and in the TSD supporting the proposed rule was 0.20 lb/mmBtu.

that combust greater than or equal to 250 tons per day of municipal solid waste ("affected units"). *See* 40 CFR 52.46(d) for guidelines on calculating municipal waste combustor unit capacity. This applicability threshold was supported by commenters and is consistent with the applicability criteria in 40 CFR part 60, subpart Eb, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Large Municipal Waste Combustors. State RACT rules for MWCs and the OTC MWC report similarly define large MWC units as units with a combustion capacity greater than or equal to 250 tons per day.

Across the 20 states subject to the non-EGU requirements, this applicability threshold captures 28 MWC facilities with a total of 80 affected units. The identified affected units include mass burn waterwall units, mass burn rotary waterwall units, refuse derived fuel (RDF) units, and one CLEERGAS™ ("Covanta Low Emissions Energy Recovery Gasification") modular system.[398] The EPA analyzed actual emissions from the facilities captured by this threshold and found that on average, a unit with a design capacity of 250 tons per day has a PTE of approximately 138 tons per year,[399] which is similar to the PTE threshold applied to other non-EGU sources under this rulemaking.

Emissions Limitations and Rationale

Based on the available information for this industry, including information provided during the public comment period, the OTC MWC Report, a review of State and local RACT rules that apply to MWCs, and active air permits issued to MWCs, the EPA is finalizing the following emissions limits for municipal solid waste combustors.

TABLE VI.C.6–1—NO_X EMISSIONS LIMITS FOR LARGE MUNICIPAL WASTE COMBUSTORS

NO_X Limit (ppmvd) corrected to 7 percent oxygen	Averaging period
110	24-hour.
105	30-day.

At proposal, the EPA noted that the NO_X limits for large MWCs constructed on or before September 20, 1994 under NSPS subpart Cb are found within Tables 1 and 2 of 40 CFR 60.39b and range from 165 to 250 ppm depending on the combustor design type. The NO_X limits for large MWCs constructed after September 20, 1994 or for which modification or reconstruction is commenced after June 19, 1996 under NSPS subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lb/mmBtu, respectively. In reviewing active air permits for MWCs, the EPA found that most MWCs are meeting emissions limits similar to those reflected in the applicable NSPS.[400]

The EPA also cited the OTC's MWC report that evaluated the emissions reduction potential of large MWCs located in the OTR from two different control levels, one based on a NO_X concentration of 105 to 110 ppm, and another based on a limit of 130 ppm. The OTC MWC report found that a control level of 105 ppmvd on a 30-day rolling average basis and a 110 ppmvd on a 24-hour block averaging period would reduce NO_X emissions from MWCs by approximately 7,300 tons annually, and that a limit of 130 ppmvd on a 30 day-average could achieve a 4,000 ton reduction. The OTR MWC Report noted that at the time of publication, eight MWC units were already subject to permit limits of 110 ppm, seven in Virginia, and one in Florida. In consideration of control costs, the report cited multiple studies evaluating MWCs similar in design to the large MWCs in the OTR and found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced.

To further inform the EPA's consideration of emissions limits for MWCs, the EPA requested comment on the emissions limit and averaging time MWCs should be required to meet, and specifically whether the EPA should adopt emissions rates of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Comment: The agency received several comments regarding emissions limits and averaging time for MWCs. Many commenters asserted that the EPA should set a 24-hour emissions limit no higher than 110 ppm, noting that recent studies have shown that there are a variety of technologies that can help a wide range of MWC types achieve this limit at costs that are significantly below the $7,500/ton cost effectiveness threshold that the EPA identified at proposal. Some commenters confirmed the accuracy of the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 while others stated that the cost of controls is well below $7,500. One commenter asserted that the EPA should set a 24-hour NO_X emissions limit of 50 ppmvd for MWCs, which could be achieved by the installation of SCR technology. Alternatively, the commenters stated that the EPA should set a 24-hour emissions limit no higher than 110 ppm based on less effective, though still widely available, control technology. Although some commenters stated that MWCs should not be included in the rulemaking, no commenters specifically identified units or categories of units that could not achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Response: The EPA recognizes that there have been instances where MWCs have installed SCR and achieved emissions rates of 50 ppmvd on a 24-hr averaging basis and 45 ppmvd on a 30-day rolling averaging basis with cost effectiveness estimates around $10,296/ton to $12,779/ton of NO_X reduced. Given uncertainties pertaining to whether SCR can be installed on all types of MWCs, the EPA has decided not to establish emissions limits as low as 50 ppmvd for MWCs using SCR at this time. However, as generally supported by most commenters, the EPA is finalizing emissions limits of 105 ppmvd at 7 percent oxygen (O_2) on a 30-day rolling average and 110 ppmvd at 7 percent O_2 on a 24-hour block average that apply at all times except during periods of startup and shutdown. The EPA recognizes that the final emissions limits for steady-state operations cannot be achieved during periods of startup, shutdown, and malfunction. This is primarily due to the fact that during periods of startup and shutdown, additional ambient air is introduced into the units, resulting in higher oxygen concentrations. Therefore, the EPA is finalizing provisions applicable during periods of startup and shutdown that do not require correction of CEMS data to 7 percent oxygen but do require that such data be measured at stack oxygen content. This approach is consistent with EPA regulations applicable during startup and shutdown periods for other solid-waste incinerators under the NSPS for Commercial and Industrial Solid Waste Incineration Units. *See* 40 CFR part 60, subparts CCCC and DDDD.

[398] *See* the Final Non-EGU Sectors TSD for additional information on this inventory.

[399] *See* the Final Non-EGU Sectors TSD for additional information on the calculation of PTE for large MWCs.

[400] For further discussion of the permits reviewed, see the Final Non-EGU Sectors TSD.

Information received from public commenters generally aligned with the results from studies showing that the emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis can be reached using ASNCR or low NO_X technology in addition to SNCR.[401] The EPA recognizes that not all units can implement low NO_X technology, including those using Aireal grate technology, those operating RFD units, and those with rotary combustor units. Of the 80 affected MWC units that the EPA identified, nine units across two facilities are classified as rotary combustors, four units at a single facility are classified as RDF, and no units captured are classified as using Aireal grate technology. One affected unit is classified as CLEERGAS gasification while the remaining 64 affected units are classified as mass burn waterwall combustors, which have not been explicitly identified as units unable to install low NO_X technology. For those units unable to install low NO_X technology or SNCR, the EPA has identified ASCNR as an alternative control technology that has been shown to enable units to achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis, either as a new retrofit technology or as a significant upgrade to existing SNCR. The EPA finds that the availability of ASNCR or SNCR and low NO_X burners provides sufficient flexibility for MWCs to meet the emissions limits in the final rule, especially considering 74 of the 80 affected units already have SNCR installed. Although there is uncertainty on the cost effectiveness of ASNCR for achieving significant NO_X reductions in small MWCs, small MWCs that combust less than 250 tons per day of municipal solid waste are not included in this rulemaking.

While commenters noted discrepancies across cost effectiveness values for specific types of control technology, no commenters specifically indicated that emissions control technology could not be cost effectively installed on large MWCs to achieve an emissions limit of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis. Studies show that these limits can be achieved through a variety of emissions controls, including ASNCR and the addition of low NO_X technology to existing SNCR.[402] Of the 80 MWC units subject to this rule, 55 units already have SNCR installed, 16 units already have SNCR and low NO_X technology installed, and three units already have ASNCR installed. Applying the cost values provided in the OTC's MWC report to the MWC inventory in section 7 of the Final Non-EGU Sectors TSD, the estimated weighted average cost effectiveness of applying advanced SNCR to units with and without existing SNCR and adding low NO_X technology to eligible units with SNCR was found to be approximately $7,929.02/ton.[403] This value is in line with the control technology costs for other non-EGU sectors and the EGU costs associated with this final rule.

Compliance Assurance Requirements

In this final rule, the EPA is establishing compliance requirements for MWCs similar to the NSPS requirements for large MWCs under 40 CFR part 60, subpart Eb. Those requirements include, among other provisions, the performance of an initial performance test and installation of a CEMS. At proposal, the EPA requested comment on whether it would be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under applicable NSPS or other requirements.

Comment: Some commenters noted that all large MWCs are already required to use CEMS to demonstrate compliance with NO_X limits under the NSPS program. These commenters asserted that the EPA should improve electronic reporting requirements beyond current requirements in the NSPS. The commenters suggested that an owner or operator of an MWC subject to a limit under the final rule should be required to report NO_X CEMS data electronically at least annually to the EPA's CEDRI and any other database that the EPA will utilize when considering revisions to the NSPS for large MWCs. The commenters asserted that MWC operators should be required to report NO_X CEMS data to the EPA's Clean Air Markets database, to allow the public access to MWC CEMS data on a large scale for the first time.

Response: The EPA is finalizing provisions that require MWCs subject to the requirements of this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. This is consistent with NSPS requirements for large MWCs under 40 CFR part 60, subparts Ea and Eb, and state RACT rules that are applicable to MWCs in many of the states covered under this rulemaking.[404] Additionally, each emissions unit will be required to conduct an initial performance test. With regard to electronic reporting, the final rule requires performance tests and reports, including CEMS data, to be submitted to CEDRI, as required for all non-EGU industries covered by this final rule.

D. Submitting a SIP

A state may submit a SIP at any time to address CAA requirements that are covered by a FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate. As discussed in this section, states may opt for one of several alternatives that the EPA has provided to take over all or portions of the FIP. However, as discussed in greater detail further in this section, the EPA also recognizes that states retain the discretion to develop SIPs to replace a FIP under approaches that differ from those the EPA has finalized.

The EPA has established certain specialized provisions for replacing FIPs with SIPs within all the CSAPR trading programs, including the use of so-called ''abbreviated SIPs'' and ''full SIPs,'' *see* 40 CFR 52.38(a)(4) and (5) and (b)(4), (5), (8), (9), (11), and (12); 40 CFR 52.39(e), (f), (h), and (i). For a state to remove all FIP provisions through an approved SIP revision, a state would need to address all of the required reductions addressed by the FIP for that state, *i.e.*, reductions achieved through both EGU control and non-EGU control,

[401] The only demonstrated use of low NO_X technology in addition to SNCR at MWC facilities is at Covanta facilities using Covanta's proprietary low NO_X combustion system (LN™). For the purpose of this rule, EPA is assuming Covanta facilities will take advantage of this technology and others will use ASNCR. However, other iterations of low NO_X technology could become available, or facilities could work with Covanta to apply this technology to their units.

[402] *See* OTC MWC Report at 6–7; Trinity Consultants, *Project Report Covanta Alexandria/Arlington, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Trinity Consultants, *Project Report Covanta Fairfax, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Babcock Power Environmental, *Waste to Energy NO_X* Feasibility Study, Prepared for: Wheelabrator Technologies Baltimore Waste to Energy Facility Baltimore, MD (February 20, 2020); White, M., Goff, S., Deduck, S., Gohlke, O., *New Process for Achieving Very Low NO_X, Proceedings of the 17th Annual North American Waste-to-Energy Conference, NAWTEC17* (May 2009); Letter from the State of New Jersey to Michael Klein, In Rreference to Covanta Energy Group, Inc. Essex County Resource Recovery Facility, Newark Annual Stack Test Program (March 14, 2019).

[403] See Final Non-EGU Sectors TSD for more information on these cost effectiveness estimates were generated.

[404] For examples of RACT provisions applicable to MWCs that require CEMS, see Regulations of Connecticut State Agencies section 22a–174–22e; and Virginia Administrative Code section 5–40–6730, subsection (D).

as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this rule may elect to work with EPA under the Tribal Authority Rule to replace the FIP for areas of Indian country, in whole or in part, with a tribal implementation plan or reasonably severable portions of a tribal implementation plan.

Under the FIPs for the 22 states whose EGUs are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with the modifications finalized in this rule, EPA continues to offer ''abbreviated'' and ''full'' SIP options for states. An ''abbreviated SIP'' allows a state to submit a SIP revision that establishes state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaving the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that allow sources in the state to continue to use the EPA-administered trading program through an approved SIP revision, rather than a FIP. In addition, as under past CSAPR rulemakings, states have the option to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2024 control period—through streamlined SIP revisions. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

Comments: Some commenters alleged that by taking this action, EPA is depriving states of the ability to develop SIPs to implement good neighbor obligations for the 2015 ozone NAAQS or from choosing their own compliance strategies. Commenters also claimed that the EPA cannot require states to implement emissions reductions equivalent to the emissions control stringency that the EPA determined at Step 3 if their proposed SIPs are otherwise shown to be adequate to eliminate significant contribution. Other commenters raised concerns that the trading program enhancements for EGUs made it too uncertain what a state could develop as an approvable replacement SIP. At least one commenter argued that the EPA must give states a single, mass-based emissions budget so that they can understand how to replace the FIP with a SIP.

Response: The EPA disagrees that it is depriving States of the opportunity to replace the FIP with a SIP or preventing states from targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP. States have always possessed the authority and the opportunity to revise their SIPs at any point. The EPA has repeatedly emphasized that states are free to develop a SIP revision to replace a transport FIP and submit that to the EPA for approval, and this remains true. *See* 87 FR 20036, 20051 (April 6, 2022); 86 FR 23054, 23062 (April 30, 2021); 81 FR 74504, 74506 (Oct. 26, 2016). In the FIP proposal, as in prior transport actions, the EPA discussed a number of ways in which states could take over or replace a FIP, *see* 87 FR 20036, 20149–51 (section VII.D: ''Submitting A SIP''); *see also id.* at 20040 (noting as one purpose in proposing the FIP that ''this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution''). The EPA provides further guidance on submitting SIPs in this section. If, and when, the EPA receives a SIP submission that satisfies the requirements of CAA section 110(a)(2)(D)(i)(I) and 110(l), the Agency will take action to approve those SIP submissions and withdraw the FIP.

At the outset, we note that the Agency does not anticipate revisiting its findings at Steps 1 or 2 of the transport framework. Those findings establish that the projected baseline anthropogenic emissions from these states contribute to downwind nonattainment or maintenance receptors in 2023, and, for certain states, that contribution continues through 2026. Those represent critical analytical years for downwind areas as they are the last full ozone season before the Moderate and Serious area attainment dates. Those findings, for those years, establish the basis for an upwind state's linkage, from which we proceed to evaluate emissions control opportunities and their implementation at Steps 3 and 4.

We cannot prejudge now whether state submissions to replace the EPA's FIP will be approvable, but we note a number of statutory and implementation considerations states should be aware of if designing a replacement SIP. We have demonstrated that the EPA's transport FIP is adequate to eliminate significant contribution to downwind air quality problems for purposes of the 2015 ozone NAAQS, and that the FIP does not result in overcontrol. The level of reductions required by the FIP therefore provides an important benchmark for states in evaluating the equivalency of possible replacement SIPs. As discussed in more detail in this section, in order to comply with their obligation under CAA section 110(a)(2)(D)(i)(I), we generally anticipate that states seeking to replace the FIP with a SIP that takes an alternative approach would need to establish, at a minimum, an equivalent level of emissions reduction to what the FIP requires at Step 3, and any such replacement SIP will need to comply with CAA section 110(*l*).

The concept of equivalency is important for the state to consider. Under CAA section 110(l), ''the Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment . . . or any other applicable requirement of this chapter.'' Section 110(l) applies to all CAA requirements, including 110(a)(2)(D) requirements relating to interstate transport. The EPA interprets section 110(l) such that states have two main options to make a noninterference demonstration. First, the state could demonstrate that emissions reductions removed from the SIP are replaced with new control measures that achieve equivalent or greater emissions reductions. Thus, a 110(l) analysis would generally need to show that the SIP revision, or, in this case, a potential SIP submission replacing an existing FIP, will not interfere with any area's ability to continue to attain or maintain the affected NAAQS or other CAA requirements. The EPA further has interpreted section 110(l) as requiring such substitute measures to be quantifiable, permanent, and enforceable, among other considerations. For section 110(l) purposes, ''permanent'' means the state cannot modify or remove the substitute measure without EPA review and approval. Second, the state could conduct air quality modeling or develop an attainment or maintenance demonstration based on the EPA's most recent technical guidance to show that, even without the control measure or with the control measure in its modified form, significant contribution from the state would continue to be prohibited as the Act requires. As discussed further in this section, for purposes of interstate ozone transport, such an analysis entails important questions of consistency and equity among states for resolving air quality problems that the EPA would need to carefully evaluate.[405]

[405] For instance, future circumstances in which the receptor or receptors to which a state is linked come fully into attainment or to which the upwind state's linkage drops below 1 percent of the NAAQS would likely not, solely on those grounds, be sufficient to relax transport requirements established by the FIP or justify approving a less stringent SIP. First, the emissions reductions achieved by the FIP are part of the reason that a receptor may come into attainment or a linkage may drop below 1 percent of the NAAQS. Simply

Continued

In the EPA's experience implementing the CAA criteria pollutant program, reductions arising from the good neighbor provision have been critically important to the improvement of air quality in downwind areas struggling with attainment and maintenance of the NAAQS, and states' reliance on good neighbor FIP reductions will need to be taken into account in any replacement SIP. In order for a nonattainment area to be redesignated to attainment, the CAA requires not only that an area attain the standard, but also the Administrator must determine "that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions." CAA section 107(d)(3)(E)(i) and (iii). Many nonattainment areas across the country that have attained various $PM_{2.5}$ and ozone NAAQS have done so in part due to the imposition of Federal good neighbor emissions control measures, and, per CAA section 107(d)(3)(E)(iii), states have specifically relied on the emissions reductions required by those programs in order to be redesignated to attainment. *See, e.g.,* 84 FR 8422, 8425 (March 8, 2019) (noting that "[a]t least 140 EPA final actions redesignating areas in 20 states to attainment with an ozone NAAQS or a fine particulate matter ($PM_{2.5}$) NAAQS—because NO_X is a precursor to $PM_{2.5}$ as well as ozone—have relied in part on the NO_X SIP Call's emissions reductions"); *see also Sierra Club* v. *EPA,* 774 F.3d 383, 397–99 (7th Cir. 2014) (upholding EPA's approval of a redesignation, and specifically EPA's determination that reductions from Federal good neighbor transport trading programs could reasonably be considered "permanent and enforceable" under the statute); *Sierra Club* v. *EPA,* 793 F.3d 656, 665–68 (6th Cir. 2015) (same). States seeking area redesignations are also required under CAA section 107(d)(3)(E)(iv) to develop revisions to their state implementation plans that provide for maintenance of the NAAQS. In so doing, states develop air quality modeling, in which they project future air quality based on emissions inputs that account for enforceable emissions reductions, or states project emissions in the future relative to emissions in an attainment year, showing that the future emissions (which, again, account for on-the-books, enforceable emissions limits) do not exceed emissions in the baseline attainment year. *See* "Procedures for Processing Requests to Redesignate Areas to Attainment," Memo from John Calcagni to EPA Regions, September 4, 1992, at 9. Reductions required by Federal good neighbor programs may therefore also be relied upon by states seeking area redesignations in the context of how states demonstrate that areas will maintain the NAAQS.

We anticipate that air quality in areas struggling to attain and maintain the 2015 ozone NAAQS will improve due to the emissions reductions required by EPA's FIP. We also anticipate that, consistent with EPA's historical experience implementing the NAAQS and acting on state requests for nonattainment area redesignations, emissions reductions associated with EPA's transport FIP for the 2015 ozone NAAQS are likely to be a critical component in those requests for redesignation. Where states have relied and are relying on the FIP's reductions in order to attain and maintain the NAAQS, EPA will look very critically at any replacement SIP that appears to fall short of equivalent emissions reductions—in terms of the level of reductions or the permanence of those reductions.

Finally, we disagree with commenters that the absence of fixed, mass-based emissions budgets for each state make it impossible to replace the FIP with an equivalent SIP. In the case of the trading program enhancements for EGUs, the EPA recognizes that the dynamic budgeting methodology will generally function to impose a continuous incentive on relevant EGUs to continue to implement the emissions control strategies determined at Step 3. Further, the backstop rate and banking recalibration enhancements also are designed to ensure that EGUs implement emissions controls consistent with Step 3 determinations on a continuous basis throughout each ozone season. As explained in section V.D.4 of this document, these aspects of the trading program do not in themselves introduce an overcontrol concern. Nonetheless, consistent with the more general principles discussed in this section with respect to the potential bases on which states may replace the FIP with SIPs, we reserve judgment at this time on whether some future demonstration could successfully establish that revision of the FIP or its replacement with a SIP could be acceptable even if the way that significant contribution is eliminated is through means that differ from the trading program enhancements included for EGUs in this action. As discussed further in this section, a state may choose to withdraw its EGUs from the trading program and instead subject those EGUs to daily emissions rates commensurate with installation and optimization of state-of-the-art combustion and post-combustion controls as the EPA determined at Step 3. Likewise, states are free to explore an alternative set of emissions controls on non-EGU industrial sources (or other sources in the state), so long as they can demonstrate that an equivalent amount of emissions is eliminated. In any case, we need not resolve these questions here. The EPA, in promulgating a FIP, is not obligated to identify each way a state could replace it with a SIP revision. Several options are discussed further in this section, and, as always, EPA Regional Offices will work closely with states who wish to explore these options or other alternatives.

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA is finalizing the option to allow a state to use a similar process to submit a SIP revision establishing allowance allocations for existing EGU units in the state for the second control period of the new requirements, *i.e.,* in 2024, to replace the EPA-determined default allocations. A state must submit a letter to EPA by August 4, 2023, indicating its intent to submit a complete SIP revision by September 1, 2023. The SIP would provide in an EPA-prescribed format a list of existing units within the state and their allocations for the 2024 control period. If a state does not submit a letter of intent to submit a SIP revision, the EPA-determined default allocations will be recorded by September 5, 2023. If a state submits a timely letter of intent but fails to submit a SIP revision, the EPA-determined default allocations will be recorded by September 15, 2023. If a state submits a timely letter of intent

removing emissions control requirements the moment this occurs is illogical, since those reductions are part of the solution by which the attaining air quality was achieved or the linkage was resolved. *See* CAA section 107(d)(3)(E)(iii) (areas cannot be redesignated unless based on permanent and enforceable reductions); *see also Wisconsin,* 938 F.3d at 324–25 (explaining that upwind states are held to a contribution standard, not a but-for causation standard and thus cannot escape good neighbor obligations on the basis that other emissions "cause" the NAAQS to be exceeded). There is a risk of inconsistency and inequity in removing any requirements in this manner in that any increase in emissions that could occur in one upwind state would likely need to be reviewed in relation to the obligations other upwind states would continue to meet. Further, any such relaxation in upwind state requirements could then unreasonably shift the burden for maintaining air quality onto the downwind states where receptors are located. These issues may entail complex state- or case-specific analyses that would need to be evaluated at the time such a SIP revision is submitted; these issues are not ripe for resolution in this action.

followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA received no comments on the proposed option to modify allowance allocations under the Group 3 trading program for EGUs for the 2024 control period through a SIP revision and is finalizing the provisions as proposed.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can modify the EPA-determined default allocations with an approved SIP revision. For the 2025 control period and later, SIPs can be full or abbreviated SIPs. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

In this final rule, the EPA is removing the previous regulatory text defining specific options for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines. These options for expanding trading program applicability through SIP revisions have been available to states since the start of the CSAPR trading programs for small EGUs and since the CSAPR Update for large non-EGU boilers and combustion turbines, and no state has chosen to use the SIP process for this purpose. Additionally, the EPA did not receive comment supporting these expansion options during the comment period for this rule. The EPA is finalizing a methodology for updating the affected EGU portion of the budget in this rule, and the regulatory text defining the applicability expansion to non-EGUs did not include a mechanism for updating the incremental non-EGU portion of a state's budget based on changes over time of the non-EGU fleet; therefore, continuation of the option to expand applicability to certain non-EGUs subject to the NO_X SIP Call would be inconsistent with the trading program as applied to EGUs in this rule.

However, the EPA recognizes that states may seek to include non-EGUs covered in this action in an emissions trading program, subject to important considerations to ensure equivalency in emissions reductions is maintained. While the EPA is not offering specific regulatory text to implement an option to expand the trading program applicability, a state could submit a SIP to expand the CSAPR NO_X Ozone Season Group 3 Trading Program applicability, which the EPA would evaluate on a case-by-case basis. The SIP revision would need to address critical program elements, and include: (1) high-quality baseline data, (2) ongoing Part 75 monitoring, and (3) provisions to update the non-EGU portion of the budget to appropriately reflect changes to the fleet over time.

For states that want to modify the EPA-determined default allocations, the EPA proposed that a state could submit a SIP revision that makes changes only to that provision while relying on the FIP for the remaining provisions of the EGU trading program. This abbreviated SIP option allows states to tailor the FIP to their individual choices while maintaining the FIP-based structure of the trading program. To ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

The SIP submittal deadline for this type of revision is December 1, 2023, if the state intends for the SIP revision to be effective beginning with the 2025 control period. For states that submit this type of SIP revision, the deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024. Similarly, a state can submit a SIP revision beginning with the 2026 control period and beyond by December 1, 2024, with state allocations for the 2026 control period due June 1, 2025, and EPA recordation of the allocations by July 1, 2025.

The EPA received no comment on the option to replace certain allowance allocation provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can choose to replace the Federal EGU trading program with an integrated State EGU trading program through an approved SIP revision. Under this option, a state can submit a SIP revision that makes changes only to modify the EPA-determined default allocations and that adopts identical provisions for the remaining portions of the EGU trading program. This SIP option allows states to replace these FIP provisions with state-based SIP provisions while continuing participation in the larger regional trading program. As with the abbreviated SIP option discussed previously, to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chooses to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside. Also, for the same reasons discussed with respect to the abbreviated SIP option, the EPA is removing the option for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines.

Deadlines for this type of SIP revision are the same as the deadlines for abbreviated SIP revisions. For the SIP-based program to start with the 2025 control period, the SIP deadline is December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024, and so on.

The EPA received no comment on the option to replace the Federal trading program for EGUs with an integrated state trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

4. SIP Revisions That Do Not Use the Trading Program

States can submit SIP revisions to replace the FIP that achieve the necessary EGU emissions reductions but do not use the CSAPR NO_X Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO_X Ozone Season Group 3 Trading Program, the EPA would evaluate the transport SIP based on the particular control strategies selected and whether the strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (*i.e.,* reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved. To address the applicable CAA requirements, the SIP revision should include the following general elements: (1) a comprehensive baseline 2023 statewide NO_X emissions inventory (which includes existing control requirements), which should be consistent with the 2023 emissions inventory that the EPA used to calculate the required state budget in this final rule (unless the state can explain the discrepancy); (2) a list and description of control measures to satisfy the state emissions reduction obligation and a demonstration showing when each measure would be implemented to meet the 2023 and successive control periods; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe, monitoring and reporting under 40 CFR part 75, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP (*see* 40 CFR part 51, subpart K (''source surveillance'' requirements)); and (5) a projected inventory demonstrating that state measures along with Federal measures will achieve the necessary emissions reductions in time to meet the 2023 and successive compliance deadlines (*e.g.,* enforceable reductions commensurate with installation of SCR on coal-fired EGUs by the 2027 ozone season). The SIPs must meet procedural requirements under the Act, such as the requirements for public hearing, be adopted by the appropriate state board or authority, and establish by a practically enforceable regulation or permit(s) a schedule and date for each affected source or source category to achieve compliance. Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness before acting on the SIP. EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51, appendix V.

For further background information on considerations for replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU or Industrial Source Control Requirements

EPA's promulgation of a non-EGU transport FIP would in no way affect the ability of states to submit, for review and approval, a SIP that replaces the requirements of the FIP with state requirements. To replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The state SIP submittal must demonstrate that the emissions reductions required by the SIP would continue to ensure that significant contribution from that state has been eliminated through permanent and enforceable measures. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP.

The most straightforward method for a state to submit a presumptively approvable SIP revision to replace the non-EGU portion of the FIPs for the state would be to provide a SIP that includes emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources meeting the applicability criteria and associated compliance assurance provisions for each of the unit types identified in section VI.C of this document.

Comment: One commenter stated that they believed EPA's assertion in the proposal that any SIP submittal would have to achieve equal or greater reductions for non-EGUs than the FIP was unlawful. The commenter asserted that a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP).

Response: The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP; this is discussed in response to comments earlier in this section. For example, some states may desire to include non-EGUs in a trading program. This may be possible subject to taking into account a number of considerations as discussed earlier in this section to ensure equivalency between the different approaches. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP to be presumptively approvable. The EPA anticipates that such emissions reductions strategies would have to achieve reductions equivalent to or beyond those emissions reductions already projected to occur in EPA's emissions projections and air quality modeling conducted at Steps 1 and 2. Such reductions must also be achieved by the 2026 ozone season.

EPA further acknowledges that a demonstration of equivalency using other control strategies is complicated by the fact that the final emissions limits for non-EGU sources are generally unit-specific and expressed in a variety of forms; comparative analysis with alternative control requirements to determine equivalency would need to take this into account. Similarly, we recognize that the emissions trading program for EGUs in this action includes a number of enhancements to ensure that the Step 3 determination of which emissions are ''significant'' and must be eliminated continues to be implemented over time. Although there is not a fixed, mass-based emissions budget established for each state in this action, there are other objective metrics that could guide states in developing replacement SIPs. For example, for non-EGUs, states may choose to conduct an analysis of their industrial stationary sources and present an alternative set of emissions limits applying to specific units that it believes would achieve an equivalent level of emissions reduction. States could apply cost-effectiveness thresholds for emissions control technologies that could be applied to establish that some alternative emissions control strategy results in equivalent or greater improvement at downwind receptors. The EPA anticipates that such a comparison may entail review of both baseline emissions information and growth projections between the different sets of units to ensure that a truly equivalent or greater degree of emissions reduction is achieved; additionality and emissions shifting potential may also need to be considered. We note that the CAMx policy case run for 2026 provides a benchmark for assessing the level of air quality improvement anticipated at receptors with implementation of the FIP. This data may be of use to states as part of a demonstration that a replacement SIP achieves an equivalent or greater level of air quality improvement to the FIP; however, the use of such modeling in such a demonstration would need to be more fully evaluated at the time of such a SIP revision.

In all cases, a SIP submitted by a state to replace the non-EGU components of the FIPs would very likely need to rely on permanent and practically enforceable controls measures that are included in the SIP and, once approved by the EPA, rendered federally enforceable. So-called ''demonstration-only'' or ''non-regulatory'' SIPs would very likely be insufficient; see discussion in response to comments earlier in this section. Further, the EPA anticipates that states would bear the burden of establishing that the state's alternative approach achieves at least an equivalent level of emissions reduction as the FIP.

E. Title V Permitting

This final rule, like CSAPR, the CSAPR Update, and the Revised CSAPR Update does not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing Title V, 40 CFR parts 70 and 71.[406] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emissions limitations and other conditions as necessary to ensure compliance with the applicable requirements of the CAA, including the requirements of the applicable SIP. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this final rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements and already possess a title V operating permit. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the FIPs finalized in this action would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, EGU requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability, and for non-EGUs, the emissions limits and compliance requirements are, to the extent relevant to each source, ''applicable requirements'' that must be addressed in the permits.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the FIPs generally will have to be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 71.7(f)), significant modifications (40 CFR 70.7(e)(4)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[407] For sources newly subject to title V that are affected sources under the FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As was the case in the CSAPR, the CSAPR Update and the Revised CSAPR Update, the new and amended FIPs impose no independent permitting requirements and the title V permitting process will impose no additional burden on sources already required to be permitted under title V.

1. Title V Permitting Considerations for EGUs

Title V of the CAA establishes the basic requirements for state title V permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established in CSAPR, the CSAPR Update, the Revised CSAPR Update and this final rule. 42 U.S.C. 7661a(b); 40 CFR 70.6(a)(8) & (10); 40 CFR 71.6(a)(8) & (10).

In CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA established standard requirements governing how sources covered by those rules would comply with title V and its regulations.[408] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this rule, identical title V compliance provisions will apply with respect to the CSAPR NO_X Ozone Season Group 3 Trading Program. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.506(d)(1), 97.806(d)(1) and 97.1006(d)(1). This provision is also included in each title V permit for an affected source. This final rule maintains the approach taken under CSAPR, the CSAPR Update and the Revised CSAPR Update that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this final rule would also continue to support the means by which a source in the final trading program can use the title V minor modification procedure to change its approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update (*i.e.,* approaches using a continuous emissions monitoring system under subparts B and H of 40 CFR part 75, an excepted monitoring system under appendices D and E to 40 CFR part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of 40 CFR part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.506(d)(2), 97.806(d)(2) and 97.1006(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B). As described in EPA's 2015 Title V Guidance, sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update trading programs in which the source is required to participate, and the applicable requirements governing each of those approaches.[409] Inclusion of such a table in a source's title V permit therefore allows a covered unit that seeks to change or add to its chosen monitoring and recordkeeping approach to easily comply with the regulations

[406] Part 70 addresses requirements for state title V programs, and part 71 governs the Federal title V program.

[407] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

[408] The EPA has also issued a guidance document and template that includes instructions for how to incorporate the applicable requirements into a source's Title V permit. *See* Memorandum dated May 13, 2015, from Anna Marie Wood, Director, Air Quality Policy Division, and Reid P. Harvey, Director, Clean Air Market Division, EPA, to Regional Air Division Directors, Subject: ''Title V Permit Guidance and Template for the Cross-State Air Pollution Rule'' (''2015 Title V Guidance''), available at *https://www.epa.gov/sites/default/files/2016-10/documents/csapr_title_v_permit_guidance.pdf.*

[409] *Id.*

governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to the EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on EPA's website.[410] The EPA maintains the same approach for the trading program in this final rule.

2. Title V Permitting Considerations for Industrial Stationary Sources

For non-EGU sources, affected sources will need to work with their local, state, or tribal permitting authority to determine if the new applicable requirements should be incorporated into their existing title V permit under the reopening for cause, significant modification, or permit renewal procedures of the approved permitting program. Title V permits for existing sources will need to be updated to include the applicable requirements of this final rule and any necessary preconstruction permits obtained in order to comply with this final rule.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

Sources in states affected by both the NO_X SIP Call for the 1979 ozone NAAQS and the requirements established in this final rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. With respect to EGUs larger than 25 MW, in this rule the EPA is requiring NO_X ozone season emissions reductions from these sources in many of the NO_X SIP Call states, and at greater stringency than required by the NO_X SIP Call, by requiring the EGUs to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program. The emissions reductions required under this rule are therefore sufficient to satisfy the emissions reduction requirements under the NO_X SIP Call for these large EGUs.

With respect to the large non-EGU boilers and combustion turbines that formerly participated in the NO_X Budget Trading Program under the NO_X SIP Call, the EPA provided options under both the CSAPR Update and the Revised CSAPR Update for states to address these sources' ongoing NO_X SIP Call requirements by expanding applicability of the relevant CSAPR trading programs for ozone season NO_X emissions to include the sources, and no state chose to use these options. As discussed in sections VI.D.2 and VI.D.3, in this rule the EPA is removing the previous regulatory text defining specific options for states to expand trading program applicability to include these sources and instead will evaluate any SIP revisions seeking to include these sources in the Group 3 trading program on a case-by-case basis.[411]

2. Acid Rain Program

This rule does not affect any SO_2 and NO_X requirements under the Acid Rain Program, which are established separately under 40 CFR parts 72 through 78 and will continue to apply independently of this rule's provisions. Sources subject to the Acid Rain Program will continue to be required to comply with all requirements of that program, including the requirement to hold sufficient allowances issued under the Acid Rain Program to cover their SO_2 emissions after the end of each control period.

3. Other CSAPR Trading Programs

This rule does not substantively affect any provisions of the CSAPR NO_X Annual, CSAPR SO_2 Group 1, CSAPR SO_2 Group 2, CSAPR NO_X Ozone Season Group 1, or CSAPR NO_X Ozone Season Group 2 trading programs for sources that continue to participate in those programs. Sources subject to any of the CSAPR trading programs will continue to be required to comply with all requirements of all such trading programs to which they are subject, including the requirement to hold sufficient allowances issued under the respective programs to cover emissions after the end of each control period.

The EPA also notes that where a state's good neighbor obligations with respect to the 1997 ozone NAAQS or the 2008 ozone NAAQS have previously been met by participation of the state's large EGUs in the CSAPR NO_X Ozone Season Group 2 Trading Program (or earlier by the CSAPR NO_X Ozone Season Group 1 Trading Program), the EPA will deem those obligations to be satisfied by the participation of the same sources in the CSAPR NO_X Ozone Season Group 3 Trading Program. Specifically, for all states covered by the Group 3 trading program under this rule except Minnesota, Nevada, and Utah, participation of the state's EGUs in the Group 3 trading program will be deemed to satisfy not only the EGU-related portion of the state's good neighbor obligations with respect to the 2015 ozone NAAQS but also the state's good neighbor obligations with respect to the 2008 ozone NAAQS. In addition, for Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Wisconsin, participation of the state's EGUs in the Group 3 trading program will also be deemed to satisfy the state's good neighbor obligations with respect to the 1997 ozone NAAQS.[412]

VII. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with EPA's commitment to integrating environmental justice in the agency's actions, and following the directives set forth in multiple Executive orders, the Agency has analyzed the impacts of this final rule on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. Executive Order 12898 is discussed in section X.J of this final rule and analytical results are available in Chapter 7 of the *RIA*. This analysis is being provided for informational purposes only.

A. Introduction

Executive Order 12898 directs EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples.[413] Additionally, Executive

[410] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[411] Only one NO_X SIP Call state—Tennessee—continues to participate in the Group 2 trading program, and the EPA has already approved other SIP provisions addressing the ongoing NO_X SIP Call obligations for Tennessee's large non-EGU boilers and combustion turbines. *See* 84 FR 7998 (March 6, 2019); 86 FR 12092 (March 2, 2021).

[412] For the remaining state transitioning from the Group 2 trading program to the Group 3 trading program under this rule—Texas—as well as the remaining states that transitioned from the Group 2 trading program to the Group 3 trading program under the Revised CSAPR Update—Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—participation of the states' EGUs in the Group 2 trading program as required by the CSAPR Update was addressing good neighbor obligations of the states with respect to only the 2008 ozone NAAQS, not the 1997 ozone NAAQS. *See* 81 FR 74523–74526.

[413] 59 FR 7629, February 16, 1994.

ATTACHMENT RA-6

NV Energy Response to Staff Data Request 01

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	09-06-2023
REQUEST NO:	Staff 01	**KEYWORD:**	GEN-4; LSAP p14 fig 4 Tracy 4/5 continuing operations capital; engineering econo
REQUESTER:	Cameron	**RESPONDER:**	Amos, Scott (NV Energy)

REQUEST:

Reference: Technical Appendix Gen-4

Question: Reference Gen-4, the LSAP for Tracy 4/5, at page 14 of 18, figure 4 – Tracy 4/5 Continuing Operations Capital.

Please provide Staff with an analysis justifying each line item in the table from both an engineering and economic perspective.

RESPONSE CONFIDENTIAL (yes or no): No.

ATTACHMENT CONFIDENTIAL (yes or no): No.

TOTAL NUMBER OF ATTACHMENTS: One.

RESPONSE:

The economic analysis for each of the individual projects has not yet been completed. An AFE/business case will be completed for each project in the future, prior to starting the project. A high-level justification for each item is provided in the attached .pdf document

Tracy 4/5 Retirement Date - Capital Replacements

#	Description	Cost	Year	Notes
1	SCR Installation	$12,000,000	2027	EPA regional haze rule requires the best available emissions technology be installed on this unit if the retirement date is extended. NV Energy has determined an SCR is the lowest cost option that meets this requirement. A business case will be developed closer to the expected project execution year.
2	CT New Rotor	$10,000,000	2027	The OEM of the combustion turbine recommends replacement of the rotor at an interval that will be exceeded if the retirement date is extended. If not replaced the unit would be at risk of a catastrophic failure that would take months possibly years to restore the unit to service. NV Energy completes periodic inspection and testing of this component to monitor the condition. A business case will be developed closer to the expected project execution year.
3	CT Generator Rewind	$4,000,000	2027	The OEM of the combustion turbine generator recommends replacement of the generator windings at an interval that will be exceeded if the retirement date is extended. If not replaced the unit would be at risk of a catastrophic failure that would take months to restore the unit to service. NV Energy completes periodic inspection and testing of this component to monitor the condition. A business case will be developed closer to the expected project execution year.
4	ST Generator Rewind	$4,000,000	2027	The OEM of the steam turbine generator recommends replacement of the generator windings at an interval that will be exceeded if the retirement date is extended. If not replaced the unit would be at risk of a catastrophic failure that would take months to restore the unit to service. NV Energy completes periodic inspection and testing of this component to monitor the condition. A business case will be developed closer to the expected project execution year.
5	Replacement Demin Train	$4,000,000	2027	The demineralized water supply system is nearing it's end of life and replacement of the entire system or key components will be necessary to ensure continued reliability of Tracy Station past the current retirement date. A business case will be developed closer to the expected project execution year.
6	Plant Automation	$5,000,000	2027	As critical valves near their end of life it would be wise to replace them with the latest technology to ensure unit availability and reliability. A business case will be developed closer to the expected project execution year.
7	DCS Upgrade	$4,000,000	2031	Historically the DCS system requires replacement roughly every 10 years. The retirement date extension would require an additional unplanned replacement. A business case will be developed closer to the expected project execution year.

8	Load Gear Replacement	$2,500,000	2027	The OEM of the load gear recommends replacement at an interval that will be exceeded if the retirement date is extended. If not replaced the unit would be at risk of a catastrophic failure that would take months to years to return the unit to service. NV Energy completes periodic inspection and testing of this component to monitor the condition. A business case will be developed closer to the expected project execution year.
9	ST Valve Replacement	$3,000,000	2027	The OEM of the steam turbine valves recommends replacement at an interval that will be exceeded if the retirement date is extended. If not replaced the unit would be at risk of a catastrophic failure that would take months to return the unit to service. NV Energy completes periodic inspection and testing of this component to monitor the condition. A business case will be developed closer to the expected project execution year.
10	Clarifier Replacement	$5,000,000	2031	The waste water clarifier system is nearing it's end of life and replacement of the entire system or key components will be necessary to ensure continued reliability of Tracy Station past the current retirement date. A business case will be developed closer to the expected project execution year.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the **DIRECT TESTIMONY OF ROSE ANDERSON ON BEHALF OF SIERRA CLUB** in Docket No. 23-08015 by electronic mail to the following:

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