Technical Support Document (TSD)
for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

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Ozone Transport Policy Analysis
Proposed Rule TSD

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The analysis presented in this document supports the EPA's proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (Cross-State Air Pollution Rule for the 2015 Ozone NAAQS). This TSD includes analysis to help quantify upwind state emissions that significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in downwind states and quantification of emission budgets (i.e., limits on emissions) and the resulting effects on air quality primarily focused on EGUs. The analysis is described in Sections VI and VII of the preamble to the rule. This TSD also broadly describes how the EPA used historical data and the Integrated Planning Model (IPM) to inform air quality modeling, budget setting, and policy analysis aspects of this rule for EGUs, as well as describing some limited analysis for overcontrol of the non-EGU policy scenarios. Finally, this TSD includes an assessment on the effects of ozone concentrations on forest health. This TSD is organized as follows:

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A. Using Engineering Analytics and Integrated Planning Model (IPM) in Step 3 Assessment of Significant Contribution to Nonattainment and Interference with Maintenance

In order to establish EGU NO_X emissions control stringencies for each linked upwind state, EPA first identifies various possible uniform levels of NO_X control stringency based on available EGU NO_X control strategies and represented by cost thresholds.[1] The EGU emission reductions pertaining to each level of control stringency are derived using historical data, engineering analyses, and the Integrated Planning Model (IPM) for the power sector as described in sections B and C of this TSD. A similar assessment for one scenario was done for non-EGUs. Next, EPA uses the ozone Air Quality Assessment Tool (AQAT) to estimate the air quality impacts of the upwind state emissions reductions on downwind ozone pollution levels for each of the assessed cost threshold levels. Specifically, EPA looks at the magnitude of air quality improvement at each receptor at each level of control, it also examines whether receptors change status (shifting from either nonattainment to maintenance, or from maintenance to attainment), and looks at the individual contributions of each state to each of its receptors. See section D in this TSD for discussion of the development and use of the ozone AQAT.

In this TSD, EPA assesses the EGU NO_X mitigation potential for all states in the contiguous U.S. EPA assessed the air quality impacts from emission reductions for all monitors in the contiguous U.S. for which air quality contribution estimates were available. In applying the multi-factor test for purposes of identifying the appropriate level of control, the EPA evaluated NO_X reductions and air quality improvements at the 29 receptors from the 9 home states, excluding California and its receptors, and the 26 upwind[2] that were linked to downwind receptors in step two of the 4-Step Good Neighbor Framework. These states are listed in Table A-1 below. Since California EGUs are not covered in this proposed rule, this TSD's references to "affected states" or "states covered by this rule" *in EGU-related material* does not include California.[3]

Table A-1. Upwind States Evaluated in the Multi-factor Test

Alabama+	Nevada
Arkansas	New Jersey
California*	New York
Delaware+	Ohio

[1] See the EGU NO_X Mitigation Strategies Proposed Rule TSD.

[2] Note that 7 of the 26 upwind states are also states with non-attainment or maintenance receptors, or "home states." Colorado and Connecticut are home states, but do not significantly contribute to a downwind state non-attainment or maintenance receptor.

[3] EPA notes that there are two receptors on tribal lands in California. The regulatory ozone monitor located on the Morongo Band of Mission Indians ("Morongo") reservation is a projected downwind receptor in 2023 and the Temecula, California regulatory ozone monitor is a projected downwind receptor in 2023 (and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians ("Pechanga") reservation). As California EGUs are not covered in this action (and no other state would be linked to these receptors), EPA does not include these receptors when discussing receptors impacted by EGU reductions. However, these receptors and their corresponding design value change due to both EGU reductions (in non-California states) and non-EGU reductions elsewhere and in California and are shown in the accompanying AQAT file. See Ozone_AQAT_Proposal.xlsx for results.

Illinois	Oklahoma
Indiana	Pennsylvania
Kentucky	Tennessee+
Louisiana	Texas
Maryland	Utah^
Michigan	Virginia
Minnesota	West Virginia
Mississippi	Wisconsin
Missouri	Wyoming

**California EGUs are not covered by this rule.*
+Linkages for Alabama, Delaware, and Tennessee are resolved before 2026. Therefore, those states have a lower level of emission control stringency compared to states that continue to be linked in 2026.
^ In recognition of Utah's lack of state jurisdiction over an existing EGU in the Uintah and Ouray Reservation, that reservation was evaluated separately from the rest of the land within Utah's borders.

Similar to the CSAPR Update and the Revised CSAPR Update, EPA relied on adjusted historical data (engineering analytics) and its power sector modeling platform using IPM as part of the process to identify emissions control stringencies to eliminate significant contribution at step three within the 4-Step Good Neighbor Framework. Historical data were adjusted through the engineering analytics tool and used along with IPM to analyze the ozone season NO_X emission reductions available from EGUs at various uniform levels of NO_X control stringency, represented by cost per ton, in each upwind state. Finally, IPM was used to evaluate compliance with the rule and the rule's regulatory control alternatives (i.e., compliance with the emission budgets, with a more stringent alternative, and with a less stringent alternative). EPA also used its engineering analytics tool and IPM projections to perform air quality assessment and sensitivity analysis as part of step 3.

The engineering analytics tool uses the latest historical representative emissions and operating data reported under 40 CFR part 75 by covered units (which were 2021 ozone-season data at the time of this analysis). It is a tool that builds estimates of future unit-level and state-level emissions based on exogenous changes to historical heat input and emissions data reflecting fleet changes that will occur subsequent to the last year of available data. See Section C. *Calculating Budgets from Historical Data and IPM Analysis* for a detailed description of the engineering analytics tool.

IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector that EPA uses to analyze cost and emissions impacts of environmental policies.[4] All IPM cases for this rule included representation of the Title IV SO_2 cap and trade program; the NO_X SIP Call; the CSAPR and CSAPR Update regional cap and trade programs; consent decrees and settlements; and state and federal rules as listed in the IPM documentation referenced above.

To quantify the emission reduction potential of generation shifting correlated to each control stringency representing different pollution control technologies, EPA conducted a set of modeling runs referred to as the "Cost Threshold Cases." EPA first adjusted the model to reflect

[4] See "Documentation for EPA's Power Sector Modeling Platform v6 using Summer 2021 Reference Case". Available at https://www. https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case

the relevant control technologies being considered (referred to as the "Adjusted Base Case" for each stringency level) and then imposed a dollar per ton price constraint (e.g., $1,800/ton, or $10,000/ton) to project the additional reductions expected from generation shifting commensurate with the estimated representative technology cost at that control stringency level.

For the "Cost Threshold" IPM runs, the EPA designed a series of IPM runs that imposed increasing cost thresholds representing uniform levels of NO_X controls and tabulated those projected emissions for each state at each cost level. These tabulations, when combined with adjusted historical data, are described as "cost curves."[5] The cost curves report the remaining emissions at each cost threshold for each state after EGUs have made emission reductions that are available up to the particular cost threshold analyzed, inclusive of the pollution reduction technologies available in that control stringency as well as emission reductions from generation shifting at a commensurate representative cost per ton.

In each Cost Threshold run, the EPA applied the applicable ozone-season cost level to all fossil-fuel-fired EGUs with a capacity greater than 25 MW in all states, though only the estimates for the nonattainment and maintenance receptors, the "home states" for those receptors, and the affected states with proposed EGU reductions affect the results in step 3. As described in the EGU NO_X Mitigation Strategies Proposed Rule TSD, because of the time required to build advanced pollution controls, the model was prevented from building any new post-combustion controls, such as SCR or SNCR, before the 2025 run year,[6] in response to the cost thresholds.[7] Similarly, the model was not enabled to build incremental new units in that time frame. In response to the ozone-season NO_X cost, the modeling assumes turning on idled existing SCR and SNCR, optimization of existing SCR, adding or upgrading NO_X combustion controls (such as state-of-the-art low NO_X burners (LNB)) in 2023/2024, and projects shifting generation to lower-NO_X emitting EGUs. In this TSD, we sometimes refer to state-of-the-art combustion controls, or SOA CC, generally, as combustion controls. For details on which measures are endogenously modeled within IPM and which are not, please see Appendix Table C-1.

In these scenarios, EPA imposed cost thresholds of $1,800 and $11,000/ton of ozone season NO_X.[8] See Preamble Section VI for a discussion of how the cost thresholds were

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[5] These projected state level emissions and heat input for each "cost threshold" run are presented in several formats. The IPM analysis outputs available in the docket contain a "state emissions" file for each analysis. The file contains two worksheets. The first is titled "all units" and shows aggregate emissions for all units in the state. The second is titled "all fossil > 25MW" and shows emissions for a subset of these units that have a capacity greater than 25 MW. The 2023 and 2025 emissions and heat input in the "all fossil > 25 MW" worksheet is used to derive the generation shifting component of the state emission budgets for each upwind state at level of emission control stringency.

[6] IPM uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. For this analysis, IPM maps the calendar year 2023 to run year 2023, calendar years 2024-2026 to run year 2025 and calendar years 2027-2029 to run year 2028. For model details, please see Chapter 2 of the IPM documentation, available at:
https://www.epa.gov/system/files/documents/2021-09/epa-platform-v6-summer-2021-reference-case-09-11-21-v6.pdf

[7] IPM results do include certain newly built post-combustion NO_X control retrofits in base case modeling, cost curve runs, and remedy runs. These pre-2023 retrofits do not reflect any controls installed in response to the rule, but instead represent those that are already announced and/or under construction and expected to be online by 2023, or controls that were projected to be built in the base case in response to existing consent decree or state rule requirements.

[8] The $11,000/ton cost threshold run is named such to clarify it is linked to that level NO_X Mitigation stringency measures. Because the run was conducted before the $11,000/ton representative price was calculated, the run only imposes a NO_X price of $10,000/ton. Since that NO_X price did not induce significant amounts of generation shifting,

determined. Table A-2 below summarizes the reduction measures that are broadly available at various cost thresholds.

Table A-2. Reduction strategies available to EGUs at each cost threshold.

Cost Threshold ($ per ton Ozone-Season NO_X)	Reduction Options
$1,800	-Generation Shifting; -Retrofitting state-of-the-art combustion controls; -Optimizing idled SCRs; -Optimizing operating SNCRs[9]
$11,000	-All options above and; -Installing SCR and SNCR on coal and oil/gas steam units greater than 100 MW and lacking post combustion controls.

For both Engineering analytics and IPM:

- At $1,800/ton:
    - Engineering Analytics
        - If 2021 adjusted baseline rate was greater than 0.08 lb/MMBtu for SCR controlled coal units, that rate and corresponding emissions were adjusted down to 0.08 lb/MMBtu starting in 2023;
        - for SCR controlled oil/gas units, if the adjusted historical rate was greater than 0.03 lb/MMBtu then the rate was adjusted downwards to 0.03 lb/MMBtu starting in 2023;
        - for SCR controlled combined cycle units, if the adjusted historical rate was greated than 0.012 lb/MMBtu then the rate was adjusted downwards to 0.012 lb/MMBtu in 2023;
        - for SCR controlled combustion turbine units, if the adjusted historical rate was greated than 0.03 lb/MMBtu then the rate was adjusted downwards to 0.03 lb/MMBtu in 2023; and
        - for units with LNB upgrade potential and an adjusted historical rate greater than 0.199 lb/MMBtu, their rates were adjusted downwards to 0.199 lb/MMBtu starting in 2023.
        - Starting in 2023 units with SNCRs were given their mode 2 NO_X rates[10] if they were not already operating at that level or better in 2019.

    - IPM - cost of $1,800/ton applied to EGUs > 25 MW; units with existing SCRs have their emission rates lowered to the lower of their mode 4 NO_X rate in

given the other mitigation strategies included in the model run, EPA does not believe that the results would have changed appreciably if a $11,000/ton price on NO_X was included instead.

[9] As explained in the preamble section VI.B, EPA notes that this technology becomes widely available at $1,800/ton. For purposes of assessing generation shifting available at this technology level's commensurate cost, EPA relies on its $1,800/ton IPM analysis.

[10] For a unit with an existing post-combustion control, mode 1 reflects the existing post-combustion control not operating and mode 2 the existing post-combustion control operating. For details, please see Chapter 3.10 of the IPM documentation available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.

NEEDS and the "widely achievable" optimized emissions rate consistent with the rates used in the Engineering Analysis. [11]

- At $11,000/ton:
  - Engineering Analytics – Same as $1,800/ton; additionally, coal units greater than 100 MW and lacking a SCR were given an emission rate equal to 0.05 lb/MMBtu reflecting SCR installation starting in 2026. Oil/gas steam units greater than 100 MW and operating at an average 20% capacity factor or higher were given an emission rate of 0.03 lb/MMBtu reflecting SCR installation starting in 2026.

  - IPM – Cost of $10,000/ton applied to EGUs > 25 MW;[12] in addition to the emission rate adjustments noted in the $1,800/ton scenario, coal units greater than 100 MW and lacking SCR were assigned an emission rate of 0.05 lb/MMBtu reflecting SCR installation starting in model run year 2025. Oil/gas steam units greater than 100 MW were given an emission rate of 0.03 lb/MMBtu reflecting SCR installation in model year 2025 (to which calendar year 2026 is mapped).

As described in preamble section VI.B, the EPA limited its assessment of generation shifting to reflect shifting only to other EGUs within the same state as a proxy for generation shifting that could occur during the near-term implementation timeframe of the rule. EPA did this by establishing a minimum level of required generation in each state in each Cost Threshold run equal to its respective Base Case generation level. EPA also prohibited the model from constructing any new (unplanned) capacity built in response to the price signal in the near term as it was interested in capturing generation shifting among the existing fleet.

B. Calculating Step 4 EGU Emission Budgets from Historical Data and IPM Analysis

In this proposed rule the EPA calculated state budgets with the following formula:

$$\textbf{2023 State OS NO}_\textbf{X}\textbf{ Budget} = \text{2023 State OS Baseline Heat Input} * [\text{2023 } \mathit{State\ OS\ NO_X\ Emissions\ Rate} - (\text{2023 } \mathit{IPM\ Base\ Case\ OS\ NO_X\ Emissions\ Rate} - \text{2023 IPM Cost Threshold } \mathit{OS\ NO_X}\text{ EmissionsRate})]$$ [13]

The first two variables in the equation are derived from historical data and are the primary determinants of states' emissions budgets. They are described in sections B.1 and B.2 below.

[11] The mode 4 NO_X rate, as described in Chapter 3 of the Documentation for EPA Base Case v.6 Using Integrated Planning Model, represents post-combustion controls operating and state-of-the-art combustion controls, where applicable. For units determined to be operating their SCR, the rate is typically equal to the unit's rate reported in previous year ETS data. For units not operating their SCRs, the mode 4 rate is calculated as described in Attachment 3-1 of Documentation for EPA's Power Sector Modeling Platform v6 using Summer 2021 Reference Case available at https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.

[12] See footnote 8 for explanation of why $10,000/ton was used in the IPM modeling.

[13] The year in the formula changes for each year of budget calculation.

The last two variables are identified through IPM analysis and described in section B.3 below.[14] In section B.4, EPA discusses variability limits.

1. Calculating 2023-2026 Engineering Baseline Heat Input

The underlying data and calculations described below can be found in the workbook titled (Appendix A – Proposed Rule State Emission Budget Calculations and Engineering Analytics). They are *also available in the docket and on the EPA website.*

EPA starts with 2021 reported, seasonal, historical NO_X emissions and heat input data for each unit.[15] This reflects the latest representative owner/operator reported data available at the time of EPA analysis. The NO_X emissions data for units that report data to EPA under the Acid Rain Program (ARP), Cross-State Air Pollution Rule (CSAPR), CSAPR Update, and Revised CSAPR Update are aggregated to the summer/ozone season period (May-September). Because the unit-level NO_X emissions for the summer/ozone-season period are relevant to determining ozone-season emissions budgets, those files are shown in the "unit 2023" through "unit 2026" sheets in the "Appendix A: Proposed Rule State Emission Budget Calculations and Engineering Analytics" file accompanying this document.[16] In that file, unit-level details such as facility name, unit ID, unit type, capacity, etc. are shown in columns A through H of the "unit 2023" through "unit 2026" worksheets. Reported historical data for these units such as unit type, fuel, existing post combustion controls, historical emissions, heat input, generation, etc. are shown in columns I through W. For approximately twenty additional units that have not reported to EPA but which are included in this proposal, EIA data sources are used to obtain the necessary data. The 2021 historical emissions value is in column Q. The assumed future year baseline emissions estimate (e.g., 2023-2026) is shown in column AF, and reflects either the same emissions level as that observed in 2021, or a modification of that value based on changes expected to the operational or pollution control status of that unit.[17] These modifications are made due to:

   a. *Retirements* - Emissions from units with upcoming confirmed retirement dates are adjusted to zero for years subsequent to that retirement date. Retirement dates are identified through a combination of sources including EIA Form 860, utility-announced retirements, stakeholder feedback provided to EPA, and the National Electricity Energy Data System (NEEDS) October 2021 file. The impact of retirements on emissions is shown in column X. The retiring units are flagged in column Y.[18]

[14] Given the proximity of the first implementation year to the analytics for this rulemaking and its promulgation, EPA determined the use of this approach to develop budgets to implement the chosen level of emission control stringency provided the most precision and expediency for this rulemaking.

[15] "Seasonal" refers to the ozone-season program months of May through September.

[16] The EPA notes that historical unit-level ozone season EGU NO_X emission rates are publicly available and quality assured data. The emissions are monitored using continuous emissions monitors (CEMs) or other monitoring approaches available to qualifying units under 40 CFR part 75 and are reported to the EPA directly by power sector sources.

[17] Based on data and changes known at time of analysis.

[18] EPA updated its inventory of units flagged as retiring in column N based on stakeholder input, including on previous rulemakings and the latest data from EIA 860 and the PJM retirement tracker.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	*0 MMBtu* x 0.2 lb/MMBtu = *0 ton*

b. *Coal to Gas Conversion* – Emissions from coal units with scheduled conversions to natural gas fuel use are adjusted to reflect reduced emission rates associated with natural gas for years subsequent to that conversion date. To reflect a given unit's conversion to gas, that unit's future emission rates for NO_X are assumed to be half of its 2021 coal-fired emission rates while utilization levels are assumed to remain the same.[19] Therefore, the future year estimated emissions for these converting units are expected to be half of 2021 levels for NO_X. Units expected to convert to gas are flagged using EIA Form 860, NEEDS October 2021, and stakeholder feedback. The impact of coal to gas conversion for the future year is shown in column AB, flagged in column AC. The example below pertains to NO_X emission estimates.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0.*1 lb/MMBtu* = 0.5 *ton*

c. *Retrofits* – Emissions from units with scheduled SCR or SNCR retrofits are adjusted to reflect the emission rates expected with new SCR installation (0.05 lb/MMBtu of NO_X) and new SNCR (25% decrease in previously reported emission rate for all boilers except circulating fluidized bed boilers that receive a 50% decrease in previously reported emission rate) and are assumed to operate at the same 2021 utilization levels.[20] These emission rates were multiplied by the affected unit's 2021 heat input to estimate the future year emission level. The impact of post-combustion control retrofits on future year emissions assumptions is shown in column AD, flagged in column AE.

For SNCR:

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0.*15 lb/MMBtu* = 0.75 *ton*

For SCR:

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0.*050 lb/MMBtu* = 0.25 *ton*

d. *Other* – EPA also made several unit-specific adjustments to 2021 emission levels to reflect forthcoming emission or emission rate requirements specified in consent decrees, BART requirements, and/or other revised permit limits. The impacts for future year emission assumptions are shown in column AF, flagged in column AG.[21]

[19] This is consistent with NO_X rate change used in IPM. See "Documentation for EPA's Power Sector Modeling Platform v6 using Summer 2021 Reference Case." table 5-18.
[20] *Ibid.*
[21] EPA checked its inventory of units impacted by consent decrees based on input provided stakeholders and comments on previous rulemakings. No units were determined to be impacted as described in the Allowance Allocation under the Proposed Rule TSD.

e. *New Units* – Emissions for new units are identified in the “New units” worksheet. They reflect under-construction and/or permitted units greater than 25 MW that are expected to be in commercial operation by the designated future year. These assumed emission values for new units are reflected in column F and the online years are in column H. To obtain these emissions, EPA identified all new fossil-fired EGUs coming online after 2021 according to EIA Form 860 and in NEEDSv.6 October 2021. EPA then identified the heat rate and capacity values for these units using EIA Form 860, NEEDSv.6 October 2021 and stakeholder-provided data. Next, EPA identified the 2019 average seasonal capacity factor for similar units that came online between 2015-2019. EPA used these seasonal capacity factors (e.g., 65% for natural gas combined cycle units and 10% for combustion turbines), the unit’s capacity, the unit’s heat rate, and the unit’s estimated NO_X rate to estimate future year emissions (capacity × capacity factor × number of hours in ozone season × heat rate × NO_X emission rate = NO_X emissions).[22]

	2021	Future Year (e.g., 2023)
Unit x	0 MMBtu x0.0 lb/MMBtu = 0 ton	100 MW *0.65 *(153x24) *8000 Btu/KWh *0.01 lb/MMBtu = 9 tons

After completing these steps, EPA has unit-level and state-level future year baselines that originate from the most recently reported representative data (2021) and incorporate known EGU fleet changes. The state-level file reflects a summation of the unit-level values and provides the state-level heat input value used as the first variable in the emissions budget formula below.[23]

2023 State OS NO_X Budget =
2023 State OS Baseline Heat Input $*[2023\ State\ OS\ NO_X\ Emissions\ Rate -$
$(2023\ IPM\ Base\ Case\ OS\ NO_X\ Emissions\ Rate\ -$ 2023 IPM Cost Threshold $OS\ NO_X$ Emissions Rate)]

2. <u>Estimating impacts of combustion and post combustion controls on state-level emission rates</u>

Next, EPA evaluates the impact of the different combustion and post-combustion controls to determine the second variable in the equation above. Similar to the methodology above, EPA continued to adjust the historical data to reflect a future year with specific uniform control assumptions. However, these adjustments were to capture changes incremental to the baseline reflecting different uniform control measures. EPA applied these adjustments for analytical purposes to all states, but only the affected states’adjustments are relevant for emission budgets

[22] Emission rate data is informed by the NEEDS data and historical data for like units coming online in the last five years. See “2019 and 2020 new NGCC Data” worksheet in the “EGU Power Sector 2019 and 2020 data” file in the docket.

[23] EPA also created a future year baseline for 1) NO_X and SO_2 emission from EGUs not currently covered under existing EPA programs that require emissions monitoring and reporting under 40 CFR part 75, and for other pollutants for all grid connected EGUs (e.g., $PM_{2.5}$, $P.M_{10}$, CO). These data points were used in some of the air quality analysis and in some of the system impacts estimates for the RIA. In the appendix to this TSD, the EPA evaluates whether the assumed aggregate heat input changes given retirements and new builds are consistent with trends observed historically in the fleet and with new planned units identified in EIA Form 860.

proposed in this rule. Each of these adjustments is shown incrementally for the relevant mitigation technology in the "unit 2023" through "unit 2026" worksheets.

a. *SCR optimization* – Emissions from units with existing SCRs, but that operated at an emission rate greater than a fuel and unit type optimized level (0.08 lb/MMBtu for coal steam, 0.03 for oil/gas steam, 0.03 for combustion turbine, and 0.012 for combined cycle) in 2021, were adjusted downwards to reflect expected emissions when the SCR is operated to the applicable optimized emission rate. The applicable optimized emission rate is multiplied by baseline heat input level to arrive at the future year emissions estimate for a given unit. The impact on future year emission assumptions is shown in column AH and flagged in column AI of the "unit 2023" through "unit 2026" worksheets. EPA notes this assumption only applies to ozone-season NO_X as that is the season in which this rule would likely incentivize such operation. In the proposed rule, EPA also incorporated a flag in column AI for units with SCRs and a shared stack. For these units, EPA did not assume potential emission reductions attributable to existing SCR optimization as explained in preamble section VI.B.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0.*08 lb/MMBtu* =0.4 *ton*

b. *State-of-the-art combustion controls* – Emissions from units that were operating in 2021 without state-of-the-art combustion controls were adjusted downwards to reflect assumed installation of, or upgrade to, these controls and their expected emission rate impact. EPA assumed a future year emission rate of 0.199 lb/MMBtu for units expected to install/upgrade combustion controls. This emission rate was multiplied by each eligible unit's future year baseline heat input to estimate its future emission level. Details of EPA's assessment of state-of-the-art NO_X combustion controls and corresponding emission rates are provided in the EGU NO_X Mitigation Strategies Proposed Rule TSD. The impact of state-of-the-art combustion controls on future year emission assumptions is shown in column AJ and flagged in column AK of the "unit 2023" through "unit 2026" worksheets. EPA also incorporated a flag in column AK, based on stakeholder input, for units with a shared stack. For these units, based on stakeholder provided data, EPA did not assume potential emission reductions attributable to state-of-the-art combustion controls as explained in preamble section VI.B. Note, these assumptions apply emissions adjustments throughout the entire year as the controls operate continuously once installed.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.4 lb/MMBtu = 2 ton	10,000 MMBt*u* x0 0.*199lb/MMBtu* = ~1 *ton*

c. *SNCR optimization* - Emissions from units with existing SNCRs, but that operated at an emission rate greater than the SNCR optimization rate, were adjusted downwards to reflect expected emissions when the SNCR is optimized. This emission rate was identified specific to each unit based on historical data and is described in the EGU NO_X Mitigation Strategy Proposed Rule TSD. The optimized emission rate is multiplied by future year baseline heat input levels to arrive at the future year emissions estimate. For the units affected by this adjustment, the impact on future year emission assumptions is shown in column AL and flagged in column AM of the “unit 2023” through “unit 2026” worksheets. Note, this assumption only applies to ozone-season NO_X as that is the season in which this proposal’s programwould likely incentivize such operation.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0.*15 lb/MMBtu* = 0.75 *ton*

Post Combustion Control Retrofits (SNCR and SCR): Emissions for eligible coal and oil/gas steam units were adjusted to reflect expected emission reductions from the retrofit of of either an SCR or SNCR. Table B.1 shows the eligibility of units assumed to receive each type of retrofit in the engineering analysis. Uncontrolled units at coal facilities that share a stack with an existing SCR but are also eligible to receive a new retrofit SCR are given an emission rate assuming an optimized new SCR in years for which this control measure is available. For more information an the retrofit assumptions, see section VI.B of the Preamble.

Table B.1. Post-Combustion Control Retrofit Assumptions for Coal and Oil/Gas Steam Units in the Engineering Analysis.

Fuel	Unit Type	Capacity (MW)	Average of 2019 to 2021 Ozone Season NO_X (tons)	Retrofit Type	Emission Rate (lb/MMBtu)
Coal	not CFB	>=100	All	SCR	0.05
Coal	not CFB	<100	All	SNCR	25% reduction
Coal	CFB	All	All	SNCR	50% reduction
Oil/Gas	All	>=100	>=150	SCR	0.03

i. SNCR retrofit– Emissions from coal steam units less than 100 MW without post-combustion controls as well as coal-fired circulating fluidized bed (CFB) boilers of any size without post-combustion controls were adjusted downwards to reflect expected emissions if an SNCR were to be retrofitted on the unit. The emission rate was identified as the higher of 75% of the unit’s baseline emission rate level (i.e., reflecting a 25% reduction from the technology) or 0.08 lb/MMBtu (i.e., an emission rate floor for SNCR).[24] For CFB units, the emission rate was identified as the higher of 50% of the unit’s baseline emission rate level or 0.08 lb/MMBtu. The adjusted emission rate is multiplied by future year baseline heat input levels to arrive at the future year emissions estimate for that technology. For the units affected by this adjustment, the impact on future year emission assumptions is shown in column AP and flagged in column AQ of the “unit 2023” through “unit 2026” worksheets.

[24] See https://www.epa.gov/airmarkets/retrofit-cost-analyzer for the “Retrofit Cost Analyzer (Update 1-26-2022)” Excel tool and for the documentation of the underlying equations in "IPM Model – Updates to Cost and Performance for APC Technologies: SNCR Cost Development Methodology for Coal-fired Boilers" (August 2021).

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0*.15 lb/MMBtu* = 0.75 *ton*

ii. SCR retrofit- Emissions from 1) coal units greater than 100 MW without SCR controls and 2) oil/gas steam units greater than 100 MW without an SCR and a three year (2019-2021) average of ozone season emissions of at least 150 tons were adjusted downwards to reflect expected emissions if an SCR were to be retrofitted on the unit. The emission rate was identified as the higher of 10% of the unit's baseline emission rate or 0.05 lb/MMBtu for coal steam units and 0.03 lb/MMBtu for oil/gas steam units (i.e., a 90% reduction with an emission rate floor of 0.05 or 0.03 lb/MMBtu). [25] The adjusted emission rate is multiplied by future year baseline heat input levels to arrive at the future year emissions estimate for that technology. For the units affected by this adjustment, the impact on future year emission assumptions is shown in column AP and flagged in column AQ of the "unit 2023" through "unit 2026" worksheets. Note, this assumption only applies to ozone-season NO_X.

	2021	Future Year (e.g., 2023)
Unit x	10,000 MMBtu x 0.2 lb/MMBtu = 1 ton	10,000 MMBt*u* x 0*.05 lb/MMBtu* = 0.25 *ton*

With all of these unit-level adjustments applied, the resulting unit-level heat input and unit-level emissions are summed up to the state level. This state emissions total is dividied by the state heat input total to derive the state emission rate in the formula below. EPA notes, this emission rate for any given uniform control level times the baseline heat input would provide state-level emissions before generation shifting is incorporated; these state-level emissions are visible in the worksheets titled "State 2023" through "State 2026" in the *Appendix A: Proposed Rule State Emission Budget Calculations and Engineering Analytics* workbook accompanying this document.[26]

State 2023 OS NO_X Budget =
2023 State OS Baseline Heat Input $*[2023\ State\ OS\ NO_X\ Emissions\ Rate\ -$
$(2023\ IPM\ Base\ Case\ OS\ NO_X\ Emissions\ Rate\ -$ 2023 IPM Cost Threshold $OS\ NO_X$ Emissions Rate)]

3. <u>Estimating Emission Reduction Potential from Generation Shifting</u>

The last two variables in the equation relate to emission reductions from generation shifting. Here, as in the Revised CSAPR Update, EPA uses the Integrated Planning Model (IPM) to

[25] By comparison, in the IPM Summer 2021 Reference Case, EPA assumes new SCRs on coal steam units can achieve a 90% reduction in emission with floor rates of 0.05 to 0.07 lb/MMBtu, depending on coal type, and an 80% reduction, with no floor rate, for oil gas steam units. See "Documentation for EPA's Power Sector Modeling Platform v6 using Summer 2021 Reference Case". Available at https://www.https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case

[26] EPA makes these illustrative unit-level details described in B.1 and B.2 available, before aggregating those values to use at the state and regional level. The illustrative unit-level values are meant to be a tool to inform a state-level estimate, not a prediction of how each unit will operate in the future. Although anchored in historical data, EPA recognizes at the unit-level some units will overperform and some units will underperform the unit-level illustrative values.

capture the change in heat input weighted average emission rate in a state's fossil-fuel fired power fleet while holding everything else equal and applying a given dollar per ton marginal cost to ozone-season NO_X emissions.[27] To derive this value, EPA first prepares an adjusted base case that reflects all the combustion or post-combustion mitigation measures discussed above for a given cost threshold. These adjusted base cases are specific to the uniform mitigation scenario. For instance, for the $1,800/ton scenario EPA adjusts its base case to reflect the optimization of SCRs, SNCRs and combustion control upgrades by adjusting the emission rates to the levels discussed above for relevant units not already achieving that level. EPA then executes an IPM run with these new exogenous assumptions and observes the state-level emission rate for fossil-fuel fired units greater than 25 MW. This is the third variable in the emissions budget formula.

Next, EPA performs cost threshold scenarios where, for each cost threshold run, EPA applies the same set of assumptions in the corresponding mitigation measures scenario but layers on a commensurate marginal cost price signal (e.g., $1,800/ton). In addition to the mitigation measures assumed, the entire fossil-fuel fired EGU fleet greater than 25 MW in the state is subjected to a cost-per-ton price associated with those mitigation measures. The model solves for least-cost dispatch given this additional marginal cost for seasonal ozone emissions. In its cost threshold modeling, EPA imposed a minimum generation level in each state covering all EGUs equal to their projected generation level in the IPM base case, such that EPA would not include emission reduction potential for a given state related to increased electricity imported from out-of-state generators.

EPA observes the state-level emission rate for fossil-fuel fired units greater than 25 MW in the applicable cost threshold scenario.[28] This data point becomes the fourth variable in the state-emissions budget formula. The difference between the third and fourth variables reflects the change in emission rate due solely to generation shifting at a given dollar per ton level.

State 2023 OS NO_X Budget =

$$\mathbf{2023}\text{ State OS Baseline Heat Input} * [\mathbf{2023}\ \mathit{State\ OS\ NO_X\ Emissions\ Rate} - (\mathbf{2023}\ \mathit{IPM\ Base\ Case\ OS\ NO_X\ Emissions\ Rate} - \mathbf{2023}\text{ IPM Cost Threshold } \mathit{OS\ NO_X}\text{ Emissions Rate})]$$[29]

This difference in the state-level emission rate between the two IPM cases is shown in columns B and C in the worksheet titled "Generation Shifting".[30] These values are in the *Appendix A: Proposed Rule State Emission Budget Calculations and Engineering Analytics* workbook accompanying this document. Column B provides the "2023" generation shifting emission rate delta pertaining to the $1,800/ton threshold that corresponds to mitigation

[27] EPA relies on IPM for this analysis as generation shifting occurs on a cost continuum and is a function of least-cost dispatch under different constraints.

[28] In each cost threshold run, EPA quantified generation-shifting emission rate changes from the IPM 2023 run-year to avoid capturing generation shifting attributable to model-projected new builds in later years.

[29] The year in the formula changes for each year of budget calculation.

[30] If the state's assumed emission rate reductions from generation shifting were greater than 10% of the IPM baseline, or its adjusted historical baseline for that year was less than 90% of the IPM baseline, then no additional reductions were assumed from generation shifting at the cost threshold of $1,800/ton in EPA's 2023 analysis. If the state's assumed emission rate reductions from generation shifting were greater than 10% of the IPM baseline, or its adjusted historical baseline for that year was less than 90% of the IPM baseline, then reductions consistent with the results from the $1,800/ton analysis were assumed from generation shifting at higher cost thresholds of $10,000/ton ($11,000/ton cost threshold run) in EPA's 2026 analysis.

technologies available in 2023, 2024, and/or 2025. Column C provides the generation shifting emission rate delta pertaining to the $11,000/ton threshold that corresponds to technologies in 2026 and later years. Therefore, column B value is used for state emission calculations in the "2023", "2024", and "2025" state worksheets. Column C value is used in the "2026" worksheet.[31]

Once EPA calculated the change in emissions rate between the IPM adjusted base case and each cost threshold case, the EPA then subtracted this IPM-projected change in emissions rate from the engineering analytics-derived state OS NO_X emission rate (the second variable in the formula). This computation yields state-level, historically-anchored emission rates reflecting NO_X reduction potential for a given control stringency, inclusive of generation shifting at a commensurate representative cost level.

Finally, the EPA multiplied these rates by each state's adjusted heat input (historical heat input adjusted for retirements and new builds identified in variable one of the formula) to yield emission budgets for each cost threshold. The state budgets for the different cost thresholds are displayed in Tables B-2 through B-5.

In addition to being shown below, the state-level emission budgets are calculated in the far right-hand side columns of each "State" worksheet for each mitigation technology scenario available that year. These budgets reflect an application of the formula described above to the data in the spreadsheet. These state-emission budgets reflect the inclusion of generation shifting.

[31] EPA notes the "2025" and "2026" worksheets showing state-level emisison estimates subject to different technologies are illustrative only. The "dynamic budget" worksheet for each year 2025 and beyond is the worksheet used to calculate state-emission budgets for covered states in those future years.

Table B-2. 2023 Ozone Season NO_X Emissions for States at Different Uniform Control Scenarios*

State	2023 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Alabama	6,648	6,616	6,492	6,492	6,261
Arizona	7,723	7,639	7,570	7,439	7,570
Arkansas	8,955	8,927	8,927	8,927	8,889
California	1,606	1,216	1,216	1,216	1,216
Colorado	6,467	6,389	6,389	6,389	6,389
Connecticut	381	355	355	355	355
Delaware	423	388	388	384	388
Florida	13,770	11,339	11,339	11,339	11,339
Georgia	5,514	5,497	5,497	5,490	5,497
Idaho	240	240	240	240	240
Illinois	7,662	7,592	7,592	7,415	7,542
Indiana	12,351	11,495	11,495	11,486	11,160
Iowa	9,072	9,072	9,018	8,958	9,018
Kansas	6,231	5,484	5,484	5,484	5,484
Kentucky	13,900	13,454	12,853	12,853	11,640
Louisiana	9,987	9,408	9,408	9,312	9,408
Maine	108	86	86	86	86
Maryland	1,208	1,208	1,208	1,200	1,195
Massachusetts	297	265	265	265	265
Michigan	10,737	10,733	10,733	10,718	10,733
Minnesota	4,207	4,109	4,109	4,068	3,961
Mississippi	5,097	5,024	4,400	4,400	4,400
Missouri	20,094	12,749	12,749	12,525	12,081
Montana	3,071	3,071	3,071	3,071	3,071
Nebraska	8,931	8,894	8,381	8,381	8,381
Nevada	2,346	2,280	2,280	2,280	2,280
New Hampshire	247	184	184	184	184
New Jersey	915	810	810	810	799
New Mexico	2,289	2,259	2,259	2,259	2,259
New York	3,927	3,863	3,863	3,863	3,763
North Carolina	12,354	9,298	9,298	9,268	9,298
North Dakota	12,246	12,246	12,246	11,436	12,246
Ohio	10,295	9,134	9,134	9,134	8,369
Oklahoma	10,463	10,265	9,573	9,573	9,573
Oregon	337	288	288	288	289
Pennsylvania	12,242	9,364	9,364	9,264	8,955
Rhode Island	279	148	148	148	148
South Carolina	4,273	3,531	3,531	3,531	3,531
South Dakota	568	568	568	568	568
Tennessee	4,319	4,209	4,209	4,209	4,234
Texas	40,860	39,938	39,938	39,706	38,516

State	2023 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Utah	15,500	15,493	15,493	15,493	14,981
Vermont	54	54	54	54	54
Virginia	3,415	3,251	3,174	3,120	3,144
Washington	1,999	1,729	1,729	1,729	1,729
West Virginia	14,686	14,132	13,586	13,306	12,759
Wisconsin	5,933	5,927	5,927	5,907	5,983
Wyoming	10,191	10,110	9,514	9,501	8,543
Total	**334,421**	**310,331**	**306,436**	**304,124**	**298,774**
Linked in 2023	**238,306**	**221,983**	**218,724**	**217,450**	**211,062**
Linked in 2026	**226,916**	**210,771**	**207,635**	**206,365**	**200,179**

Table B-3. 2024 Ozone Season NO_X Emissions for States at Different Uniform Control Scenarios

State	2024 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Alabama	6,701	6,668	6,545	6,545	6,306
Arizona	7,723	7,639	7,570	7,439	7,570
Arkansas	8,955	8,927	8,927	8,927	8,889
California	1,589	1,199	1,199	1,199	1,199
Colorado	5,877	5,799	5,799	5,799	5,799
Connecticut	381	355	355	355	355
Delaware	473	438	438	434	438
Florida	13,097	10,720	10,720	10,720	10,720
Georgia	5,514	5,497	5,497	5,490	5,497
Idaho	240	240	240	240	240
Illinois	7,763	7,694	7,694	7,516	7,640
Indiana	10,525	9,712	9,712	9,703	9,400
Iowa	9,072	9,072	9,018	8,958	9,018
Kansas	6,231	5,484	5,484	5,484	5,484
Kentucky	13,900	13,454	12,853	12,853	11,640
Louisiana	9,987	9,408	9,408	9,312	9,408
Maine	108	86	86	86	86
Maryland	1,208	1,208	1,208	1,200	1,195
Massachusetts	297	265	265	265	265
Michigan	10,737	10,733	10,733	10,718	10,733
Minnesota	4,207	4,109	4,109	4,068	3,961
Mississippi	5,097	5,024	4,400	4,400	4,400
Missouri	20,094	12,749	12,749	12,525	12,081
Montana	3,071	3,071	3,071	3,071	3,071
Nebraska	8,931	8,894	8,381	8,381	8,381
Nevada	2,438	2,372	2,372	2,372	2,372
New Hampshire	247	184	184	184	184
New Jersey	915	810	810	810	799
New Mexico	2,289	2,259	2,259	2,259	2,259
New York	3,927	3,863	3,863	3,863	3,763
North Carolina	12,354	9,298	9,298	9,268	9,298
North Dakota	12,246	12,246	12,246	11,436	12,246
Ohio	10,295	9,134	9,134	9,134	8,369
Oklahoma	10,463	10,265	9,573	9,573	9,573
Oregon	337	288	288	288	289
Pennsylvania	12,242	9,364	9,364	9,264	8,955
Rhode Island	279	148	148	148	148
South Carolina	4,273	3,531	3,531	3,531	3,531
South Dakota	568	568	568	568	568
Tennessee	4,319	4,209	4,209	4,209	4,234
Texas	40,860	39,938	39,938	39,706	38,516
Utah	15,673	15,666	15,666	15,666	15,146
Vermont	54	54	54	54	54

State	2024 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Virginia	3,106	2,942	2,865	2,843	2,836
Washington	1,999	1,729	1,729	1,729	1,729
West Virginia	14,686	14,132	13,586	13,306	12,759
Wisconsin	5,029	5,023	5,023	5,003	5,077
Wyoming	10,249	10,167	9,572	9,559	8,586
Total	**330,627**	**306,634**	**302,739**	**300,459**	**295,067**
Linked in 2023	**235,776**	**219,497**	**216,237**	**214,995**	**208,564**
Linked in 2026	**224,283**	**208,181**	**205,045**	**203,808**	**197,586**

Table B-4. 2025 Ozone Season NO_X Emissions for States at Different Uniform Control Scenarios

State	2025 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Alabama	6,701	6,668	6,545	6,545	6,306
Arizona	7,723	7,639	7,570	7,439	7,570
Arkansas	8,955	8,927	8,927	8,927	8,889
California	1,547	1,157	1,157	1,157	1,157
Colorado	5,877	5,799	5,799	5,799	5,799
Connecticut	381	355	355	355	355
Delaware	473	438	438	434	438
Florida	13,142	10,765	10,765	10,765	10,765
Georgia	5,514	5,497	5,497	5,490	5,497
Idaho	240	240	240	240	240
Illinois	7,763	7,694	7,694	7,516	7,640
Indiana	9,737	9,017	9,017	9,008	8,723
Iowa	9,072	9,072	9,018	8,958	9,018
Kansas	6,231	5,484	5,484	5,484	5,484
Kentucky	13,211	12,765	12,325	12,325	11,134
Louisiana	9,854	9,275	9,275	9,179	9,275
Maine	108	86	86	86	86
Maryland	1,208	1,208	1,208	1,200	1,195
Massachusetts	288	256	256	256	256
Michigan	10,778	10,774	10,774	10,759	10,774
Minnesota	4,197	4,099	4,099	4,058	3,951
Mississippi	5,097	5,024	4,400	4,400	4,400
Missouri	18,610	11,265	11,265	11,041	10,679
Montana	3,071	3,071	3,071	3,071	3,071
Nebraska	8,247	8,210	8,177	8,177	8,177
Nevada	2,438	2,372	2,372	2,372	2,372
New Hampshire	247	184	184	184	184
New Jersey	915	810	810	810	799
New Mexico	2,232	2,201	2,201	2,201	2,201
New York	3,927	3,863	3,863	3,863	3,763
North Carolina	12,228	9,172	9,172	9,162	9,172
North Dakota	12,246	12,246	12,246	11,436	12,246
Ohio	10,295	9,134	9,134	9,134	8,369
Oklahoma	10,283	10,084	9,393	9,393	9,393
Oregon	345	296	296	296	297
Pennsylvania	12,242	9,364	9,364	9,264	8,955
Rhode Island	279	148	148	148	148
South Carolina	4,273	3,531	3,531	3,531	3,531
South Dakota	568	568	568	568	568
Tennessee	4,064	3,983	3,983	3,983	4,008
Texas	39,186	38,265	38,265	38,032	36,851
Utah	15,673	15,666	15,666	15,666	15,146

State	2025 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + Generation Shifting
Vermont	54	54	54	54	54
Virginia	3,243	3,079	3,001	2,980	2,970
Washington	1,999	1,729	1,729	1,729	1,729
West Virginia	14,686	14,132	13,586	13,306	12,759
Wisconsin	4,178	4,171	4,171	4,152	4,217
Wyoming	10,249	10,167	9,572	9,559	8,586
Total	**323,874**	**300,004**	**296,750**	**294,490**	**289,197**
Linked in 2023	**229,853**	**213,697**	**210,599**	**209,357**	**203,046**
Linked in 2026	**218,615**	**202,607**	**199,632**	**198,395**	**192,294**

Table B-5. 2026 Ozone Season NO_X Emissions for States at Different Uniform Control Scenarios

State	2026 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + SCR/SNCR Retrofit	SCR Optimization + SOA CC + SNCR Optimization + SCR/SNCR Retrofit + Generation Shifting
Alabama	6,701	6,668	6,545	6,545	5,785	5,785
Arizona	5,237	5,153	5,084	4,954	3,152	3,152
Arkansas	8,728	8,700	8,700	8,700	4,031	3,923
California	1,547	1,157	1,157	1,157	1,157	1,157
Colorado	5,877	5,799	5,799	5,799	3,482	3,482
Connecticut	381	355	355	355	355	355
Delaware	473	438	438	434	434	434
Florida	13,142	10,765	10,765	10,765	8,041	8,041
Georgia	5,514	5,497	5,497	5,490	5,325	5,325
Idaho	240	240	240	240	240	240
Illinois	7,763	7,694	7,694	7,516	6,465	6,115
Indiana	9,737	9,017	9,017	9,008	7,997	7,791
Iowa	9,072	9,072	9,018	8,958	3,556	3,556
Kansas	6,231	5,484	5,484	5,484	3,394	3,394
Kentucky	13,211	12,765	12,325	12,325	7,761	7,573
Louisiana	9,854	9,275	9,275	9,179	3,752	3,752
Maine	108	86	86	86	86	86
Maryland	1,208	1,208	1,208	1,200	1,200	1,189
Massachusetts	287	256	256	256	256	256
Michigan	9,129	9,125	9,125	9,110	6,170	6,114
Minnesota	4,197	4,099	4,099	4,058	2,584	2,536
Mississippi	5,077	5,004	4,379	4,379	1,913	1,914
Missouri	18,610	11,265	11,265	11,041	7,373	7,246
Montana	3,071	3,071	3,071	3,071	1,177	1,177
Nebraska	8,247	8,210	8,177	8,177	2,974	2,974
Nevada	2,438	2,372	2,372	2,372	1,211	1,211
New Hampshire	247	184	184	184	184	184
New Jersey	915	810	810	810	810	799
New Mexico	2,232	2,201	2,201	2,201	1,712	1,712
New York	3,927	3,863	3,863	3,863	3,338	3,238
North Carolina	12,228	9,172	9,172	9,162	6,467	6,467
North Dakota	12,246	12,246	12,246	11,436	2,927	2,927
Ohio	10,295	9,134	9,134	9,134	8,941	8,586
Oklahoma	10,283	10,084	9,393	9,393	4,315	4,275
Oregon	345	296	296	296	296	304
Pennsylvania	11,738	9,000	9,000	8,901	7,228	6,819
Rhode Island	279	148	148	148	148	148
South Carolina	4,273	3,531	3,531	3,531	3,531	3,531
South Dakota	568	568	568	568	568	568
Tennessee	4,064	3,983	3,983	3,983	3,983	3,983
Texas	39,186	38,265	38,265	38,032	23,369	21,946

State	2026 Baseline (Engineering Analysis)	SCR Optimization	SCR Optimization + SOA CC	SCR Optimization + SOA CC + SNCR Optimization	SCR Optimization + SOA CC + SNCR Optimization + SCR/SNCR Retrofit	SCR Optimization + SOA CC + SNCR Optimization + SCR/SNCR Retrofit + Generation Shifting
Utah	9,679	9,672	9,672	9,672	2,604	2,620
Vermont	54	54	54	54	54	54
Virginia	3,243	3,079	3,001	2,980	2,597	2,567
Washington	1,999	1,729	1,729	1,729	639	639
West Virginia	14,686	14,132	13,586	13,306	11,026	10,597
Wisconsin	3,628	3,622	3,622	3,602	3,575	3,473
Wyoming	10,249	10,167	9,572	9,559	4,580	4,490
Total	**312,443**	**288,714**	**285,461**	**283,201**	**182,758**	**178,705**
Linked in 2023	**220,909**	**204,893**	**201,795**	**200,554**	**134,492**	**130,437**
Linked in 2026	**209,670**	**193,803**	**190,829**	**189,591**	**124,290**	**120,235**

As described in Section VI of the Preamble, EPA identified $11,000/ton as the level of control stringency for determining significant contribution from EGUs under the Step 3 multifactor test. However, EPA determined that retrofitting post-combustion could not be widely accomplished until the 2026 ozone season. Therefore, Section VII explains that EPA applied the reductions available at the $1,800/ton representative cost threshold for years 2023-2025 to arrive at a budget estimate for those years. Then, starting in 2026, EPA applied the reductions available at the $11,000/ton representative cost threshold to arrive at a budget estimate for that year. Those state-level emissions budgets for the affected states along with the corresponding percent reduction relative to 2021 and the state's baseline emissions for that year are shown below in Tables B-6 through B-10.[32]

[32] A table providing state emission budgets and associated variability limits for these linked states is provided in Appendix F

Table B-6. OS NO_X: 2023 Emissions Budget, and % Reduction

State	**2016 OS NO_X (tons)**	**2021 OS NO_X (tons)**	**Baseline 2023 OS NO_X (tons)**	**2023 Budget (tons)**	**% Reduction from 2021**	**% Reduction from 2023 Baseline**
Alabama	11,612	6,648	6,648	6,364	4%	4%
Arkansas	13,223	8,955	8,955	8,889	1%	1%
Delaware	551	423	423	384	9%	9%
Illinois	14,550	11,276	7,662	7,364	35%	4%
Indiana	34,670	14,162	12,351	11,151	21%	10%
Kentucky	25,403	14,571	13,900	11,640	20%	16%
Louisiana	19,615	11,456	9,987	9,312	19%	7%
Maryland	4,471	1,422	1,208	1,187	17%	2%
Michigan	17,632	13,554	10,737	10,718	21%	0%
Minnesota	7,587	5,652	4,207	3,921	31%	7%
Mississippi	7,325	5,790	5,097	5,024	13%	1%
Missouri	25,255	20,388	20,094	11,857	42%	41%
Nevada	2,275	2,457	2,346	2,280	7%	3%
New Jersey	2,463	1,322	915	799	40%	13%
New York	6,534	3,997	3,927	3,763	6%	4%
Ohio	24,205	11,728	10,295	8,369	29%	19%
Oklahoma	12,761	10,470	10,463	10,265	2%	2%
Pennsylvania	31,896	12,792	12,242	8,855	31%	28%
Tennessee	9,759	4,319	4,319	4,234	2%	2%
Texas	54,668	42,760	40,860	38,284	10%	6%
Utah	12,955	15,762	15,500	14,981	5%	3%
Virginia	9,833	3,329	3,415	3,090	7%	10%
West Virginia	21,178	14,686	14,686	12,478	15%	15%
Wisconsin	7,946	6,307	5,933	5,963	5%	0%
Wyoming	15,664	11,643	10,191	9,125	22%	10%
Total	**394,029**	**255,868**	**236,363**	**210,297**	**18%**	**11%**

Table B-7. OS NO_X: 2024 Emissions Budget, and % Reduction

State	2016 OS NO_X (tons)	2021 OS NO_X (tons)	Baseline 2024 OS NO_X (tons)	2024 Budget (tons)	% Reduction from 2021	% Reduction from 2024 Baseline
Alabama	11,612	6,648	6,701	6,306	5%	6%
Arkansas	13,223	8,955	8,955	8,889	1%	1%
Delaware	551	423	473	434	-3%	8%
Illinois	14,550	11,276	7,763	7,463	34%	4%
Indiana	34,670	14,162	10,525	9,391	34%	11%
Kentucky	25,403	14,571	13,900	11,640	20%	16%
Louisiana	19,615	11,456	9,987	9,312	19%	7%
Maryland	4,471	1,422	1,208	1,187	17%	2%
Michigan	17,632	13,554	10,737	10,718	21%	0%
Minnesota	7,587	5,652	4,207	3,921	31%	7%
Mississippi	7,325	5,790	5,097	4,400	24%	14%
Missouri	25,255	20,388	20,094	11,857	42%	41%
Nevada	2,275	2,457	2,438	2,372	3%	3%
New Jersey	2,463	1,322	915	799	40%	13%
New York	6,534	3,997	3,927	3,763	6%	4%
Ohio	24,205	11,728	10,295	8,369	29%	19%
Oklahoma	12,761	10,470	10,463	9,573	9%	9%
Pennsylvania	31,896	12,792	12,242	8,855	31%	28%
Tennessee	9,759	4,319	4,319	4,234	2%	2%
Texas	54,668	42,760	40,860	38,284	10%	6%
Utah	12,955	15,762	15,673	15,146	4%	3%
Virginia	9,833	3,329	3,106	2,814	15%	9%
West Virginia	21,178	14,686	14,686	12,478	15%	15%
Wisconsin	7,946	6,307	5,029	5,057	20%	-1%
Wyoming	15,664	11,643	10,249	8,573	26%	16%
Total	**394,029**	**255,868**	**233,849**	**205,835**	**20%**	**12%**

Table B-8. OS NO_X: Illustrative 2025 Emissions Budget, and % Reduction

State	2016 OS NO_X (tons)	2021 OS NO_X (tons)	Baseline 2025 OS NO_X (tons)	Illustrative 2025 Budget (tons)	% Reduction from 2021	% Reduction from 2025 Baseline
Alabama	11,612	6,648	6,701	6,306	5%	6%
Arkansas	13,223	8,955	8,955	8,889	1%	1%
Delaware	551	423	473	434	-3%	8%
Illinois	14,550	11,276	7,763	7,463	34%	4%
Indiana	34,670	14,162	9,737	8,714	38%	11%
Kentucky	25,403	14,571	13,211	11,134	24%	16%
Louisiana	19,615	11,456	9,854	9,179	20%	7%
Maryland	4,471	1,422	1,208	1,187	17%	2%
Michigan	17,632	13,554	10,778	10,759	21%	0%
Minnesota	7,587	5,652	4,197	3,910	31%	7%
Mississippi	7,325	5,790	5,097	4,400	24%	14%
Missouri	25,255	20,388	18,610	10,456	49%	44%
Nevada	2,275	2,457	2,438	2,372	3%	3%
New Jersey	2,463	1,322	915	799	40%	13%
New York	6,534	3,997	3,927	3,763	6%	4%
Ohio	24,205	11,728	10,295	8,369	29%	19%
Oklahoma	12,761	10,470	10,283	9,393	10%	9%
Pennsylvania	31,896	12,792	12,242	8,855	31%	28%
Tennessee	9,759	4,319	4,064	4,008	7%	1%
Texas	54,668	42,760	39,186	36,619	14%	7%
Utah	12,955	15,762	15,673	15,146	4%	3%
Virginia	9,833	3,329	3,243	2,948	11%	9%
West Virginia	21,178	14,686	14,686	12,478	15%	15%
Wisconsin	7,946	6,307	4,178	4,198	33%	0%
Wyoming	15,664	11,643	10,249	8,573	26%	16%
Total	**394,029**	**255,868**	**227,962**	**200,352**	**22%**	**12%**

Table B-9. OS NO_X: Illustrative 2026 Emissions Budget, and % Reduction

State	2016 OS NO_X (tons)	2021 OS NO_X (tons)	Baseline 2026 OS NO_X (tons)	Illustrative 2026 Budget (tons)	% Reduction from 2021	% Reduction from 2026 Baseline
Alabama	11,612	6,648	6,701	6,306	5%	6%
Arkansas	13,223	8,955	8,728	3,923	56%	55%
Delaware	551	423	473	434	-3%	8%
Illinois	14,550	11,276	7,763	6,115	46%	21%
Indiana	34,670	14,162	9,737	7,791	45%	20%
Kentucky	25,403	14,571	13,211	7,573	48%	43%
Louisiana	19,615	11,456	9,854	3,752	67%	62%
Maryland	4,471	1,422	1,208	1,189	16%	2%
Michigan	17,632	13,554	9,129	6,114	55%	33%
Minnesota	7,587	5,652	4,197	2,536	55%	40%
Mississippi	7,325	5,790	5,077	1,914	67%	62%
Missouri	25,255	20,388	18,610	7,246	64%	61%
Nevada	2,275	2,457	2,438	1,211	51%	50%
New Jersey	2,463	1,322	915	799	40%	13%
New York	6,534	3,997	3,927	3,238	19%	18%
Ohio	24,205	11,728	10,295	8,586	27%	17%
Oklahoma	12,761	10,470	10,283	4,275	59%	58%
Pennsylvania	31,896	12,792	11,738	6,819	47%	42%
Tennessee	9,759	4,319	4,064	4,008	7%	1%
Texas	54,668	42,760	39,186	21,946	49%	44%
Utah	12,955	15,762	9,679	2,620	83%	73%
Virginia	9,833	3,329	3,243	2,567	23%	21%
West Virginia	21,178	14,686	14,686	10,597	28%	28%
Wisconsin	7,946	6,307	3,628	3,473	45%	4%
Wyoming	15,664	11,643	10,249	4,490	61%	56%
Total	**394,029**	**255,868**	**219,017**	**129,522**	**49%**	**41%**

Table B-10. Emission Reduction Attributable to Generation Shifting (2025 and 2026 are illustrative).

	Baseline OS NOx	Budget Without Gen Shifting	Budget With Gen. Shifting	% Reduction from Generation Shifting as a Percentage of Baseline
2023	236,363	217,961	210,297	3%
2024	233,849	213,509	205,835	3%
2025	227,962	207,906	200,352	3%
2026	219,017	133,802	129,522	2%

4. Variability Limits

Once EPA determined state-emission budgets representative of the proposed control stringency, EPA calculated the variability limits and assurance levels for each state based on the calculated emission budgets. Each state's variability limit is was assumed to be 21% of its budget, and its assurance level is the sum of its budget and variability limit (or 121% of its budget).[33] The variability limits and assurance levels are further described and shown in section VII of the preamble for this rule and shown in Table Appendix F-1.

5. Calculating Dynamic Budgets Starting in 2025

The dynamic budgets methodology for 2025 and subsequent years begins with the engineering analysis used to determine the preset 2024 state budgets and the illustrative 2026 state emissions budgets described above. There are three substantive changes made to the budget calculation. First, the inventory of existing units in the group 3 program is updated to reflect new units not known at the time of final rule. Second, the heat input value for individual units is updated to reflect the latest reported data. Whereas the illustrative budgets rely on 2021 heat input data as its basis for estimating future EGU operation levels in future years, the dynamic budget would substitute in the most recent reported heat input data (e.g., 2023 would be used for 2025 budgets). Finally, the dynamic budget calculation would omit any estimation of generation shifting based reductions as that would be captured through the incorporation of new heat input data (and corresponding dynamic budget calculations). The methodology to derive the dynamic budgets is explained below.[34]

[33] As described in Section VII of the Preamble for this rule, the EPA is proposing a variability limit of 21% for 2023 and 2024. Starting in 2025, the variability limit would be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. EPA expects that the minimum 21 percent value would apply in almost all instances.

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

Appendix A: State Emissions Budget Calculations and Engineering Analytics has a worksheet titled "Dynamic Budget 2025 Template" and another titled "Dynamic Budget 2026+ Template". These worksheets don't show budgets for those future years, but provide the mechanics and data fields(some of which are prepopulated if the data point is fixed, some are left blank if to be populated with future data) to demonstrate how EPA intends to calculate dynamic budgets for a future year. These worksheets reflect: 1) the initial inventory of EGUs used to derive the ozone season state emissions budget for each year 2025 and thereafter, 2) the prepopulated unit-level emission rate and entry space for future heat input data used to estimate unit-level emissions, and 3) the template for summation of the unit-level emission estimates to identify the states dynamic budget for a future year (omitting any additional generation shifting assumption used in the illustrative budgets).

Inventory of EGUs for determining dynamic budget

- The unit name and corresponding facility detail such as state, ORIS, Boiler, Plant Type are listed in columns A through P of the "dynamic budget 2025" and "dynamic budget 2026+" worksheet
- The inventory of units is comprised of:
  - The inventory of units included in the "unit 2024 file" for Group 3 states. These are all of the existing units assumed during rule promulgation at the time of the last preset budget year (i.e., 2024). (Note – any unit that subsequently retires is effectively nulified in the calculations as its heat input value is adjusted to zero in steps below)
  - New units that were not included in the "unit 2024 file", but that commenced operation and had a deadline for certification of monitoring systems under §97.1030(b) by May1st of the latest year of historical data (e.g., by May 1st of 2023 for the 2025 state budget calculation). EPA will rely on reported CAMD Power Sector Emissions data to identify these units.

Unit-level emission rate, heat input, and emissions data for dynamic budget

- For each of the units identified in the above inventory, EPA populates a pre-determined emission rate. Where available, this rate comes directly from the unit-files described above and used in the pre-determined and illustrative budget calculations. EPA applies the emission rate reflecting the selected control stringency identified and applied for those illustrative state budgets. For the "dynamic budget 2025" worksheet, these emission rates come from column AR in the "unit 2024" worksheet, which are calculated by dividing the unit-level emissions value from column AN into the unit-level heat input value from column Z in the "unit 2024" worksheet.[35] The use of the "unit 2024 file" emission rate value is consistent with the notion that no additional mitigation measures are assumed in 2025. These unit-level emission rate reflects the control stringency identified in EPA's determination of significant contribution applied to these units in

[35] This emissions value is multiplied by 2000 to convert tons to pounds. Therefore, the emission rate is expressed in a lb/MMBtu metric.

2025. For the “dynamic budget 2026+” worksheet, these emission rates come from column AS in the “unit 2026” worksheet, which are calculated by dividing the unit-level emissions value from column AP into the unit-level heat input value from column Z in the “unit 2026” worksheet. This value is also shown in column AS in the “unit 2026” worksheet. The “unit 2026” worksheet reflects the lower emission rate for some units where post-combustion control retrofit potential is identified.[36]

- There are two types of units (new units, and 2021 non-operating units) for which the above step would not yield an assumed emission rate. Therefore, EPA populates an assumed emission rate based on the following:

  - For new units, EPA applies the following assumed emission rates for well controlled units identified for each generation type as discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD:

Applied New Unit Emission Rates for Dynamic Budgets

Unit Type	**Assumed Emission Rate (lb/MMBtu)**
Coal Steam	0.05
Oil/Gas steam	0.03
Combustion Turbine	0.03
Combined Cycle	0.012
All other fossil	0.05

  - For 2021 non-operating units (and thus no identified emission rate in the “unit 2024” file), EPA applies an emission rate based on that unit’s last year in which it had ozone season operating data prior to 2021. If that rate exceeds the assumed step 3 technology in effect for that year (e.g., SCR optimization in 2025 for a coal steam unit with an existing SCR), then the emission rate will be adjusted down to that level (e.g., 0.08 lb/MMBtu). If these units have no operating data from a prior ozone season, than they would be assigned rates according to the table above.
- These corresponding emission rates for all units are shown in column Q of the “dynamic budget 2025” and “dynamic budget 2026+” worksheet.
  - This step is completed at the time of promulgation of this rulemaking, and therefore these rates (reflecting the removal of significant contribution) are determined and published in the rule’s promulgation. This variable is not dynamic.
- Column R in the “dynamic budget” worksheet will reflect the updated heat input for the units as it becomes available. This is the dynamic variable, and it will be populated through future ministerial actions. For instance, this column would be populated with

[36] The emission rate for Alabama, Delaware, and Tennessee continue to be identified by column AR, rather than AS, at this step as those states are not subject to the post-combustion control stringency assumptions

reported 2023 heat input for the "dynamic budget 2025" worksheet (as 2023 data will be the latest available data at the time of deriving the 2025 budget). For the "dynamic budget 2026+" worksheet, this column will be populated with the latest reported heat input value for the identified unit for each budget year 2026 and beyond. When applied to derive 2026 budgets, this column would be populated with reported 2024 heat input data, when applied to derive 2027 budgets it would be populated with reported 2025 heat input data, and so forth.

  - Any unit included in the inventories identified for "dynamic budget 2025" and "dynamic budget 2026+" worksheets for which reported heat input data from the most recent historical year is not available due to the fact that the unit was not yet monitoring and reporting at the start of that data year (e.g., 2023), then EPA will continue to rely on the same heat input value used in the "unit 2024" worksheet.

- Column S reflects the unit-level assumed emissions. This value will be obtained by multiplying the emission rate (in column Q) by the heat input value (column R). The product is divided by 2,000 to convert from pounds to short tons.

Summation of the unit-level emission estimates to derive the given year's dynamic budget

After completing the above steps, the unit-level emission values that will be identified in column S of each "dynamic budget" worksheet are summed to the state level. These states (those 25 covered for EGU Group 3 under this action) and state-level values (in tons) are displayed in columns Y and Z of the same "dynamic budget" worksheet. These tonnage values in column Z reflect the state budgets for the given year (starting in 2025). At this step, a rounding fuction is applied to express the values to the nearest ton. These state tonnage totals (i.e., budgets) are made public and implemented approximately 1 year prior to their vintage year (e.g., 2025 budgets will be announced prior to the summer of 2024) through the schedule identified in Section VII of the preamble.

C. Analysis of Air Quality Responses to Emission Changes Using an Ozone Air Quality Assessment Tool (AQAT)

EPA has defined each linked upwind state's significant contribution to nonattainment and interference with maintenance of downwind air quality using a multi-factor test (described in the preamble at section VI.B-D applying Step 3 of the 4-Step Good Neighbor Framework) which is based on cost, emissions, and air quality factors. A key quantitative input for determining the amount of each state's emission reduction obligation is the predicted downwind ambient air quality impacts of the various levels of NO_X emission control assessed for upwind EGU and non-EGU sources. See sections A and B of this TSD for information regarding EGUs and see preamble section VI.B.2 and VI.C.2 and the Non-EGU Screening Assessment TSD for information about non-EGUs. The emission reductions associated with the various cost thresholds analyzed for this proposed rule are expected to result in different amounts of air quality improvement at the downwind receptors. The downwind air quality impacts are used to inform EPA's assessment of potential overcontrol, as discussed in more detail below.

Air quality modeling would be the optimal way to estimate the air quality impacts at each cost threshold level from EGUs and non-EGUs emissions reductions. However, due to time and resource limitations EPA was unable to use photochemical air quality modeling for all but a few emissions scenarios. Therefore, in order to estimate the air quality impacts for the various levels of emission reductions and to ensure that each step of its analysis is informed by the evolving emissions data, EPA used a simplified air quality assessment tool (AQAT).[37] The simplified tool allows the Agency to analyze many more levels of NO_X control stringency as implemented through emission budgets than would otherwise be possible. EPA recognizes that AQAT is not the equivalent of photochemical air quality modeling but in the Agency's view is adequate to this purpose. AQAT is directly informed by air quality modeling data. Further, AQAT has evolved through iterative development under the original CSAPR, the CSAPR Update, and the Revised CSAPR Update. One such evolution is its calibration of the change in air quality based on air quality modeling of a particular emission reduction scenario. Here, EPA continues the development of the AQAT to make state and receptor specific calibration factors, rather than just receptor specific calibration factors. EPA examined one of the cost threshold scenarios for the year 2026 using two different calibration factors as a mechanism to estimate the range of results. The inputs and outputs of the tool can be found in the "Ozone_AQAT_Proposal.xlsx" excel workbook.[38]

The remainder of section C of this document will:

- Present an introduction and overview of the ozone AQAT;
- Describe the construction of the ozone AQAT; and
- Provide the results of the NO_X emission cost threshold analyses.

1. Introduction

The ozone AQAT was developed for use in the step 3 air quality analysis as part of the multi-factor test. Specifically, the AQAT was designed to evaluate air quality changes in response to emissions changes in order to quantify necessary emission reductions under the good neighbor provision and to evaluate potential levels of emission control stringency as implemented through budgets for over-control as to either the 1% threshold or the downwind receptor status. EPA described and used a similar tool in the original CSAPR to evaluate good neighbor obligations with respect to the fine particulate matter ($PM_{2.5}$) NAAQS and in both the CSAPR Update and final Revised CSAPR Update to evaluate good neighbor obligations with respect to ozone. For the CSAPR Update, EPA refined both the construction and application of the assessment tool for use in estimating changes in ozone concentrations in response to changes in NO_X emissions. This methodology was reapplied in the Revised CSAPR Update. Here, we extend the methodology developed in the CSAPR Update rulemaking and calibrate the response

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[37] EPA used CAMx to model several base cases (i.e., one of 2016, one of 2023, and one of 2026). The EPA calculated air quality contributions for each state for both the 2023 and 2028 cases. EPA also modeled a 2026 case with air quality contributions where EGU and non-EGU emissions were uniformly reduced by 30%.
[38] The AQAT estimates in the workbook are based on EGU emission estimates completed on December 7, 2021 and may not represent the final emission estimates used in the rule.

of a pollutant using two CAMx simulations at different emission levels where we have full sets of state level emissions and contribution data.[39,40]

A critical factor in the assessment tool is the establishment of a relationship between ozone season NO_X emission reductions and reductions in ozone. Within AQAT, on a state-by-state and receptor-by-receptor basis, we assume that the reduction of a ton of emissions of NO_X from the upwind state results in a particular level of improvement in air quality downwind.[41] For the purposes of developing and using an assessment tool to compare the air quality impacts of NO_X emission reductions under various emission cost threshold emission levels, we determine the relationship between changes in emissions and changes in ozone contributions on a state-by-state and receptor-by-receptor basis. Specifically, EPA assumed that, within the range of total NO_X emissions being considered (as defined by the cost threshold emission levels or changes from year-to-year), a change in ozone season NO_X emissions leads to a proportional change in downwind ozone contributions.[42] This proportional relationship was then modified using calibration factors created based on state-specific source apportionment (i.e., contribution) air quality modeling of 2023 and 2026 base case emissions and a sensitivity scenario in which 2026 base case EGU and non-EGU NO_X emissions were reduced by 30% in each state. The contributions from the 2026 30% NO_X reduction case were applied for cases that examine EGU or non-EGU emissions reductions, whereas, the 2023 and 2026 base case contribution modeling results were applied for estimating ozone design values for additional future years, as necessary, that were not modeled explicitly. The calibration factors are designed to adjust the response of ozone to emissions changes to reflect the non-linear, non-one-to-one proportional relationship between changes in NO_X emissions and the associated changes in ozone. For example, for a particular state and receptor in 2026, we could assume that a 20% decrease in the upwind state's emissions leads to a 20% decrease in its downwind ozone contribution in the "uncalibrated" ozone AQAT, while following the application of the calibration factor (based on the change to

[39] In CSAPR, we estimated changes in sulfate using changes in SO_2 emissions.

[40] In this rule, we used CAMx to calibrate the assessment tool's predicted change in ozone concentrations to changes in NO_X emissions. This calibration is state and receptor-specific and is based on the changes in NO_X emissions and resulting ozone concentrations between the 2026 base case and a 2026 control scenario where EGU and non-EGU emissions were simultaneously reduced by 30%. For time periods before or after 2026, we used the an alternative state and receptor-specific calibrations using the state and receptor specific differences in air quality contributions and emissions between the 2026 base case and the 2023 base case.

[41] This downwind air quality improvement is assumed to be indifferent to the source sector or the location of the particular emission source within the state where the ton was reduced. For example, reducing one ton of NO_X emissions from the power sector is assumed to have the same downwind ozone reduction as reducing one ton of NO_X emissions from the non-EGU source sector. Similarly, when we are using the alternative calibration factors we assume that reducing a ton of emissions from the power sector has the same effect as reducing a ton of emissions from the mobile source sector.

[42] The relationship between NO_X emissions and ozone concentrations is known to be non-linear when examined over large ranges of NO_X emissions (e.g., J.H. Seinfeld and S.N. Pandis, Atmospheric Chemistry and Physics From Air Pollution to Climate Change, 2nd Edition, John Wiley and Sons, 2006, Hoboken, NJ, pp 236-237). However, for smaller ranges of NO_X and VOC emissions, while meteorological conditions are held constant, the relationship may be reasonably linear. The nonlinearities are evident over tens of ppb of ozone changes with tens of percent changes in the overall emission inventories. For most states examined here, under the various control scenarios, most changes in the emission inventory are on the order of a few percent and most air quality changes are on the order of a fraction of a ppb. In this assessment tool, we are assuming a linear relationship between NO_X emissions and ozone concentrations calibrated between two CAMx simulations. A significant portion of the nonlinearity is accounted for by using the calibration factors and having the air quality estimates occur at levels of emissions between the 2026 base case and the other case used in the calibration (which were both modeled in CAMx).

the 2026 30% reduction from EGU and non-EGU sources) it may only decrease by 10% in "calibrated" AQAT (where the calibration factor is 0.5). Typically, the calibration factors were substantially less than one for the state containing the receptor, often on the order of 0.3 (thus, a 10% decrease in emissions from a particular state would result in a 3% decrease in the ozone contribution from that state) and then increased with states that are farther upwind to values around 1 (where a 10% reduction in emissions would result in a 10% decrease in ozone contribution from the particular state). The reason for this relationship is the difference in chemical state for the emissions as they cycle between NO_X and ozone as they encounter various oxidative/reductive chemical regimes and meteorological conditions as they are transported. The creation of the calibration factors is described in detail in section C.2.c (1) of this TSD.

Section C.2, below, is a technical explanation of the construction of the ozone AQAT. Readers who prefer to access the results of the analysis using the ozone AQAT are directed to section C.3.

2. Details on the construction of the ozone AQAT for this proposed rule

(a) Overview of the ozone AQAT

This section describes the step-by-step development process for the ozone AQAT. All the input and output data can be found in the Excel worksheets described in Appendix B. In the ozone AQAT, EPA links state-by-state NO_X emission reductions (derived from the photochemical model, the non-EGU assessment and/or the IPM EGU modeling combined with the EGU engineering assessment) with 2026 CAMx modeled ozone contributions in order to predict ozone concentrations at different levels of emission levels at monitoring sites. The reduction in state-by-state ozone contributions for each year at each cost threshold level and the resulting air quality improvement at monitoring sites with projected nonattainment and/or maintenance problems were then considered in a multi-factor test for identifying the level of emissions reductions that define significant contribution to nonattainment and interference with maintenance.

In applying AQAT to analyze air quality improvements at a given receptor for the cost threshold scenarios, emissions were reduced in only those upwind states that were "linked" to that receptor in step 2 of the Good Neighbor Framework (i.e., those states that contributed an air quality impact at or above 1 percent of the NAAQS). Emissions were also reduced in the state that contained that receptor (regardless of the level of that state's contribution or whether that state was linked to another state) at a level of control stringency consistent with the stringency level applied in upwind states.[43]

[43]Here, EPA assumes that the downwind state will implement (if it has not already) an emissions control strategy for their sources that is of the same stringency as each upwind control strategy examined here. Under this approach, EPA accounts for what may be considered the downwind state's "fair share." As discussed in the preamble, Section VII.D, EPA no longer believes it is a necessary part of the "overcontrol" analysis to account for the downwind state's "fair share." In this regard, we present results in this TSD both with emissions reductions in unlinked home states (called the "scenario" estimates) and without this assumption (called the "control" estimates). At each receptor under the "scenario" estimates we only consider the impact of emissions reductions from upwind states that were linked to that particular receptor while for the "control" estimates we consider the impact of emissions reductions that are linked to any receptor.

Specifically, the key estimates from the ozone AQAT for each receptor are:

- The ozone contribution as a function of emissions at each cost threshold level, for each upwind state that is contributing above the 1 percent air quality threshold and the state containing the receptor.
- The ozone contribution under base case NO_X emissions in the various years, for each upwind state that is not above the 1 percent air quality threshold for that receptor.
- The non-anthropogenic (i.e., background, boundary, biogenic, and wildfire) ozone concentrations. These are assumed to vary linearly in direct proportion to the total anthropogenic contribution change relative to the total change in these components between the 2026 base case source apportionment modeling and the 2026 30% EGU and non-EGU source apportionment modeling scenario.

The results of the ozone AQAT analysis for each emission cost threshold level for EGUs and non-EGUs can be found in section C.3 of this document.

<u>(b) Data used to construct the ozone AQAT for this rule</u>

Several air quality modeling and emissions inventory sources were used to construct the calibrated ozone AQAT for this rule. As described in the Air Quality Modeling TSD, EPA performed contribution modeling for 2023 and 2026 using base case emissions to quantify the amount of ozone formed from several source "tags". In the modeling for both 2023 and 2026, EPA tagged anthropogenic emission in each state individually as well as total anthropogenic emissions in Canada and Mexico combined, emissions from offshore drilling platforms and shipping, emissions from wild and prescribed fires, biogenic emissions, and boundary conditions which represent the net contribution from all sources outside the modeling domain. In addition, EPA also performed state-specific contribution modeling for a 2026 scenario in which EGU and Non-EGU NO_X emissions were reduced by 30 percent. Note that the 2026 base case emissions for air quality modeling used IPM emission estimates while the 2016 base year used EGU continuous emissions monitoring system (CEMS) data. In the ozone AQAT, any emission differences between the 2026 air quality modeling base case and the scenario would result in changes in air quality contributions and ozone concentrations at the downwind monitors. The emission inventories used in the air quality modeling for the 2023 and 2026 base case are discussed in the Preparation of Emissions Inventories for 2016v2 North American Emissions Modeling Platform TSD. An additional emission scenario in which 2026 base case EGU and non-EGU emissions were reduced by 30% was also modeled with state-by-state source apportionment (see the Air Quality Modeling TSD for details). Finally, for each of the EGU and non-EGU scenarios examined with AQAT, the EGU and non-EGU emissions that were modeled were replaced with a 2026 EGU and non-EGU emission inventory used within Step 3. The ozone season NO_X EGU and non-EGU emissions for each emission scenario including the base case as modeled in AQAT are described in section C of this TSD.

<u>(c) Detailed outline of the process for constructing and utilizing the ozone AQAT</u>

The ozone AQAT was created and used in a multi-step process. In brief, ozone AQAT was created using the contributions and emission inventory from the 2023 and 2026 base case air quality modeling as well as the 2026 30% NO_X reduction case to evaluate all policy scenarios. As a first step, EPA developed calibration factors to (1) estimate ozone concentrations in future years that were not simulated with air quality modeling and (2) account for the nonlinear response of ozone to NO_X reductions. Ozone concentrations for alternative years were, while not evaluated at proposal would be based on calibration factors based on the change in ozone concentrations and contributions between the 2026 base case and the 2023 base case. These calibration factors are included as a sensitivity analysis (described later). To calculate the expected change in ozone for each emissions cost threshold scenario evaluated, EPA identified the fractional change in anthropogenic NO_X emissions relative to the 2026 base case in each state and then multiplied this fractional change by the state and receptor-specific calibration factor as well as by the state- and receptor-specific contribution. This resulted in a state- and receptor-specific "calibrated change in contribution" relative to the 2026 base case. Each state's change in contribution value was then added its 2026 base case contribution and the results summed for all states for each receptor.[44] Next, the receptor-specific base case contributions from the other source-categories[45] were added to the sum of each state's contribution. Note that the contributions from these other source categories were modified by the ratio of the total change in anthropogenic contribution from the 2026 base by the total difference between the 2026 base and the 2026 30% reduction scenario to account for the interaction between changes in US anthropogenic emissions and ozone principally formed from these other categories. The net result of these calculations is an estimated design value for each receptor that reflects the emissions changes associated with each scenario evaluated.[46]

The calibrated ozone AQAT was used to project the ozone concentrations for each level of NO_X control stringency as implemented through emission budgets on a state-by-state and receptor-by-receptor basis for every monitor throughout the modeling domain.

(1) Steps to create the calibration factors

The process for creating the calibration factors follows the basic premise of the approach used in the CSAPR Update and Revised CSAPR Update, but is updated to make the factors state as well as receptor specific.

EPA summed the ozone season total anthropogenic NO_X emissions across all relevant source sectors for both the 2026 30% EGU and non-EGU NO_X reduction case and the 2023 base case. EPA calculated the ratio of the anthropogenic emissions for each of these two cases to the total anthropogenic emissions for the 2026 base case for each state modeled in CAMx. More information on the emissions inventories can be found in the preamble to the proposed rule. The total anthropogenic emissions data and resulting fractional reduction ratios can be found in Table C-1 and in the ozone AQAT worksheet "calib_emiss". The difference in emissions in the

[44] In some cases (where emissions are lower than modeled in the 2026 base case) the change in contribution can be negative.
[45] The other source categories include contributions from anthropogenic emission in Canada and Mexico, emissions from offshore drilling platforms and shipping, emissions from wild and prescribed fires, biogenic emissions, and boundary conditions which represent the net contribution from all sources outside the modeling domain.
[46] Details on procedures for calculating average and maximum design values can be found in the Air Quality Modeling TSD.

fractional reduction ratio is the OS anthropogenic NO_X emissions in the 2026 30% NO_X reduction case minus the OS NO_X in the 2026 base case. This difference in tons is then divided by the 2026 base case emissions, resulting in a “fractional reduction” for the 30% NO_X reduction case (Table C-1). A similar procedure was used to get the fractional reduction ratio for the 2023 base case (except the 30% NO_X reduction anthropogenic emissions were replaced by the 2023 base case anthropogenic emissions).

In order to facilitate understanding the next steps of the calibration process, EPA describes below a demonstrative example: the Westport monitor number 090019003 in Fairfield County, Connecticut, with a 2026 base case projected ozone average design value of 74.6 parts per billion (ppb) and maximum design value of 74.8 ppb. The air quality modeling contributions for this receptor for the various modeled cases are included in Table C-1.

For each monitor, the “uncalibrated” change in contribution from each upwind state (Table C-2 for Westport) was found by multiplying each state’s 2026 base case ozone contribution (Table C-1 for Westport) by the reduction fraction ratio (i.e., thedifference in emissions as a fraction of the 2026 base case emissions). The fractional reduction ratios are found in Table C-1. The equation for these calculations is shown in equation 1 for the 30% NO_X case. Equation 1 was also used for developing calibration factors based on 2023, except that the 2023 base case emissions were used instead of the 2026 NO_X reduction emissions.

Uncalibrated delta contribution = 2026 contribution x ((2026 30 NO_X case anthropogenic emissions – 2026 base case anthro emissions)/2026 base case anthropogenic emissions) Eqn C-1

Thus, when the 2026 30% NO_X reduction case or 2023 base case had lower emissions than the 2026 base case, the net result was a negative number. Each state’s reduction fractional change in emissions was multiplied by its 2026 base case contribution to get a state and receptor-specific change in contribution (Table C-2). For each state for each monitor, this change in concentration is total “uncalibrated” change in concentration.

Table C-1. The Total Anthropogenic 2026 Base Case, 2026 w/30% EGU and non-EGU Reduction, and 2023 Base Case NO_X Emissions used in the Modeling and Ozone Contributions (ppb) for the Westport Monitor Number 090019003 in Fairfield County, Connecticut.

State	Modeled 2026 Base Case NO_X Emissions	Modeled 2026 30% EGU/non-EGU Reduction NO_X Emissions	Modeled 2023 Base Case NO_X Emissions	2026 30% NO_X Reduction vs 2026 Base Case Fractional Reduction in Emissions	2023 Base Case vs 2026 Base Case Fractional Reduction in Emissions	Westport 2026 Base Case Ozone Contributions	Westport 2026 30% NO_X Cut Ozone Contributions	Westport 2023 Base Case Ozone Contributions
Alabama	61,759	52,853	66,312	-0.14	0.07	0.106	0.095	0.111
Arizona	33,463	32,313	38,612	-0.03	0.15	0.013	0.013	0.015
Arkansas	39,488	35,333	43,202	-0.11	0.09	0.136	0.126	0.148
California	133,629	127,270	139,593	-0.05	0.04	0.033	0.032	0.034
Colorado	49,825	45,877	53,121	-0.08	0.07	0.055	0.052	0.058
Connecticut	10,887	10,256	11,820	-0.06	0.09	2.861	2.879	2.959
Delaware	6,447	6,135	6,878	-0.05	0.07	0.423	0.410	0.431
District of Columbia	1,302	1,245	1,390	-0.04	0.07	0.037	0.036	0.038
Florida	92,166	84,786	100,080	-0.08	0.09	0.063	0.058	0.067
Georgia	60,266	55,302	67,589	-0.08	0.12	0.140	0.133	0.154
Idaho	17,321	16,296	19,622	-0.06	0.13	0.027	0.026	0.030
Illinois	91,069	83,536	97,086	-0.08	0.07	0.512	0.490	0.530
Indiana	68,291	59,091	73,491	-0.13	0.08	0.716	0.671	0.760
Iowa	41,049	36,033	46,836	-0.12	0.14	0.109	0.101	0.122
Kansas	59,107	53,798	62,587	-0.09	0.06	0.095	0.090	0.099
Kentucky	50,887	43,739	54,506	-0.14	0.07	0.802	0.721	0.830
Louisiana	100,361	86,348	103,038	-0.14	0.03	0.250	0.225	0.256
Maine	12,918	11,982	14,097	-0.07	0.09	0.016	0.016	0.017
Maryland	23,671	22,513	25,735	-0.05	0.09	1.088	1.063	1.140
Massachusetts	26,353	25,321	28,105	-0.04	0.07	0.298	0.293	0.308
Michigan	75,940	66,736	80,760	-0.12	0.06	0.881	0.815	0.922
Minnesota	55,972	49,439	62,656	-0.12	0.12	0.137	0.124	0.148
Mississippi	33,156	29,336	34,435	-0.12	0.04	0.095	0.088	0.100
Missouri	67,664	60,958	76,251	-0.10	0.13	0.284	0.264	0.312
Montana	25,642	23,333	28,408	-0.09	0.11	0.074	0.068	0.081
Nebraska	38,322	34,126	43,826	-0.11	0.14	0.059	0.055	0.066
Nevada	16,178	14,980	18,286	-0.07	0.13	0.011	0.010	0.012
New Hampshire	6,719	6,596	7,287	-0.02	0.08	0.096	0.096	0.103
New Jersey	31,805	30,607	34,476	-0.04	0.08	8.550	8.609	8.855
New Mexico	62,210	58,527	65,186	-0.06	0.05	0.048	0.046	0.050
New York	65,642	61,970	69,960	-0.06	0.07	14.186	14.100	14.365
North Carolina	51,986	46,303	58,908	-0.11	0.13	0.388	0.359	0.438
North Dakota	55,294	52,126	59,167	-0.06	0.07	0.098	0.094	0.103
Ohio	78,681	70,003	85,480	-0.11	0.09	1.787	1.663	1.901
Oklahoma	83,411	76,046	90,114	-0.09	0.08	0.146	0.137	0.154
Oregon	29,345	27,680	33,155	-0.06	0.13	0.028	0.027	0.031
Pennsylvania	103,565	95,081	107,022	-0.08	0.03	6.829	6.450	6.905
Rhode Island	4,187	4,011	4,559	-0.04	0.09	0.043	0.042	0.045
South Carolina	38,939	34,839	43,650	-0.11	0.12	0.154	0.144	0.169
South Dakota	11,084	10,494	12,972	-0.05	0.17	0.037	0.036	0.043
Tennessee	47,475	43,303	52,389	-0.09	0.10	0.253	0.241	0.275
Texas	280,717	261,613	305,019	-0.07	0.09	0.496	0.475	0.536
Utah	29,762	26,807	35,692	-0.10	0.20	0.029	0.027	0.034
Vermont	3,378	3,363	3,853	0.00	0.14	0.025	0.025	0.028
Virginia	46,496	43,302	50,590	-0.07	0.09	1.131	1.092	1.194
Washington	47,754	45,338	53,412	-0.05	0.12	0.047	0.046	0.053
West Virginia	39,500	35,285	43,830	-0.11	0.11	1.233	1.134	1.342
Wisconsin	41,032	37,456	45,503	-0.09	0.11	0.154	0.146	0.165
Wyoming	32,928	28,322	34,211	-0.14	0.04	0.068	0.061	0.070
Tribal Data	4,052	3,352	4,057	-0.17	0.00	0.002	0.002	0.002

Table C-2. The Uncalibrated Ozone Change (ppb) between the 2026 Base Case and the 2026 w/30% EGU and non-EGU Reduction Case and the 2023 Base Case, Along with the Change in Ozone (ppb) from the Air Quality Modeling, as well as the Resulting State-specific Calibration Factors for the Westport Monitor Number 090019003 in Fairfield County, Connecticut.

State	Uncalibrated OzoneChange (2026 to 2026 w/ 30% Cut)	Uncalibrated Ozone Change (2026 to 2023 Base)	Modeled Ozone Change (2026 to 2026 w/ 30% Cut)	Modeled Ozone Change (2026 to 2023 Base)	Calibration Factor for EGUs and non-EGUs (Ratio of Modeled Ozone Change to Uncalibrated Ozone Change 2026 to 2026 w/ 30% Cut)	Calibration Factor for Adjusting Years (Ratio of Modeled Ozone Change to Uncalibrated Ozone Change 2026 to 2023 Base)
Alabama	-0.015	0.008	-0.010	0.005	0.67	0.69
Arizona	0.000	0.002	0.000	0.002	0.60	0.81
Arkansas	-0.014	0.013	-0.010	0.011	0.70	0.89
California	-0.002	0.001	-0.001	0.001	0.68	0.92
Colorado	-0.004	0.004	-0.004	0.003	0.85	0.84
Connecticut	-0.166	0.245	0.018	0.098	-0.11	0.40
Delaware	-0.020	0.028	-0.013	0.008	0.63	0.27
District of Columbia	-0.002	0.003	-0.001	0.001	0.56	0.26
Florida	-0.005	0.005	-0.005	0.004	0.89	0.75
Georgia	-0.012	0.017	-0.007	0.013	0.62	0.78
Idaho	-0.002	0.004	-0.001	0.003	0.59	0.90
Illinois	-0.042	0.034	-0.022	0.018	0.52	0.53
Indiana	-0.096	0.055	-0.045	0.044	0.47	0.81
Iowa	-0.013	0.015	-0.009	0.013	0.64	0.83
Kansas	-0.009	0.006	-0.005	0.004	0.58	0.64
Kentucky	-0.113	0.057	-0.082	0.028	0.73	0.48
Louisiana	-0.035	0.007	-0.025	0.006	0.71	0.89
Maine	-0.001	0.001	-0.001	0.001	0.52	0.74
Maryland	-0.053	0.095	-0.025	0.051	0.47	0.54
Massachusetts	-0.012	0.020	-0.005	0.010	0.41	0.50
Michigan	-0.107	0.056	-0.066	0.040	0.62	0.72
Minnesota	-0.016	0.016	-0.013	0.010	0.80	0.63
Mississippi	-0.011	0.004	-0.007	0.005	0.66	1.24
Missouri	-0.028	0.036	-0.020	0.028	0.70	0.78
Montana	-0.007	0.008	-0.006	0.007	0.92	0.90
Nebraska	-0.006	0.009	-0.004	0.007	0.61	0.78
Nevada	-0.001	0.001	-0.001	0.001	0.72	0.86
New Hampshire	-0.002	0.008	0.000	0.006	0.03	0.80
New Jersey	-0.322	0.718	0.060	0.305	-0.18	0.43
New Mexico	-0.003	0.002	-0.002	0.002	0.75	0.87
New York	-0.794	0.933	-0.086	0.179	0.11	0.19
North Carolina	-0.042	0.052	-0.029	0.050	0.69	0.96
North Dakota	-0.006	0.007	-0.004	0.005	0.66	0.71
Ohio	-0.197	0.154	-0.124	0.114	0.63	0.74
Oklahoma	-0.013	0.012	-0.009	0.008	0.67	0.69
Oregon	-0.002	0.004	-0.001	0.003	0.75	0.79
Pennsylvania	-0.559	0.228	-0.378	0.076	0.68	0.33
Rhode Island	-0.002	0.004	-0.001	0.002	0.46	0.49
South Carolina	-0.016	0.019	-0.010	0.015	0.63	0.81
South Dakota	-0.002	0.006	-0.001	0.006	0.43	0.94
Tennessee	-0.022	0.026	-0.012	0.022	0.53	0.86
Texas	-0.034	0.043	-0.021	0.040	0.62	0.93
Utah	-0.003	0.006	-0.002	0.005	0.70	0.79
Vermont	0.000	0.003	0.000	0.003	-2.37	0.80
Virginia	-0.078	0.100	-0.039	0.063	0.50	0.64
Washington	-0.002	0.006	-0.001	0.005	0.50	0.94
West Virginia	-0.132	0.135	-0.098	0.110	0.75	0.81
Wisconsin	-0.013	0.017	-0.008	0.011	0.57	0.68
Wyoming	-0.010	0.003	-0.008	0.002	0.79	0.85
Tribal Data	0.000	0.000	0.000	0.000	1.01	-10.30

Next, the estimate of the state and monitor specific ozone responses under the 2026 30% NO_X reduction case (or the 2023 base case) was used to calibrate the ozone AQAT to CAMx and to derive the calibration factors. One set of factors was created using the 2026 30% NO_X reduction case and is applied to all scenarios where EGU and/or non-EGUs were reduced, the other set of factors was created using the 2023 base and is applied to estimate base case ozone contributions in other alternative years (as well as for a sensitivity study). First, the changes in ozone predicted by the ozone AQAT and CAMx for the average design values were calculated for each state and each monitor for the 2026 30% NO_X reduction case or the 2023 base case air quality contributions relative to the 2026 base case concentrations. The change in modeled ozone (i.e., the difference between the 2023 and 2026 base case state-specifc contributions) was then divided by the change in ozone predicted by the uncalibrated AQAT, resulting in state and monitor-specific calibration factors (see Table C-2 for an example calculation using the two cases for the Westport CT monitor 090019003 in Fairfield County). The calculation of these state and monitor-specific calibration factors provided EPA with the ability to align the ozone response predicted by the ozone AQAT to the ozone response predicted by CAMx for EGUs and non-EGUs (based on the factors for the 30% reduction scenario) and to translate the base to alternative years (based on the factors for the 2023 base case scenario)[47].

The ozone AQAT calibration factors for all monitors can be found in the "Ozone_AQAT_Proposal.xlsx" excel workbook in columns I through BF, on worksheets "2026to2026w30_calib_(rec, stat)" and "2026to2023_calib_(rec, state)" for the two cases. The calibration factor, multiplied by the fractional change in emissions (relative to the 2026) base and multiplied by the 2026 base air quality contribution, results in the fractional change in air quality contribution for any alternative scenario.

The final step in the creation of the calibration factors is to make an adjustment to all the other air quality source apportionment categories that are not being directly varied within the tool. This includes contributions from anthropogenic emission in Canada and Mexico, emissions from offshore drilling platforms and shipping, emissions from wild and prescribed fires, biogenic emissions, and boundary conditions which represent the net contribution from all sources outside the modeling domain. In previous versions of AQAT, these contributions were held fixed at the base case values. For this proposed rule, because we have full source apportionment estimates for both calibration cases, we are able to adjust these contributions. We do this based on multiplying the change in the total anthropogenic contribution between the scenario and the base case by the ratio of the change from the sum of all other contributions divided by the change in the total anthropogenic contribution. For example, for the Westport CT receptor the difference between the 2026 and the 2026 30% reduction case was 0.24275 ppb for the all other contributions and -1.14287 ppb for the anthropogenic contributions, resulting in a ratio of -0.2124. In the 2026 engineering base, the total anthropogenic total was 45.4428 (compared to a 2026 modeled base value of 45.15215 ppb). The difference between these values was multiplied by the ratio to get a calibrated change in the "all other" contributions of -0.0617 ppb. Thus, the "all other" contribution changed from 29.44759 ppb to 29.3859 ppb.

Noting that EPA did not use these calibration factors since EPA only evaluated 2023 and 2026.

(2) Create a calibrated version of the ozone AQAT for emission control stringency level and associated emissions budget analysis for the proposed rule

Next, EPA examined the changes in the 2026 air quality contributions from changes in EGU and non-EGU emissions for various scenarios relative to the 2026 base case emissions (while using the calibration factors). This calibrated AQAT was used for each emission cost threshold level evaluated for EGUs and non-EGUs. For 2023 simulations, EPA started with the 2023 contributions and adjusted them using the 2026 calibration factors with the 30% NO_X reduction from EGUs and non-EGUs, the change in emissions relative to the 2026 base emissions which would be applied to the 2026 base case contributions.[48]

First, as described in sections A and B of this TSD for EGUs, EPA identified various cost threshold levels of emissions based on projected changes in emissions rates and adjusted historical data. For each state, for each year, the total anthropogenic NO_X emissions (excluding the EGU emissions) are presented in Table C-3.

The EGU point inventory is composed of emissions from units that report emissions to EPA's Clean Air Markets Division (CAMD) under 40 CFR Part 75 (most emissions from these sources are measured by CEMS) and units that are typically included in EPA's power sector modeling using the Integrated Planning Model (IPM) but that do not report to CAMD and typically lack CEMS (i.e., the nonCEM units). Within the air quality modeling platform, different approaches are taken depending on whether an emissions inventory for EGUs is created using an IPM-based emission estimates or an engineering analysis based platform. The nonCEM components for the 2016 base air quality model platform using EGU emissions based on CEMS, and the 2023 and 2026 air quality modeling cases based on IPM EGU emissions are shown in Table C-3. For each cost threshold engineering analysis based estimate examined in AQAT, a constant engineering-based nonCEM point EGU component was created from the 2016 air quality modeling platform and added to the engineering analysis cost threshold values. For scenarios where we would directly use IPM results, we would apply either the 2023 or 2026 nonCEM component from the air quality model platform. For 2023 and 2026, we show EGU emissions for units with CEMS as a function emissions control stringency level (see Tables B-1 through B-5 for the years 2023 through 2026, respectively). These levels include:

- Engineering Baseline,
- Optimize SCR,
- Optimize SCR + State-of-the-Art Combustion Controls (referred to as SOA CC),
- Optimize SNCR+ SCR ,
- Optimize SNCR+ SCR + SOA CC ,
- New SCR/SNCR + Optimize SNCR+ SCR + SOA CC.

In the construction of AQAT, for each scenario, we assembled an emission inventory from all anthropogenic sources for each state. In other words, we combine the year-specific

[48] For other years outside of 2023 and 2026, while not examined in this proposed rule, EPA would first use the 2026 base to 2023 base calibration factors to adjust to a different base year, then layer on additional adjustments using the 2026 based EGU and non-EGU AQAT changes as was done for 2023.

anthropogenic emissions from Table C-3, with the relevant EGU nonCEM component from C-3, and one of the EGU CEM estimates from Tables B-1 through B-5.

Finally, these emission totals are compared to the 2026 base case that was included in the air quality modeling. For each emission cost threshold level, EPA calculated the ratio of the emission differences from the scenario and the 2026 air quality modeling base case to the total NO_X emissions for the 2026 air quality modeling base case used in the air quality modeling for each state (see Tables C-4 and C-5). Scenarios that are not viable, for technical or policy reasons, have been grayed out in these tables.

In Tables C-3 and C-5, respectively, we examined the emission reduction for non-EGUs in Tier 1 and Tier 2, and then estimated the ratio of the emission difference relative to the 2026 air quality modeling base case.

For each scenario analyzed, on a receptor-by-receptor basis, the emissions change for each upwind state is associated with one of two emission levels (either the engineering base case emission level for that year or the particular cost threshold level) depending on whether the upwind state is "linked" to that receptor or if the receptor is located within the state. States that are contributing above the air quality threshold (i.e., greater than or equal to 1 percent of the NAAQS) to the monitor, as well as the state containing the monitor (regardless of whether that state linked to another monitor and regardless of whether it contributions equal to 1 percent of the NAAQS or not), make NO_X emission reductions available at the particular cost threshold level for that year. The emissions for all other states are adjusted to the engineering base case level for that year regardless of whether they are linked to another receptor.

For the control case scenarios, all states that were linked to any receptor in 2023 or in 2026 were simultaneously adjusted to the emission levels in the control case, regardless of whether (or not) the state was "linked" to a particular receptor. In these control scenarios, the state containing the monitor was only adjusted if it was linked to a monitor in another state. This scenario examines the emission results when budgets have been applied to the geography and can be used to show that emission reductions made for states that are not linked to a monitor are not anticipated to affect the air quality at that monitor to a degree that would change any results in the Step 3 analysis. For each monitor, the predicted change in contribution of ozone from each state is calculated by multiplying the state-specific 2026 base case ozone contributions from the air quality modeling by the state and receptor-specific calibration factor as well as by the ratio of the change in emissions (Tables C-4 or C-5 for either the emission cost threshold level or the engineering base case emission level depending on whether the state is linked in 2023 or 2026).[49] This calibrated change in ozone is then added to the ozone contribution from either the 2023 or 2026 base case air quality modeling, depending on whether the scenario is for 2023 or 2026. The result is the state and receptor specific "calibrated" total ozone contribution after implementation of the emission at a particular cost threshold level.

For each monitor, these state-level "calibrated" contributions are then summed to estimate total ozone contribution from the states to a particular receptor. Finally, "other" ozone contributions, as described in section C.2.(b), above are added to the state contributions to account for other sources of ozone affecting the receptor. The change in the "other" ozone concentrations are estimated by multiplying the change in the anthropogenic total between the scenario and the base case by the "nonState" calibration factors (calculated as the ratio of the

[49] The change in concentration can be positive or negative, depending on whether the state's total anthropogenic ozone season NO_X emissions for the scenario are larger or smaller than the air quality modeling base case emission level for that year.

change from these all other contributions divided by the change in the total anthropogenic contribution from the 2026 base case to the 2026 30% reduction case).[50] This change in the "other" contribution is then added to the base case value to get the total "other" contribution for the scenario. The total ozone from all the states and "other" contributions equals the average design values estimated in the assessment tool. The maximum design values were estimated by multiplying the estimated average design values by the ratio of the modeled 2026 base case maximum to average design values.

Generally, as the emission cost threshold stringency increased, the estimated average and maximum design values at each receptor decreased. In the assessment tool, the estimated value of the average design value was used to estimate whether the location will be out of attainment, while the estimated maximum design value was used to estimate whether the location will have problems maintaining the NAAQS. The area was noted as having a nonattainment or maintenance issue if either estimated air quality level was greater than or equal to 71 ppb.

[50] See column CB in "Scenario_2023" or "Scenario_2026" in the Ozone AQAT Proposed Rule Excel file

Table C-3. Ozone Season Anthropogenic NO_X Emissions (Tons) without EGUs for Each State for 2023 and 2026, the nonCEM EGU Emissions from 2016, 2023, and 2026, and non-EGU Tier 1 and Tier 2 Emissions (tons).

State	2023	2026	2016 nonCEM EGU Emissions (tons)	2023 IPM nonCEM EGU Emissions (tons)	2026 IPM nonCEM EGU Emissions (tons)	non-EGU Tier 1 (tons)	non-EGU Tier 1+Tier 2 (tons)
Alabama	60,935	55,559	482	447	454	-	-
Arizona	37,335	32,124	367	712	771	1,158	1,158
Arkansas	37,177	33,905	141	744	764	922	1,654
California	133,627	127,011	2,059	5,425	5,989	1,598	1,666
Colorado	47,331	43,944	334	1,883	1,919	605	605
Connecticut	10,117	9,215	1,272	1,542	1,529	-	-
Delaware	6,696	6,243	80	108	128	-	-
District of Columbia	1,372	1,283	0	18	18	-	-
Florida	88,929	80,635	5,810	6,964	7,007	-	-
Georgia	63,965	57,183	1,620	779	860	-	-
Idaho	19,258	16,946	528	118	118	-	-
Illinois	89,028	82,830	55	2,505	2,614	2,452	2,452
Indiana	62,476	57,227	611	1,234	1,061	2,787	3,175
Iowa	37,064	33,062	635	833	879	-	-
Kansas	59,950	55,935	109	706	1,162	-	-
Kentucky	42,436	38,993	1	437	495	2,291	2,291
Louisiana	93,619	89,483	3,885	2,943	3,056	4,121	6,769
Maine	12,706	11,693	1,972	1,167	1,131	-	-
Maryland	24,204	22,185	901	1,287	1,400	45	45
Massachusetts	25,975	24,237	2,566	1,960	1,963	-	-
Michigan	68,824	64,256	1,367	4,044	4,262	2,731	2,731
Minnesota	56,445	51,785	1,740	1,821	1,822	673	673
Mississippi	31,505	29,533	1,726	830	833	1,577	1,761
Missouri	64,300	57,595	471	355	481	3,103	3,103
Montana	24,522	21,735	933	105	115	-	-
Nebraska	33,201	29,654	665	549	547	-	-
Nevada	16,753	14,604	155	1,222	1,209	-	-
New Hampshire	7,041	6,496	374	236	222	-	-
New Jersey	32,531	29,836	1,083	1,667	1,572	-	-
New Mexico	64,011	60,945	98	201	211	-	-
New York	63,577	59,403	1,996	4,297	4,348	389	500
North Carolina	49,950	44,822	740	1,837	1,863	-	-
North Dakota	50,581	47,243	156	296	309	-	-
Ohio	75,112	69,485	722	1,029	1,134	2,611	2,790
Oklahoma	87,314	81,005	1	791	834	3,575	3,575
Oregon	31,977	28,226	712	1,174	1,115	-	-
Pennsylvania	96,364	91,144	2,187	5,188	6,484	3,132	3,284
Rhode Island	4,324	3,954	35	212	210	-	-
South Carolina	39,072	35,678	604	961	914	-	-
South Dakota	12,519	10,606	30	46	68	-	-
Tennessee	51,273	46,686	7	441	516	-	-
Texas	279,623	264,173	1,996	5,603	5,385	4,440	4,440
Utah	28,574	26,189	561	604	679	757	757
Vermont	3,807	3,376	61	46	2	-	-
Virginia	47,506	42,891	2,995	2,196	2,371	1,465	1,563
Washington	52,406	46,560	1,536	1,006	1,193	-	-
West Virginia	32,640	32,020	1	591	524	982	982
Wisconsin	42,620	38,936	61	723	712	677	2,150
Wyoming	29,310	27,910	11	904	81	826	826
Tribal Data	2,728	2,730	50	0	0	-	-

Table C-4. 2023 Fractional Difference in Emissions Relative to 2026 Air Quality Modeling Base Case for Each State.

State	Engineering Baseline	Optimize SCR	~~Optimize SCR + SOA CC~~	Optimize SNCR+ SCR	~~Optimize SNCR+ SCR + SOA CC~~	~~New SCR/SNCR + Optimize SNCR+ SCR + SOA CC~~
Alabama	0.03	0.02	0.02	0.02	0.02	0.01
Arizona	0.20	0.20	0.20	0.20	0.19	0.08
Arkansas	0.08	0.08	0.08	0.08	0.08	-0.05
California	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Colorado	0.02	0.02	0.02	0.02	0.02	-0.04
Connecticut	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Delaware	0.05	0.04	0.04	0.04	0.04	0.04
District of Columbia	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Florida	0.07	0.05	0.05	0.05	0.05	0.03
Georgia	0.06	0.06	0.06	0.06	0.06	0.06
Idaho	0.02	0.02	0.02	0.02	0.02	0.02
Illinois	0.00	0.00	0.00	-0.01	-0.01	-0.02
Indiana	0.03	0.02	0.02	0.02	0.02	0.00
Iowa	-0.01	-0.01	-0.01	-0.01	-0.01	-0.14
Kansas	0.06	0.05	0.05	0.05	0.05	0.01
Kentucky	0.04	-0.01	-0.02	-0.01	-0.02	-0.09
Louisiana	0.09	0.04	0.04	0.04	0.04	-0.02
Maine	0.05	0.05	0.05	0.05	0.05	0.05
Maryland	0.03	0.02	0.02	0.02	0.02	0.02
Massachusetts	0.03	0.03	0.03	0.03	0.03	0.03
Michigan	-0.01	0.00	0.00	0.00	0.00	-0.05
Minnesota	-0.01	-0.01	-0.01	-0.01	-0.01	-0.03
Mississippi	0.12	0.12	0.10	0.12	0.10	0.02
Missouri	0.13	0.00	0.00	0.00	0.00	-0.05
Montana	0.00	0.00	0.00	0.00	0.00	-0.07
Nebraska	-0.03	-0.03	-0.04	-0.03	-0.04	-0.18
Nevada	0.06	0.06	0.06	0.06	0.06	-0.02
New Hampshire	0.06	0.05	0.05	0.05	0.05	0.05
New Jersey	0.01	0.01	0.01	0.01	0.01	0.01
New Mexico	0.00	0.00	0.00	0.00	0.00	-0.01
New York	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02
North Carolina	0.08	0.02	0.02	0.02	0.02	-0.03
North Dakota	0.02	0.02	0.02	0.01	0.01	-0.12
Ohio	0.00	-0.02	-0.02	-0.02	-0.02	-0.02
Oklahoma	0.09	0.09	0.08	0.09	0.08	0.02
Oregon	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Pennsylvania	0.00	0.00	0.00	0.00	0.00	-0.01
Rhode Island	0.02	-0.01	-0.01	-0.01	-0.01	-0.01
South Carolina	0.01	-0.01	-0.01	-0.01	-0.01	-0.01
South Dakota	0.01	0.01	0.01	0.01	0.01	0.01
Tennessee	0.07	0.07	0.07	0.07	0.07	0.07
Texas	0.07	0.06	0.06	0.06	0.06	0.00
Utah	0.24	0.22	0.22	0.22	0.22	-0.12
Vermont	0.02	0.02	0.02	0.02	0.02	0.02
Virginia	0.08	0.07	0.07	0.07	0.06	0.06
Washington	0.05	0.05	0.05	0.05	0.05	0.02
West Virginia	0.04	0.07	0.06	0.07	0.05	-0.01
Wisconsin	0.08	0.08	0.08	0.08	0.08	0.06
Wyoming	0.16	0.13	0.11	0.13	0.11	-0.01
Tribal Data	0.44	0.42	0.42	0.42	0.42	0.08

Note: Scenarios that are not viable have had column heads struck through and associated data has been grayed out and

Table C-5. 2026 Fractional Difference in Emissions Relative to 2026 Air Quality Modeling Base Case for Each State.

State	Engineering Baseline	Optimize SCR	Optimize SCR + SOA CC	Optimize SNCR+ SCR	Optimize SNCR+ SCR + SOA CC	New SCR/SNCR + Optimize SNCR+ SCR + SOA CC	non-EGU Tier 1 +New SCR/SNCR + Optimize SNCR+ SCR + SOA CC	non-EGU Tier 1 +Tier 2 +New SCR/SNCR + Optimize SNCR+ SCR + SOA CC
Alabama	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Arizona	0.13	0.12	0.12	0.12	0.12	0.06	0.03	0.03
Arkansas	0.09	0.09	0.09	0.09	0.09	-0.04	-0.06	-0.08
California	-0.02	-0.03	-0.03	-0.03	-0.03	-0.03	-0.04	-0.04
Colorado	0.01	0.01	0.01	0.01	0.01	-0.04	-0.05	-0.05
Connecticut	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delaware	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
District of Columbia	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Florida	0.06	0.04	0.04	0.04	0.04	0.02	0.02	0.02
Georgia	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06
Idaho	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Illinois	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.05	-0.05
Indiana	-0.01	-0.02	-0.02	-0.02	-0.02	-0.03	-0.07	-0.08
Iowa	0.04	0.04	0.04	0.04	0.04	-0.09	-0.09	-0.09
Kansas	0.05	0.04	0.04	0.04	0.04	0.01	0.01	0.01
Kentucky	0.04	-0.02	-0.03	-0.02	-0.03	-0.09	-0.13	-0.13
Louisiana	0.08	0.02	0.02	0.02	0.02	-0.03	-0.07	-0.10
Maine	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Maryland	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Massachusetts	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Michigan	-0.01	0.00	0.00	0.00	0.00	-0.04	-0.08	-0.08
Minnesota	0.03	0.03	0.03	0.03	0.03	0.00	-0.01	-0.01
Mississippi	0.10	0.09	0.08	0.09	0.08	0.00	-0.05	-0.05
Missouri	0.16	0.03	0.03	0.03	0.03	-0.02	-0.07	-0.07
Montana	0.00	0.00	0.00	0.00	0.00	-0.07	-0.07	-0.07
Nebraska	0.01	0.01	0.00	0.01	0.00	-0.13	-0.13	-0.13
Nevada	0.06	0.06	0.06	0.06	0.06	-0.01	-0.01	-0.01
New Hampshire	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05
New Jersey	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
New Mexico	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
New York	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02
North Carolina	0.11	0.05	0.05	0.05	0.05	0.00	0.00	0.00
North Dakota	0.03	0.03	0.03	0.02	0.02	-0.11	-0.11	-0.11
Ohio	0.02	0.00	0.00	0.00	0.00	0.00	-0.03	-0.04
Oklahoma	0.10	0.09	0.09	0.09	0.09	0.02	-0.02	-0.02
Oregon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pennsylvania	-0.02	-0.02	-0.02	-0.02	-0.02	-0.03	-0.06	-0.06
Rhode Island	0.02	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
South Carolina	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02
South Dakota	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Tennessee	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Texas	0.09	0.08	0.08	0.08	0.08	0.03	0.01	0.01
Utah	0.16	0.15	0.15	0.15	0.15	-0.03	-0.05	-0.05
Vermont	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Virginia	0.07	0.05	0.05	0.05	0.05	0.04	0.01	0.01
Washington	0.05	0.04	0.04	0.04	0.04	0.02	0.02	0.02
West Virginia	0.14	0.17	0.15	0.16	0.15	0.08	0.06	0.06
Wisconsin	0.04	0.04	0.04	0.04	0.04	0.04	0.02	-0.02
Wyoming	0.16	0.13	0.11	0.13	0.11	-0.02	-0.04	-0.04
Tribal Data	0.44	0.43	0.43	0.43	0.43	0.08	0.08	0.08

3. Description of the analytic results.

For each year 2023 and 2026, EPA used the ozone AQAT to estimate improvements in downwind air quality at base case levels and at each of the cost threshold levels. At each cost threshold level, using AQAT, for each receptor, EPA examined the average and maximum design values for each of the receptors. EPA evaluated the degree of change in ozone concentration and assessed whether it decreased the average or maximum design values to below 71 ppb (at which point their nonattainment and maintenance issues, respectively, would be considered resolved). EPA also examined each state's air quality contributions at each emission level, assessing whether a state maintained at least one linkage (i.e., greater than or equal to 1% (0.70 ppb) to a receptor that was estimated to remain in nonattainment and/or maintenance. EPA examined the engineering base case, $1,600/ton, $1,800/ton, $11,000/ton and non-EGU Tier 1 and Tier 1+Tier 2 scenarios. Some of the EGU scenarios include emissions with and without installation of state of the art combustion controls. EPA assessed changes in air quality for the Tier 1 and Tier 2 non-EGU scenarios for 2026. In these cases, we included EGU emission reductions at the $11,000/ton cost threshold level when SCRs were installed. The preamble explains how EPA considered the results of the air quality analyses described in this TSD to determine the appropriate emission levels for eliminating significant contribution to nonattainment and interference with maintenance.

For each year, the average and maximum design values (in ppb) estimated using the assessment tool for each identified receptor for each cost threshold level have been rounded to hundredths of a ppb and can be found in Tables C-6 through C-9. There are 29 receptors in 2023 and 22 receptors in 2026. Scenarios that are not viable have been grayed out in these tables.

In 2023, we observe that the Clark County Nevada, monitor 320030075, switches from maintenance to attainment when existing SCRs are optimized. In other words, its maximum design value drops below 71 ppb (Table C-7). All other monitors consistently have their average and/or maximum design values at or above 71 ppb for all viable scenarios.

In 2026, of the 22 receptors, three receptors have their maximum design values drop below 71 ppb. The maximum design value for monitor 80350004 in Douglas County Colorado drops below 71 ppb when EGU emission reductions associated with new SCR are applied (inclusive of comparable reductions in Colorado, which is not linked to a receptor in another state). The maximum design values for receptors 480391004 in Brazoria County Texas and receptor 550590025 in Kenosha County Wisconsin have their maximum design values drop below 71 ppb when EGU SCRs and non-EGU Tier 1 emission reductions are applied. See Table C-9 for the values.

In the assessment of air quality using the calibrated assessment tool, we are able to estimate the change in the air quality contributions of each upwind state to each receptor (see the description of the state and receptor-specific contributions in section C.2.c.(2)) in order to determine whether any state's contribution is below the 1 percent threshold used in step 2 of the 4-Step Good Neighbor Framework to identify "linked" upwind states. For this assessment, we compared each state's adjusted ozone concentration against the 1% air quality threshold at each of the cost threshold levels at each remaining receptor, using AQAT. For 2023 and 2026, these results are shown in Tables C-10 and C-11, respectively.

To see static air quality contributions and design value estimates for the receptors of interest for each of the years for each of the cost levels, see the individual worksheets (labeled in Appendix B). For interactive worksheets, refer to the "202X_scenario" worksheets after setting the desired scenario in the "summary_DVs_202X" worksheet. In the summary_DVs worksheet, adjust cells I1 and I2 to match the desired scenario of interest. The numbering for the various scenarios is shown in Table C-12. For a cost threshold run, cell I1 would be a value of 0 through 10 (note that 6, 7, and 8 are invalid), while cell I2 should be fixed with a value of 0. Also included in Table C-12 is a list of the three scenarios used in the RIA. For these scenarios, cell I2 should be set as the same number as cell I1. The numbers are 17, 18, or 19 for the proposed rule, less stringent, or more stringent cases, respectively. Consequently, for each monitor, the linked, home, and nonlinked states are simulated using the same emission value that represents the base or policy case for that particular state.

For all linked states, in all years, across all cost threshold levels, we did not see any instances where all of the state's contributions dropped below 1% of the NAAQS assessed across all its linkages to remaining downwind receptors. That is, for a single receptor, if a state was linked to that receptor in the base case for that year the state almost always remained linked with a contribution greater than or equal to 1% of the NAAQS at all cost threshold levels. This is not a surprising result because, for a linkage to be resolved by emission reductions of just a few percent, the original base contribution would need to be within a few percent of the threshold. As a hypothetical example, if the state is making a 6% emission reduction in its overall anthropogenic ozone season NO_X emissions, and the calibration factor was 0.5, its original base case maximum contribution to a remaining unresolved nonattainment and/or maintenance receptor would need to be just under 1.03% of the NAAQS or 0.72 ppb, to drop below the 0.70 ppb linkage threshold. In some cases, for individual linkages, a state does drop below the threshold. However, while in these limited cases, an individual linkage to a particular receptor is resolved, we did not see any instances where all of the linkages across all of the remaining receptors drop below the linkage threshold. For a few states in 2026, namely Tennessee, Alabama, and Delaware the receptors to which they were linked in 2023 have their design values fall below the NAAQS, resulting in these state's maximum remaining air quality contribution to remaining receptors being below 1% of the NAAQS (Table C-11).

Lastly, as an alternative assessment, it was possible to estimate air quality concentrations in the "control scenario" at each downwind receptor using the ozone AQAT. Here, we apply a scenario where all states (regardless of whether they are linked to a particular receptor or to a different receptor in the geography) have the same cost threshold applied as do the "linked" states. And, for these cases, we kept the states containing the receptor (such as Colorado and Connecticut) that are not linked to receptors in other states at base case emission levels (rather than modulate them up to the same threshold as the linked upwind states). This allows us to assess whether impacts from states that are not specifically linked to a receptor would result in potential overcontrol. It also allows us to assess whether the assumption that a receptor state makes "fair share" emission reductions generates any instances of apparent "overcontrol" that is not actually certain to occur. In general, the differences are relatively small (though, for the receptors in Colorado to which Wyoming is linked), this difference is larger and it affects whether or not the receptor has its maximum design value drop below 71 ppb. The average and maximum design values for 2026 are shown in Tables C-13 and C-14.

Table C-6. 2023 Average Ozone DVs (ppb) for NO_X Emissions Cost Threshold Levels ($/ton) Assessed Using the Ozone AQAT for All Receptors.

site	state	county	Engineering Analysis Base	SCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + Generation Shifting~~	SCR Optimize + SNCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting~~	~~SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting~~
40278011	Arizona	Yuma	70.53	70.53	70.53	70.53	70.53	70.50
80350004	Colorado	Douglas	72.35	72.29	72.28	72.29	72.28	71.38
80590006	Colorado	Jefferson	73.23	73.19	73.19	73.19	73.19	72.30
80590011	Colorado	Jefferson	74.41	74.38	74.38	74.38	74.38	73.51
90010017	Connecticut	Fairfield	73.11	73.14	73.14	73.14	73.14	73.04
90013007	Connecticut	Fairfield	74.45	74.47	74.45	74.45	74.44	74.21
90019003	Connecticut	Fairfield	76.30	76.32	76.30	76.31	76.29	76.11
90099002	Connecticut	New Haven	72.11	72.11	72.08	72.09	72.07	71.85
170310001	Illinois	Cook	70.02	70.01	70.01	70.02	70.02	69.85
170310032	Illinois	Cook	70.14	70.15	70.15	70.16	70.15	70.03
170310076	Illinois	Cook	69.64	69.64	69.64	69.65	69.65	69.52
170314201	Illinois	Cook	70.19	70.18	70.18	70.18	70.18	70.05
170317002	Illinois	Cook	70.42	70.34	70.34	70.33	70.33	70.18
320030075	Nevada	Clark	70.09	70.06	70.06	70.06	70.06	69.93
420170012	Pennsylvania	Bucks	71.09	71.07	71.04	71.05	71.03	70.80
480391004	Texas	Brazoria	71.71	71.31	71.30	71.30	71.29	70.04
481210034	Texas	Denton	71.20	71.06	71.04	71.05	71.03	70.50
482010024	Texas	Harris	76.92	76.57	76.57	76.55	76.55	75.30
482010055	Texas	Harris	72.50	72.17	72.15	72.16	72.14	71.00
482011034	Texas	Harris	72.07	71.69	71.69	71.67	71.67	70.28
482011035	Texas	Harris	69.69	69.32	69.32	69.31	69.31	67.98
490110004	Utah	Davis	73.65	73.59	73.59	73.59	73.59	72.58
490353006	Utah	Salt Lake	74.35	74.29	74.29	74.29	74.29	73.27
490353013	Utah	Salt Lake	75.27	75.21	75.21	75.21	75.21	74.04
490570002	Utah	Weber	71.35	71.29	71.29	71.29	71.29	70.29
490571003	Utah	Weber	71.24	71.19	71.19	71.19	71.19	70.19
550590019	Wisconsin	Kenosha	73.17	73.07	73.07	73.07	73.07	72.90
550590025	Wisconsin	Kenosha	69.62	69.47	69.47	69.46	69.46	69.28
551010020	Wisconsin	Racine	71.70	71.61	71.61	71.61	71.61	71.44

Note: Scenarios that are not <u>viable</u> have had column heads struck through and associated data has been grayed out and

Table C-7. 2023 Maximum Ozone DVs (ppb) for NO_X Emissions Cost Threshold Levels ($/ton) Assessed Using the Ozone AQAT for All Receptors.

Site	state	county	Engineering Analysis Base	SCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + Generation Shifting~~	SCR Optimize + SNCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting~~	~~SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting~~
40278011	Arizona	Yuma	72.25	72.24	72.24	72.24	72.24	72.21
80350004	Colorado	Douglas	72.96	72.91	72.89	72.91	72.89	71.98
80590006	Colorado	Jefferson	73.84	73.80	73.80	73.80	73.80	72.91
80590011	Colorado	Jefferson	75.13	75.09	75.09	75.09	75.09	74.21
90010017	Connecticut	Fairfield	73.82	73.86	73.86	73.85	73.85	73.75
90013007	Connecticut	Fairfield	75.37	75.39	75.37	75.37	75.36	75.13
90019003	Connecticut	Fairfield	76.51	76.52	76.51	76.51	76.50	76.32
90099002	Connecticut	New Haven	74.16	74.15	74.13	74.14	74.12	73.89
170310001	Illinois	Cook	73.90	73.89	73.89	73.89	73.89	73.71
170310032	Illinois	Cook	72.78	72.79	72.79	72.80	72.79	72.67
170310076	Illinois	Cook	72.49	72.49	72.49	72.49	72.49	72.37
170314201	Illinois	Cook	73.75	73.74	73.74	73.74	73.74	73.60
170317002	Illinois	Cook	73.37	73.29	73.29	73.29	73.29	73.12
320030075	Nevada	Clark	71.01	70.98	70.98	70.98	70.98	70.84
420170012	Pennsylvania	Bucks	72.63	72.61	72.58	72.59	72.57	72.33
480391004	Texas	Brazoria	73.89	73.48	73.47	73.47	73.45	72.17
481210034	Texas	Denton	73.06	72.91	72.89	72.90	72.89	72.34
482010024	Texas	Harris	78.48	78.12	78.12	78.10	78.10	76.82
482010055	Texas	Harris	73.54	73.20	73.19	73.19	73.17	72.02
482011034	Texas	Harris	73.32	72.93	72.93	72.91	72.91	71.49
482011035	Texas	Harris	73.32	72.93	72.93	72.92	72.92	71.52
490110004	Utah	Davis	75.91	75.85	75.85	75.85	75.85	74.80
490353006	Utah	Salt Lake	75.99	75.93	75.93	75.93	75.93	74.89
490353013	Utah	Salt Lake	75.78	75.72	75.72	75.72	75.72	74.55
490570002	Utah	Weber	73.29	73.23	73.23	73.23	73.23	72.20
490571003	Utah	Weber	72.16	72.11	72.11	72.11	72.11	71.10
550590019	Wisconsin	Kenosha	74.09	73.99	73.99	73.99	73.99	73.81
550590025	Wisconsin	Kenosha	72.69	72.53	72.53	72.52	72.52	72.34
551010020	Wisconsin	Racine	73.64	73.55	73.55	73.55	73.55	73.37

Note: Scenarios that are not viable have had column heads struck through and associated data has been grayed out and

Table C-8. 2026 Average Ozone DVs (ppb) for NO_X Emissions Cost Threshold Levels ($/ton) Assessed Using the Ozone AQAT for All Receptors.

Site	State	County	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	70.11	70.10	70.10	70.10	70.10	70.09	70.06	70.06
80350004	Colorado	Douglas	70.94	70.89	70.88	70.89	70.88	70.23	70.07	70.07
80590006	Colorado	Jefferson	72.09	72.05	72.05	72.05	72.05	71.42	71.26	71.26
80590011	Colorado	Jefferson	72.97	72.94	72.94	72.94	72.94	72.32	72.16	72.16
90010017	Connecticut	Fairfield	71.60	71.62	71.62	71.62	71.62	71.52	71.36	71.35
90013007	Connecticut	Fairfield	73.09	73.08	73.07	73.07	73.05	72.84	72.55	72.54
90019003	Connecticut	Fairfield	74.83	74.83	74.81	74.82	74.80	74.63	74.41	74.40
90099002	Connecticut	New Haven	70.77	70.75	70.73	70.74	70.72	70.51	70.23	70.22
170310001	Illinois	Cook	69.05	69.05	69.05	69.05	69.05	68.96	68.83	68.73
170310032	Illinois	Cook	69.37	69.38	69.37	69.39	69.38	69.32	69.27	69.20
170310076	Illinois	Cook	68.75	68.76	68.76	68.76	68.76	68.71	68.59	68.51
170314201	Illinois	Cook	69.10	69.09	69.09	69.09	69.09	69.02	68.89	68.83
170317002	Illinois	Cook	69.36	69.29	69.29	69.29	69.29	69.18	69.02	68.98
480391004	Texas	Brazoria	70.93	70.54	70.52	70.52	70.51	69.35	68.88	68.72
482010024	Texas	Harris	76.28	75.92	75.92	75.91	75.91	74.77	74.33	74.23
490110004	Utah	Davis	72.20	72.16	72.16	72.16	72.16	71.61	71.51	71.51
490353006	Utah	Salt Lake	73.00	72.96	72.96	72.96	72.96	72.40	72.30	72.30
490353013	Utah	Salt Lake	74.10	74.05	74.05	74.05	74.05	73.45	73.34	73.34
490570002	Utah	Weber	70.30	70.26	70.26	70.26	70.26	69.74	69.64	69.63
550590019	Wisconsin	Kenosha	72.01	71.92	71.92	71.92	71.92	71.80	71.62	71.57
550590025	Wisconsin	Kenosha	68.46	68.32	68.32	68.32	68.32	68.19	67.99	67.95
551010020	Wisconsin	Racine	70.52	70.44	70.44	70.44	70.44	70.33	70.17	70.12

Table C-9. 2026 Maximum Ozone DVs (ppb) for NO_X Emissions Cost Threshold Levels ($/ton) Assessed Using the Ozone AQAT for All Receptors.

Site	State	County	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	71.81	71.80	71.80	71.80	71.80	71.79	71.76	71.76
80350004	Colorado	Douglas	71.55	71.49	71.48	71.49	71.48	70.83	70.67	70.67
80590006	Colorado	Jefferson	72.69	72.66	72.66	72.66	72.66	72.02	71.86	71.86
80590011	Colorado	Jefferson	73.68	73.65	73.65	73.65	73.65	73.02	72.86	72.86
90010017	Connecticut	Fairfield	72.30	72.32	72.32	72.32	72.32	72.22	72.05	72.04
90013007	Connecticut	Fairfield	73.99	73.99	73.97	73.97	73.96	73.74	73.45	73.43
90019003	Connecticut	Fairfield	75.03	75.03	75.01	75.02	75.00	74.83	74.61	74.59
90099002	Connecticut	New Haven	72.78	72.76	72.74	72.75	72.73	72.51	72.23	72.21
170310001	Illinois	Cook	72.87	72.87	72.87	72.87	72.87	72.77	72.63	72.53
170310032	Illinois	Cook	71.98	71.99	71.99	72.00	71.99	71.93	71.87	71.80
170310076	Illinois	Cook	71.56	71.57	71.57	71.57	71.57	71.52	71.40	71.31
170314201	Illinois	Cook	72.61	72.60	72.60	72.60	72.60	72.53	72.39	72.32
170317002	Illinois	Cook	72.27	72.20	72.20	72.20	72.20	72.09	71.92	71.88
480391004	Texas	Brazoria	73.09	72.68	72.67	72.67	72.65	71.46	70.97	70.81
482010024	Texas	Harris	77.82	77.46	77.46	77.44	77.44	76.28	75.83	75.73
490110004	Utah	Davis	74.42	74.37	74.37	74.37	74.37	73.81	73.70	73.70
490353006	Utah	Salt Lake	74.61	74.57	74.57	74.57	74.57	74.00	73.90	73.90
490353013	Utah	Salt Lake	74.60	74.56	74.56	74.56	74.56	73.95	73.84	73.84
490570002	Utah	Weber	72.22	72.17	72.17	72.17	72.17	71.64	71.53	71.53
550590019	Wisconsin	Kenosha	72.91	72.83	72.83	72.83	72.83	72.70	72.52	72.47
550590025	Wisconsin	Kenosha	71.48	71.33	71.33	71.32	71.32	71.19	70.98	70.95
551010020	Wisconsin	Racine	72.42	72.35	72.35	72.35	72.35	72.24	72.07	72.02

Table C-10. 2023 Maximum Air Quality Contribution (ppb) to a Remaining Receptor.[51]

state	Engineering Analysis Base	SCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + Generation Shifting~~	SCR Optimize + SNCR Optimize + Generation Shifting	~~SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting~~	~~SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting~~
Alabama	0.91	0.90	0.90	0.90	0.90	0.90
Arizona	0.46	0.46	0.46	0.46	0.46	0.46
Arkansas	1.48	1.48	1.48	1.48	1.48	1.34
California	7.33	5.04	5.04	5.04	5.04	5.04
Colorado	0.21	0.21	0.21	0.21	0.21	0.21
Connecticut	0.21	0.21	0.21	0.21	0.21	0.21
Delaware	1.43	1.42	1.42	1.42	1.42	1.42
District of Columbia	0.08	0.08	0.08	0.08	0.08	0.08
Florida	0.18	0.18	0.18	0.18	0.18	0.18
Georgia	0.18	0.18	0.18	0.18	0.18	0.18
Idaho	0.59	0.59	0.59	0.59	0.59	0.59
Illinois	18.55	18.56	18.56	18.56	18.56	18.57
Indiana	7.20	7.18	7.18	7.18	7.18	7.09
Iowa	0.64	0.64	0.64	0.64	0.64	0.64
Kansas	0.62	0.62	0.62	0.62	0.62	0.62
Kentucky	0.91	0.88	0.87	0.88	0.87	0.82
Louisiana	7.51	7.23	7.23	7.22	7.22	6.95
Maine	0.02	0.02	0.02	0.02	0.02	0.02
Maryland	2.44	2.44	2.44	2.44	2.44	2.44
Massachusetts	0.31	0.31	0.31	0.31	0.31	0.31
Michigan	1.67	1.68	1.68	1.68	1.68	1.64
Minnesota	0.97	0.97	0.97	0.97	0.97	0.96
Mississippi	1.22	1.22	1.21	1.22	1.21	1.16
Missouri	1.81	1.67	1.67	1.67	1.67	1.61
Montana	0.12	0.12	0.12	0.12	0.12	0.12
Nebraska	0.36	0.36	0.36	0.36	0.36	0.36
Nevada	0.94	0.94	0.94	0.94	0.94	0.88
New Hampshire	0.10	0.10	0.10	0.10	0.10	0.10
New Jersey	8.84	8.85	8.85	8.85	8.85	8.85
New Mexico	0.30	0.31	0.30	0.30	0.30	0.30
New York	16.78	16.79	16.79	16.79	16.79	16.77
North Carolina	0.65	0.65	0.65	0.65	0.65	0.65
North Dakota	0.38	0.38	0.38	0.38	0.38	0.38
Ohio	1.95	1.93	1.93	1.93	1.93	1.93
Oklahoma	1.26	1.26	1.25	1.26	1.25	1.20
Oregon	1.10	1.10	1.10	1.10	1.10	1.10
Pennsylvania	6.90	6.93	6.93	6.92	6.92	6.85
Rhode Island	0.05	0.05	0.05	0.05	0.05	0.05
South Carolina	0.20	0.20	0.20	0.20	0.20	0.20
South Dakota	0.10	0.10	0.10	0.10	0.10	0.10
Tennessee	0.97	0.97	0.97	0.97	0.97	0.97
Texas	1.89	1.88	1.88	1.88	1.88	1.81
Utah	1.59	1.63	1.58	1.58	1.58	1.26
Vermont	0.03	0.03	0.03	0.03	0.03	0.03
Virginia	1.86	1.84	1.84	1.84	1.84	1.83
Washington	0.35	0.35	0.35	0.35	0.35	0.35
West Virginia	1.50	1.53	1.52	1.52	1.51	1.44
Wisconsin	2.75	2.75	2.75	2.75	2.75	2.72
Wyoming	0.93	0.91	0.90	0.91	0.90	0.81
Tribal Data	0.08	0.03	0.08	0.08	0.08	0.08

Note: Scenarios that are not viable have had column heads struck through and associated data has been grayed out and

[51] Values greater than or equal to 0.70 ppb indicate the state remains linked to a remaining downwind receptor.

Table C-11. 2026 Maximum Air Quality Contribution (ppb) to a Remaining Receptor.[52]

State	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + 2
Alabama	0.49	0.49	0.49	0.49	0.49	0.49	0.17	0.17
Arizona	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Arkansas	1.41	1.40	1.40	1.40	1.40	1.26	0.68	0.68
California	4.79	4.79	4.79	4.79	4.79	4.79	4.76	4.75
Colorado	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Connecticut	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Delaware	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
District of Columbia	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Florida	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Georgia	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.16
Idaho	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Illinois	18.15	18.15	18.15	18.16	18.16	18.17	17.83	17.83
Indiana	6.96	6.95	6.95	6.95	6.95	6.92	6.81	6.80
Iowa	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Kansas	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Kentucky	0.83	0.79	0.79	0.79	0.79	0.75	0.72	0.72
Louisiana	7.38	7.10	7.10	7.09	7.09	6.82	4.03	3.95
Maine	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Maryland	1.26	1.26	1.26	1.25	1.25	1.25	1.25	1.25
Massachusetts	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Michigan	1.58	1.59	1.59	1.59	1.59	1.55	1.52	1.52
Minnesota	0.93	0.93	0.93	0.93	0.93	0.91	0.91	0.91
Mississippi	0.97	0.97	0.95	0.97	0.95	0.90	0.40	0.40
Missouri	1.70	1.57	1.57	1.56	1.56	1.51	0.95	0.95
Montana	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Nebraska	0.23	0.23	0.23	0.23	0.23	0.21	0.21	0.21
Nevada	0.86	0.86	0.86	0.86	0.86	0.80	0.80	0.80
New Hampshire	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
New Jersey	8.53	8.54	8.54	8.54	8.54	8.54	8.54	8.54
New Mexico	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
New York	16.55	16.57	16.57	16.57	16.57	16.55	16.53	16.53
North Carolina	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
North Dakota	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Ohio	1.86	1.83	1.83	1.83	1.83	1.84	1.80	1.79
Oklahoma	0.77	0.77	0.77	0.77	0.77	0.74	0.71	0.71
Oregon	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Pennsylvania	6.75	6.76	6.76	6.75	6.75	6.68	6.54	6.53
Rhode Island	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
South Carolina	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
South Dakota	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Tennessee	0.36	0.36	0.36	0.36	0.36	0.36	0.26	0.26
Texas	1.81	1.80	1.80	1.80	1.80	1.73	1.62	1.62
Utah	1.34	1.33	1.33	1.33	1.33	0.94	0.92	0.92
Vermont	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Virginia	1.75	1.74	1.74	1.74	1.74	1.73	1.69	1.69
Washington	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
West Virginia	1.50	1.53	1.52	1.52	1.51	1.44	1.41	1.41
Wisconsin	2.51	2.51	2.51	2.51	2.51	2.50	2.47	2.41
Wyoming	0.91	0.89	0.88	0.89	0.88	0.52	0.52	0.52
Tribal Data	0.08	0.08	0.08	0.08	0.08	0.06	0.06	0.06

[52] Values greater than or equal to 0.70 ppb indicate the state remains linked to a remaining downwind receptor.

Table C-12. Description of the Various Scenarios Modeled in AQAT.

Scenario	Cost Threshold Level	Description
0	$0	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs
1	$1,600	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR optimize + Generation Shifting
2	$1,600	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR optimize + SOA CC + Generation Shifting
3	$1,800	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR/SNCR optimize + Generation Shifting
4	$1,800	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR/SNCR optimize + SOA CC + Generation Shifting
5	$11,000	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR/SNCR optimize + SOA CC + Generation Shifting + SCR Retrofit + Generation Shifting
9	$11,000 +_ non-EGU Tier 1	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR/SNCR optimize + SOA CC + Generation Shifting + SCR Retrofit + Generation Shifting + non-EGU Tier 1
10	11,000 +_ non-EGU Tier 1 + Tier 2	Baseline Engineering Analysis 202x OS NO_X + engineering nonCEMs +SCR/SNCR optimize + SOA CC + Generation Shifting + SCR Retrofit + Generation Shifting + non-EGU Tier 1 + non-EGU Tier 2
17	RIA Proposed Rule	EGU and non-EGU controls associated with the proposed rule in the RIA.
18	RIA Less Stringent	EGU and non-EGU controls associated with the less stringent case in the RIA.
19	RIA More Stringent	EGU and non-EGU controls associated with the more stringent case in the RIA.

Table C-13. 2026 Average Ozone DVs (ppb) for Each "Control Scenario" Assessed.

Site	State	County	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	70.11	70.10	70.10	70.10	70.10	70.09	70.07	70.07
80350004	Colorado	Douglas	70.94	70.90	70.88	70.90	70.88	70.56	70.49	70.49
80590006	Colorado	Jefferson	72.09	72.05	72.04	72.05	72.04	71.78	71.72	71.72
80590011	Colorado	Jefferson	72.97	72.94	72.93	72.94	72.93	72.67	72.62	72.62
90010017	Connecticut	Fairfield	71.60	71.58	71.57	71.58	71.57	71.37	71.14	71.12
90013007	Connecticut	Fairfield	73.09	73.04	73.02	73.03	73.01	72.72	72.39	72.37
90019003	Connecticut	Fairfield	74.83	74.79	74.78	74.78	74.77	74.54	74.28	74.26
90099002	Connecticut	New Haven	70.77	70.71	70.69	70.70	70.68	70.40	70.09	70.07
170310001	Illinois	Cook	69.05	69.01	69.00	69.01	69.00	68.83	68.65	68.54
170310032	Illinois	Cook	69.37	69.34	69.34	69.35	69.34	69.24	69.15	69.08
170310076	Illinois	Cook	68.75	68.73	68.72	68.73	68.73	68.59	68.42	68.33
170314201	Illinois	Cook	69.10	69.05	69.05	69.05	69.05	68.91	68.75	68.68
170317002	Illinois	Cook	69.36	69.28	69.27	69.28	69.27	69.09	68.88	68.84
480391004	Texas	Brazoria	70.93	70.51	70.49	70.49	70.48	69.29	68.79	68.63
482010024	Texas	Harris	76.28	75.90	75.89	75.89	75.87	74.58	74.09	73.97
490110004	Utah	Davis	72.20	72.15	72.15	72.15	72.15	71.60	71.50	71.50
490353006	Utah	Salt Lake	73.00	72.95	72.95	72.95	72.95	72.40	72.30	72.30
490353013	Utah	Salt Lake	74.10	74.05	74.05	74.05	74.05	73.40	73.30	73.30
490570002	Utah	Weber	70.30	70.26	70.25	70.26	70.25	69.69	69.58	69.58
550590019	Wisconsin	Kenosha	72.01	71.91	71.90	71.91	71.90	71.70	71.47	71.41
550590025	Wisconsin	Kenosha	68.46	68.30	68.29	68.29	68.28	68.06	67.81	67.76
551010020	Wisconsin	Racine	70.52	70.42	70.41	70.42	70.41	70.21	69.99	69.93

Table C-14. 2026 Maximum Ozone DVs (ppb) for Each "Control Scenario" Assessed.

Site	State	County	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	71.81	71.80	71.80	71.80	71.80	71.79	71.77	71.77
80350004	Colorado	Douglas	71.55	71.50	71.49	71.50	71.49	71.16	71.09	71.09
80590006	Colorado	Jefferson	72.69	72.66	72.65	72.66	72.65	72.38	72.32	72.32
80590011	Colorado	Jefferson	73.68	73.64	73.63	73.64	73.63	73.38	73.32	73.32
90010017	Connecticut	Fairfield	72.30	72.28	72.27	72.28	72.27	72.07	71.84	71.82
90013007	Connecticut	Fairfield	73.99	73.95	73.93	73.93	73.91	73.62	73.29	73.26
90019003	Connecticut	Fairfield	75.03	75.00	74.98	74.98	74.97	74.74	74.48	74.46
90099002	Connecticut	New Haven	72.78	72.72	72.70	72.71	72.69	72.40	72.09	72.06
170310001	Illinois	Cook	72.87	72.83	72.82	72.83	72.82	72.63	72.44	72.34
170310032	Illinois	Cook	71.98	71.95	71.95	71.96	71.95	71.84	71.75	71.68
170310076	Illinois	Cook	71.56	71.54	71.53	71.54	71.54	71.39	71.22	71.13
170314201	Illinois	Cook	72.61	72.56	72.56	72.56	72.56	72.42	72.24	72.17
170317002	Illinois	Cook	72.27	72.19	72.18	72.19	72.18	71.99	71.77	71.73
480391004	Texas	Brazoria	73.09	72.65	72.64	72.63	72.62	71.40	70.88	70.72
482010024	Texas	Harris	77.82	77.44	77.43	77.42	77.41	76.09	75.58	75.47
490110004	Utah	Davis	74.42	74.37	74.37	74.37	74.37	73.80	73.69	73.69
490353006	Utah	Salt Lake	74.61	74.56	74.56	74.56	74.56	74.00	73.89	73.89
490353013	Utah	Salt Lake	74.60	74.55	74.55	74.55	74.55	73.90	73.80	73.80
490570002	Utah	Weber	72.22	72.17	72.17	72.17	72.17	71.58	71.48	71.48
550590019	Wisconsin	Kenosha	72.91	72.81	72.81	72.81	72.80	72.60	72.37	72.31
550590025	Wisconsin	Kenosha	71.48	71.30	71.30	71.30	71.29	71.06	70.80	70.75
551010020	Wisconsin	Racine	72.42	72.33	72.32	72.32	72.32	72.11	71.88	71.82

4. Comparison between the air quality assessment tool estimates

As described earlier, AQAT was calibrated using modeled ozone data from a 2026 case where EGUs and non-EGUs were reduced by 30%. We also had a second set of calibration factors, based on the change from the 2026 base to the 2023 base (which could be used to modulate to alternative years, though these were not pursued). Thus, it was possible to evaluate the estimates from the tool for a comparable scenario using alternative calibration factors. The average design values from AQAT as well as the differences for the 2026 scenario with EGU SCR and non-EGU Tier 1 + Tier 2 are shown in Table C-15. The AQAT values and the differences in the table have been rounded to a hundredth of a ppb. For this set of scenarios, the differences are moderate, with a maximum value of 0.37 ppb. Since the calibration factor based on the 30% EGU and non-EGU emission reduction was developed based on modulating the sectors being regulated in this rulemaking, we conclude that these factors were the ones to use within the Step 3 methodology.

The results of this comparison, which are relatively similar, demonstrate that, considering the time and resource constraints faced by the EPA, the AQAT provides reasonable estimates of air quality concentrations for each receptor, and can provide reasonable inputs for the multi-factor assessment and overcontrol assessment.

Table C-15. 2026 Average Ozone DVs (ppb) for the EGU SCR and non-EGU Tier 1 and Tier 2 Scenarios Using Two Calibration Factors.

Site	State	County	EGU SCR and non-EGU Tier 1+Tier 2 (30% EGU and non-EGU Calibration)	EGU SCR and non-EGU Tier 1+Tier 2 (2023 Calibration)	Delta AQ between Calibration Approaches
40278011	Arizona	Yuma	70.06	70.02	0.04
80350004	Colorado	Douglas	70.07	69.89	0.18
80590006	Colorado	Jefferson	71.26	71.10	0.17
80590011	Colorado	Jefferson	72.16	71.90	0.26
90010017	Connecticut	Fairfield	71.35	71.37	-0.02
90013007	Connecticut	Fairfield	72.54	72.77	-0.24
90019003	Connecticut	Fairfield	74.40	74.54	-0.15
90099002	Connecticut	New Haven	70.22	70.38	-0.16
170310001	Illinois	Cook	68.73	68.50	0.23
170310032	Illinois	Cook	69.20	68.97	0.22
170310076	Illinois	Cook	68.51	68.14	0.37
170314201	Illinois	Cook	68.83	68.65	0.18
170317002	Illinois	Cook	68.98	68.76	0.22
480391004	Texas	Brazoria	68.72	69.01	-0.29
482010024	Texas	Harris	74.23	74.21	0.03
490110004	Utah	Davis	71.51	71.44	0.07
490353006	Utah	Salt Lake	72.30	72.24	0.06
490353013	Utah	Salt Lake	73.34	73.37	-0.03
490570002	Utah	Weber	69.63	69.46	0.18
550590019	Wisconsin	Kenosha	71.57	71.35	0.22
550590025	Wisconsin	Kenosha	67.95	67.71	0.24
551010020	Wisconsin	Racine	70.12	69.90	0.22

D. Selection of Short-term Rate Limits

For the reasons described in the preamble, EPA is proposing to complement the longer-term mass-based trading program (premised on seasonal emission rate performance) with a short-term emission rate limit for some units. EPA considered hourly, 24-hour, 7-day and 30-day limits as appropriate short-term rate limits. While all these time-periods would likely provide appropriate assurance for post-combustion controls to operate on an hourly and daily basis, including during ozone episodes, as described in the preamble, EPA identified the daily (e.g., 24-hr) limit as an appropriate time-period for the short-term rate limit.

As described in the preamble, in establishing the 24-hour emission limits, EPA evaluated several methods and data sets. These are:

1. EPA evaluated daily emission patterns for units that have SCRs with seasonal rates in the range of the average seasonal emission rates identified in the rulemaking (i.e., at 0.08 lb/MMBtu or below).
2. EPA applied the concept of "comparable stringency" developed in the 2014 1-hr SO2 attainment area guidance for converting emission rates so they provide comparable stringency over different time frames. In this case, we convert longer-term emission rate assumptions (e.g., seasonal and monthly rates at 0.08 lb/MMBtu to daily rates at 0.14 lb/MMBtu)

Each of these methods is discussed in more detail, below.

1. <u>Observations of fleet operation for well-controlled units</u>

EPA examined the daily operation of coal-fired units with SCR in 2021, comparing the daily rate to the seasonal average rate. We counted the number of days that had values higher than particular values (e.g., 0.12 lb/MMBtu, 0.14 lb/MMBtu, and 0.16 lb/MMBtu) as a function of the seasonal average emission rate. Knowing that there is variation in emission rate, with values above and below the seasonal average, we wanted to identify the frequency and magnitude of some of the higher emission rate values for units that typically had low seasonal rates. A low seasonal rate suggests that the post-combustion controls on the unit are well-designed and modern and are being well-run and well-maintained. The results are shown in Figure D-1. As an example, for a unit with a seasonal rate of 0.08, we could expect, on average, about 4.7% of the daily rate values to be higher than 0.14 lb/MMBtu.

Focusing on the 0.14 lb/MMBtu rate, EPA identified 164 units that had ozone season rates at or below 0.08 lb/MMBtu. As described above, daily emission rates from these units rarely exceeded 0.14 lb/MMBtu. On the days that the rate did exceed, it was frequently close to the 0.14 lb/MMBtu rate. Considering the number of tons emitted on days when the daily emission rates exceeded 0.14. There were a total of 572 tons of "excess" emissions (i.e., emissions above what would have been emitted had the emission rate been capped at 0.14 lb/MMBtu on those days). This compares with 60,339 tons of total seasonal emissions from those units. Thus, these "excess" emissions are about 0.9% of their seasonal emissions.

A

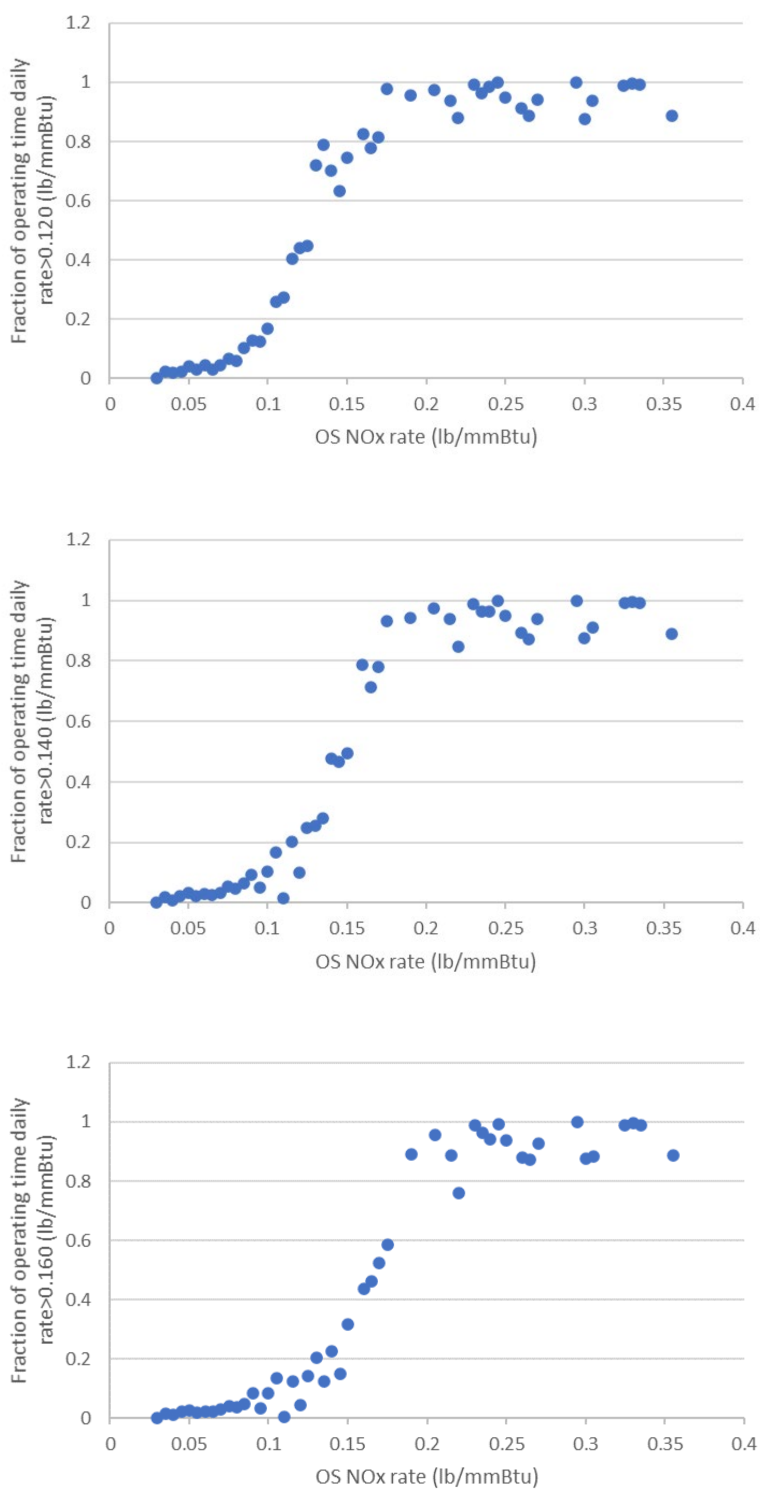

Figure D-1. Examination of the fraction of operating time where the daily rate was higher than 0.12, 0.14, or 0.16 lb/MMBtu in 2021 (in A, B, and C, respectively) as a function of the average ozone season emission rate for the unit.

2. <u>Creating "comparably stringent" emission rates using the 2014 1-hour SO2 concepts</u>

a. Background

In the 2014 Guidance for 1- Hour SO2 Nonattainment Area SIP Submissions, EPA introduced concepts and methods for ensuring that NAAQS violations of the 1-hr SO2 NAAQS do not occur.[53,54] For example, the 2014 1-hr SO2 Guidance defined a "critical emission value" to refer to the hourly emission rate that an air quality model predicts would result in the 5-year average of the annual 99th percentile of daily maximum hourly concentrations at the level of the 1-hour NAAQS, given representative meteorological data for the area. In the guidance EPA explained that, for that standard, establishing 1-hour limits at the critical emission value is a conservative approach to developing a control strategy that ensures that NAAQS violations do not occur. Consequently, the EPA recommended that approach in the September 2011 draft guidance, as it was consistent with the EPA's longstanding SO2 policy that source emission limits should match the averaging time of the relevant SO2 NAAQS.

The EPA continues to consider that approach to be acceptable. However, as discussed in the 2014 Guidance, after receiving numerous comments, and analyzing the impact of emissions variability on air quality, the EPA expects that it may also be possible in specific cases for states to develop control strategies that account for variability in l-hour emissions rates through emission limits with averaging times that are longer than 1 hour, using averaging times as long as 30-days, but still provide for attainment of the 2010 SO_2 NAAQS. The EPA would need to consider specific submitted candidate emission limits along with other elements of a submitted SIP attainment demonstration to conclude whether such a limit would be approvable. This view is based on the EPA's general expectation that, if periods of hourly emissions above the critical emission value are a rare occurrence at a source, particularly if the magnitude of the emissions is not substantially higher than the critical emissions value, these periods would be unlikely to have a significant impact on air quality, insofar as they would be very unlikely to occur repeatedly at the times when the meteorology is conducive for high ambient concentrations of SO2. The EPA believes that making this option available to states could reflect an appropriate balance between providing a strong assurance that the NAAQS will be attained and maintained, while still acknowledging the necessary variability in source operations and the impairment to source operations that would occur under what could be in some cases an unnecessarily restrictive approach to constraining that variability. Nevertheless, in order to provide adequate assurance that the NAAQS will be met, the EPA noted that any emissions limits based on averaging periods longer than 1 hour should be designed to have comparable stringency to a 1-hour average limit at the critical emission value. A limit based on the 30-day average of hourly emissions levels, for example, at a given numeric level is likely to be a less stringent limit than a 1-hour limit at the same numeric level 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. Therefore, as a general matter, the EPA expects that any emission rates with a longer averaging time would reflect a lower numeric emission rate and emission rates with shorter

[53] https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf

[54] We note that given the form of the emission rate metric, the emissions and operational data used in the calculation, as well as the NAAQS being addressed are important to consider when setting an emission rate and that procedures that may be applicable for one NAAQS (i.e., the 2015 8-hr Ozone) would not necessarily be applicable for another (e.g., 1-hour SO2).

averaging time would reflect a higher numeric emission rates. Although the emission rate values are different numerically, they are of comparable stringency when the averaging time is applied.

b. Application

In this rule, EPA is looking to ensure that emission reductions achieved are commensurate with the installation and operation of post-combustion control devices for portions of the fossil EGU fleet. Consistent with the 8 hour ozone NAAQS time frame, EPA is meeting its statutory obligation to eliminate significant contribution from upwind states, in part, by ensuring the operation of these post-combustion controls (or commensurate reductions) every day when the units are operating. To achieve this, EPA converts its seasonal emission rate performance assumptions for such post-combustion control technology (used to determine seasonal state mass limits) to a daily emission rate limit of comparable stringency. EPA does this by utilizing the concepts applied in the 2014 1-hour SO2 Guidance. That Guidance was developed for a similar purpose, to identify "comparably stringent" emissions limits over different time periods. EPA notes that concept could be applied to help identify daily (e.g., 24-hour) limits that are comparably stringent to longer-term limits. In other words, because these sources are only a portion of the problem causing NAAQS violations, and because EPA defines the emissions that are significantly contributing inclusive of emissions that are eliminated by installation and full operation of post-combustion control equipment at a portion of the EGU fleet, and we have clear definitions of longer-term (e.g., seasonal) emissions rates that eliminate significant contribution, we could use the 1-hr SO2 methodology to identify complementary short-term limits that are "comparably stringent" that would ensure control operation on a daily basis. In this case, we are not looking for 1-hr emission limits, nor are we looking to limit emissions on a pounds per hour basis to match a modeled "critical emissions value." Rather, we have seasonal emission rates of 0.08 lb/MMBtu (demonstrating full SCR operation for units with this existing technology) which can be converted to 24-hour limits in a pound per unit of heat input rather than a pound per hour framework. As with the 1-hr SO2 limit, we expect that the longer-term rates would be lower than 24-hour limits that would be adjusted higher to accommodate the variation in operation, demand for electricity, variation in fuel, and other technical and engineering limitations.

We expect that the use of shorter-term averages may be necessary in cases where sources' emission rates exhibit a high degree of variability with some time-periods with high emission rates (i.e., units that have post-combustion control equipment and units that need new post-combustion control equipment installed). Therefore, EPA is limiting its application of short-term limits to coal-fired units with SCR retrofit potential or that are already equipped with SCR. In such cases, as previously noted, the EPA believes this approach provides appropriate flexibility while still requiring approximately the same control strategy as demonstrated with longer-term emission rate averages (in particular, the averages used to enshrine emissions budgets).

The EPA issued the 2014 1-hr SO2 guidance based on consideration of the statistical nature of the NAAQS and based on analyses of selected cases suggesting that comparably stringent short term average limits can commonly be expected to provide adequate assurance of control operation.

Here, EPA expects that an emission limit established for a source with an averaging time shorter than 30-day or seasonal would be set at a higher level, yet would provide a comparable degree of stringency as the longer-term emission rate assumption (that would provide assurance that significant contribution and interference with maintenance are being eliminated). In theory, the longer-term emission rate assumptions would allow occasional emission spikes, but this longer-term emission rate (or comparable mass limit implemented in the trading program) would also require emissions to be lower for most of the averaging period than they would be required to be with a short-term emission limit (i.e., 24-hour). Here, the EPA envisions that meeting both the short-term rate limits and longer-term emission rate assumption in practice would require similar emission control levels and would commonly result in similar emission patterns, yet having the short-term backstop rate provides additional assurance that sources will reliably operate their SCRs each day throughout the ozone season.

In the 2014 1-hour SO2 guidance Appendix C presented example calculations in which the level of the longer-term emission rate is derived from a statistical analysis of a set of data that reflect the emissions variability that the controlled source is expected to exhibit. The analysis underlying those example calculations compared the set of emission values averaged over the longer averaging time against the set of 1-hour emission values from which the longer-term averages were derived[55]. The example calculations in Appendix C reflected a comparison of 99th percentile values of the sets of 30-day averages and 1-hour averages. Alternative averaging times were also explored, including 24-hr time-periods. In applying the 1-hour SO2 guidance concepts, here, we envision that the control strategy needed to meet a comparably stringent longer term emission rate would be essentially the same as the control strategy needed to meet a daily limit, specifically the operation of SCR post-combustion controls.

Emission limits are often expressed either in terms of emission rates (e.g., pounds per hour) or in terms of emission factors (e.g., lb/MMBtu heat input). The variability of values for these two parameters will likely be different. Therefore, analyses of a longer-term average emission rate that is comparably stringent to a shorter-term emission rate limit would need to be designed to assess variability for the parameter for which an emission limit is being set. Since we are focused here on ensuring installation and operation of control equipment, rather than constraining the operation of the unit through a mass limitation, we focused on variability in emissions rate (lb/MMBtu).

We acknowledge that supplemental limits on the frequency and/or magnitude of occasions of elevated emissions can be a valuable element of a plan that ensures control operation and protects against NAAQS violations may be useful in some instances. However, because of the differences between 1-hr SO2 and 8-hr Ozone (with the latter being created based on the emissions of NO_X and VOCs from hundreds or thousands of individual point sources, and millions of individual mobile sources, rather than a handful of large point sources), we find that a long-term emission rate assumption (expressed as a seasonal mass limit) coupled with a short-term daily emission limit applied to individual units incentivizes best performance of controls while also ensuring operation of the controls each day.

c. Methods and Results

Starting with the coal-fired EGUs that are currently equipped with SCRs, EPA followed the methodology laid out in the guidance evaluating daily, 7-day, and 30-day variability on a

[55] In the 2014 1-hour SO2 guidance, EPA suggested that hourly data for at least 3 to 5 years of stable operation (i.e., without changes that significantly alter emissions variability) may be needed to obtain a suitably reliable analysis. For EGUs such data sets are widely available, as required by 40 CFR part 75 and reported to the EPA. Similar emissions monitoring is required for a few additional source types under 40 CFR part 51, Appendix P, though these hourly data are not commonly made publicly available.

lb/MMBtu basis (Table D-1).[56,57] We show the estimated limits using the ratios for a seasonal rate at 0.08 lb/MMBtu. In all cases, we assume a daily emission rate of 0.14 lb/MMBtu (i.e., the value for coal-steam fleet-wide value) is appropriate given that fuel mix does not appear to substantially change the values.

To convert between the various rates, we can use the ratios of the 99th percentile values for the various time-periods. As an example, under the 2014 guidance, if we wanted to calculate a 30-day average rate that was comparably stringent to an hourly rate, we would take the ratio of the 99th percentile values (the 30-day value divided by the hourly value). This "adjustment factor" would then be multiplied by the hourly value that we want to convert (usually the hourly critical emission value, or CEV). Similarly, if we wanted to calculate a daily value, we would multiply the ratio of the 99th percentile values (the daily value divided by the hourly value) by the hourly critical emission value.

Comparably stringent 30-day rate = Hourly CEV*Ratio of 30-Day to hourly 99th Percentiles

Comparably stringent Daily rate = Hourly CEV*Ratio of Daily to hourly 99th Percentiles

Combining these two equations, by rearranging both to have the hourly CEV equal in both, and then solving for the comparably stringent daily rate:
Comparably stringent daily rate =
30-day rate * Ratio of Daily to hourly 99th Percentiles/ Ratio of 30-Day to hourly 99th Percentiles

EPA computed the following ratios or adjustment factors using the same data procedures used in creating the ratios in the 2014 guidance. The resulting unit-level 99th percentile ratios for various averaging times as well as various fleet-wide averages are shown in the excel file (Units_daily_rate_conversions_proposal.xlsx) included in the docket for the rule. Summary values are included in Table D-1. Substituting values from Table D-1 into the above equations 0.08 lb/MMBtu (a seasonal value taken to be equal to the 30-day rate)*0.97/0.56 = 0.14 lb/MMBtu. Thus, here, following the methodology that EPA outlined in the 2014 guidance, EPA concludes that a long-term rate of 0.08 lb/MMBtu could be considered to be comparably stringent to a short-term rate of 0.14 lb/MMBtu. The graphs in Figure D-1 show that for units fully operating their controls (i.e. achieving the 0.08lb/MMBtu seasonal rate), the daily limits are unlikely to be binding if an SCR is present.

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[56] Because of the method for calculating the rate, which is the sum of the daily emissions divided by the daily heat input utilized, hours where the unit does not operate will not impact the calculation.

[57] For this assessment, we assume that the 30-day and seasonal rates would be at comparable levels. Clearly, a 30-day rate would have a larger variability than a seasonal rate, but this should be relatively small since a seasonal value would include roughly one fifth of the values in the 30-day rate. Here, with just a few ozone seasons included, EPA did not believe it could reasonably estimate a 99th percentile variability in seasonal values.

Table D-1. Ratios to convert between various time-averages, applied to a 0.08 lb/MMBtu seasonal limit.

Unit Plant Type	Fuel	Ratio of NOx OS 99th Percentiles (30 Day Over Hour)	Ratio of NOx OS 99th Percentiles (Day Over Hour)	Ratio of NOx OS 99th Percentiles (Hour Over Hour)	Conversion of Default Seasonal SCR Rate to a Comparably Stringent Day Rate (lb/MMBtu)
coal steam	Fleet avg	0.56	0.97	1	0.14
coal steam	Bituminous	0.53	0.93	1	0.14
coal steam	Bituminous, Subbituminous	0.56	0.99	1	0.14
coal steam	Lignite	0.73	1.14	1	0.12
coal steam	Subbituminous	0.64	1.01	1	0.13
O/G Steam	SCR	0.68	0.83	1	0.10

E. Preliminary Environmental Justice Screening Analysis

In addition to the considerations above, EPA also considered potential environmental justice concerns.[58] EPA's EJ Technical Guidance[59] states that: "A regulatory action may involve potential environmental justice concerns if it could: (1) Create new disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples through the action under development." In this TSD, EPA uses a screening analysis to identify the potential for coal-fired EGUs to contribute to air pollution in areas with potential EJ concerns in relatively close proximity to the facility.

This initial screening analysis examines whether air pollution emitted from each individual facility might reach any communities with potential environmental justice concerns. Such an impact would support further consideration of additional pollution limits imposed at that facility to address existing disproportionate impacts. This screening-level analysis helped EPA identify potential concerns at the start of proposed rule development, while subsequent analysis presented in the RIA provide a robust evaluation of the distributional impacts of the requirements proposed in this action. These two sets of analyses are distinct but complementary – the screening analysis presented in this TSD evaluates the potential for environmental justice concerns at a facility level early in the process, and the environmental justice analyses presented in the RIA estimate the ultimate impacts of the proposed rule.

Based on this screening analysis, nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. While this screen does not identify all potentially impacted downwind areas or quantify the downwind impact of these sources (the aggregate impact of which is evaluated and discussed in the RIA), it does demonstrate that the potential exists for these sources to affect areas facing pre-existing disproportionate impacts. An overview of the methodology is described below.

Methodology

The screening assessment in this TSD is carried out in two parts. First, to estimate which census block groups have some potential to be affected by emissions from each EGU, EPA used NOAA's Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model to generate forward trajectories for large coal-fired EGUs located in linked upwind states under this proposed rule.[60] A forward trajectory is a modeled parcel of air that moves forward (i.e.,

[58] A potential EJ concern is defined as "the actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and indigenous peoples in the development, implementation and enforcement of environmental laws, regulations and policies" (U.S. EPA, 2015a). For analytic purposes, this concept refers more specifically to "disproportionate impacts on minority populations, low-income populations, and/or indigenous peoples that may exist prior to or that may be created by the proposed regulatory action" (U.S. EPA, 2015a).

[59] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions

[60] The HYSPLIT model determines the pathway of a modeled parcel of air using the NOAA's National Center for Environmental Information North American Mesoscale Forecast System 12 kilometer forecast gridded meteorology

downwind) due to winds and other meteorological factors. For each EGU, we used the HYSPLIT model to simulate the downwind path of air parcels passing individual EGUs four times per day—12:00 AM, 6:00 AM, 12:00 PM, and 6:00 PM (local standard time). For simplicity, in order to facilitate an initial screening-level analysis, EPA limited trajectories to the period June 1 to August 31 for the years 2017 to 2019. In addition, EPA ran each trajectory for only 24 hours. While the horizontal spatial resolution of the HYSPLIT model is based on 12-km meteorology (limiting our ability to resolve spatial differences less than 12 kilometers), we ran model simulations over 1,100 times for each facility (4 runs a day across 92 ozone season days for 3 years). These trajectories reflect a modeled air parcel's coordinates and elevation at every hour downwind of each EGU stack.[61] For this analysis, we limit our evaluation to coordinates of those trajectories that are within the continental United States and within 500 meters of ground level for simplicity in this initial screen. While the 24-hour transport time and 500 meter elevation used in this screening analysis identifies many of the near-source areas that are the most frequently impacted, emissions can travel over larger distances and longer times and have substantive air quality impacts downwind (i.e., those impacts are analyzed in the RIA).[62]

It is important to note that unlike the other models used to quantify downwind ozone concentrations related to this proposed rule, the HYSPLIT model is not a photochemical model – the model does not include chemical transformation and does not provide estimates of downwind pollutant concentrations.[63] We are using HYSPLIT trajectories in a qualitative way to examine the spatial patterns of pollutant transport from EGUs.[64] The model results simply simulate the path that the wind would carry a modeled parcel of air from the stack(s) of each EGU.[2] Consistent with the intent of this screening analysis, this model provides information about where non-reactive pollutants might initially travel from each EGU over a limited 24-hour period but does not quantify the magnitude of impact at any given location.

Next, EPA screened those downwind areas to identify census block groups with potential environmental justice concerns. The intent of this screen is to broadly identify areas potentially experiencing pre-existing disproportionate impacts, and as such, it does not quantify ozone-specific health risks. The screen was performed using data from EPA's EJSCREEN, an environmental justice mapping and screening tool that includes 11 different environmental

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dataset (NAM-12) (https://www.ncei.noaa.gov/access/metadata/landing-page/bin/iso?id=gov.noaa.ncdc:C00630). The horizontal resolution of the NAM-12 dataset is 12.191 kilometers, the vertical resolution is 26-layers from 1000 to 50 hecto Pascals, and the temporal resolution is 3-hours. (Stein et al., 2015, Draxler and Hess, 1998).

[61] The HYSPLIT model output results for each forward trajectory including the originating EGU, the coordinates and elevation above ground for each hour of the trajectory, and the trajectory elapsed time since release from the EGU are uploaded into an Oracle database. Within the Oracle database, the trajectory coordinates are used to construct line segments that can be displayed within a geographic information system (GIS) software package to overlay each modeled forward trajectory. The use of GIS allows a user to overlay HYSPLIT trajectories over census blocks of interest display the likely path that EGU emissions may travel in the absence of atmospheric residence time, chemical dispersion, or atmospheric deposition.

[62] For example, in 2016, the EPA used HYSPLIT to examine 96-hour trajectories and altitudes up to 1,500 meters in a corollary analysis to the source apportionment air quality modeling to corroborate upwind state-to-downwind linkages. Details of this analysis can be found in Appendix E ("Back Trajectory Analysis of Transport Patterns") of the Air Quality Modeling Technical Support Document for the Final Cross State Air Pollution Rule Update, which is available at: https://www.epa.gov/sites/default/files/2017-05/documents/aq_modeling_tsd_final_csapr_update.pdf

[63] The HYSPLIT model is run assuming the air parcel is neutrally buoyant and inert (i.e., without any dispersion, deposition velocity, or atmospheric residence time constraints).

[64] In general, pollutant concentrations are the result of transport, dispersion, and transformation. As noted, this analysis does not consider photochemical transformations.

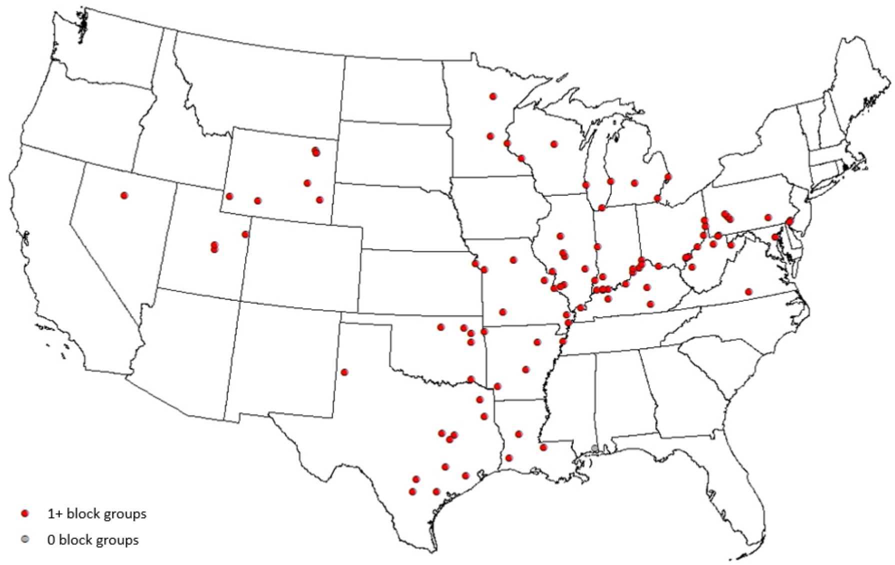
indicators and 6 different demographic indicators.[65] For this analysis, EPA evaluated the available information at the census block group level for one environmental indicator, ozone,[66] and one demographic indicator, percent low-income.[67] Note that this screening analysis is limited to a single environmental burden indicator (pre-existing ozone exposure), and does not consider the exposure and vulnerability of communities to multiple environmental burdens and their cumulative impacts. For further discussion of these indicators and the other indicators currently available in the EJSCREEN tool, see the EJSCREEN Technical Documentation.

Using these indicators to represent environmental burden and vulnerability generally, the EPA identified block groups for which these two indicators each exceeded the 80th percentile on a national basis. The 80th percentile threshold has been identified by the Agency in early applications of EJSCREEN as an initial screening filter and has been used in past screening experience to identify areas that may warrant further review, analysis, or outreach.[68] While communities exceeding this threshold may be exposed to pollution and potentially vulnerable to its impacts, it is important to note that EPA is not designating these areas as being "EJ communities." In line with this, the results of this screen should not be interpreted to suggest the absence of environmental justice concerns in areas that fail to meet this screening threshold. Rather, populations residing in these downwind areas are identified as being amongst the 20% of the US population with the highest values for each of the respective EJSCREEN indicators.

In the final step of the screening analysis, EPA combined the results of the previous two steps by layering the modeled HYSPLIT trajectories over census block groups with potential EJ concerns to identify the EGUs that have the potential to impact those areas. These are EGUs whose HYSPLIT trajectories cross over some portion of census block groups that meet the screening criteria above. EGUs with at least one block group exceeding the screening threshold that intersect with the EGU's respective HYSPLIT trajectory are highlighted in the figure below. When viewed comprehensively, the results are used to provide a reasonable approximation of downwind areas potentially exposed to air pollutants from each facility within a 24-hour period from emissions for the 2017-2019 time period. The map in Figure 1 shows the number of block groups exceeding the screening threshold that are identified as being downwind from each EGU, based on this particular analysis.

[65] U.S. Environmental Protection Agency (EPA), 2019. EJSCREEN Technical Documentation.
[66] Ozone summer seasonal average of daily maximum 8-hour concentration in air in parts per billion (2017)
[67] The percent of a block group's population in households where the household income is less than or equal to twice the federal "poverty level."
[68] U.S. Environmental Protection Agency (EPA), 2019. EJSCREEN Technical Documentation.

Figure E-1. Number of Block Groups Downwind from Each EGU that Exceed the Screening Threshold



F. Assessment of the Effects of Ozone on Forest Health

Air pollution can impact the environment and affect ecological systems, leading to changes in the ecological community and influencing the diversity, health, and vigor of individual plant species. When ozone is present in the environment, it enters the plant through the stomata and can interfere with carbon gain (photosynthesis) and allocation of carbon within the plant, making fewer carbohydrates available for plant growth, reproduction, and/or yield (2020 PA, section 4.3.1 and 2013 ISA, p. 1-15).[69],[70] Ozone can impact a variety of commercial and ecologically important species throughout the United States. These include forest tree and herbaceous species as well as crops. Such effects at the plant scale can also be linked to an array of effects at larger spatial scales and higher levels of biological organization, causing impacts to ecosystem productivity, water cycling, ecosystem community composition and alteration of below-ground biogeochemical cycles (2020 PA, section 4.3.1 and 2013 ISA, p. 1-15)..[71] With the data sets available to the Agency, here, we focus on selected forest tree species.

Assessing the impact of ozone on forests in the United States involves understanding the risk to tree species from ozone concentrations in ambient air and accounting for the prevalence of those species within the forest. Across several reviews of the ozone NAAQS and based on longstanding body of scientific evidence, EPA has evaluated concentration-response functions which relate ozone exposure to growth-related effects in order to consider the risk of ozone-related growth impacts on forest trees (2020 PA, section 4.3.3, 2013 ISA and 2020 ISA). For this purpose, EPA has focused on cumulative, concentration-weighted indices of exposure, such as the W126-based cumulative exposure index (2020 PA, section 4.3.3.1.1, 2020 ISA, section ES.3). Measured ozone concentrations in ambient air of the United States are used to calculate the W126-based index as the annual maximum 3-month sum of daytime hourly weighted ozone concentrations, averaged over 3 consecutive years. The sensitivity of different trees species varies about the growth impacts of ozone exposure. Based on well-studied datasets relating W126 index to reduced growth, exposure response functions have been developed for 11 tree species (2020 PA, section 4.3.3.1.2 and Figure 4-3 and 2013 ISA, section 9.6). For these species, the impact from ozone exposure has been determined by exposing seedlings to different levels of ozone concentrations over one or more seasons (which have been summarized in terms of W126 index) and measuring reductions in growth (which are then summarized as "relative biomass loss"). The magnitude of ozone impact on a forest community will depend on the prevalence of different tree species of relatively more versus less sensitivity to ozone and the abundance in the community.

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[69] U.S. EPA (2020). Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Research Triangle Park, NC. EPA-452/R-20-001. Available *https://www.epa.gov/sites/production/files/2020-05/documents/o3-final_pa-05-29-20compressed.pdf*

[70] U.S. EPA (2020). Integrated Science Assessment for Ozone and Related Photochemical Oxidants. U.S. Environmental Protection Agency. Washington, DC. Office of Research 3A-35 and Development. EPA/600/R-20/012. Available at: *https://www.epa.gov/isa/integrated-science-assessment-isa-ozone-and-related-photochemical-oxidants*.

[71] U.S. EPA (2013). Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Final Report). Office of Research and Development, National Center for Environmental Assessment. Research Triangle Park, NC. U.S. EPA. EPA-600/R-10-076F. February 2013. Available at: *https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P100KETF.txt*.

Some of the most common tree species in the eastern United States, where the benefits from this rule will be most pronounced, are black cherry (*Prunus serotina*), yellow or tulip-poplar (*Liriodendron tulipifera*), sugar maple (*Acer saccharum*), eastern white pine (*Pinus strobus*), Virginia Pine (*Pinus virginiana*), red maple (*Acer rubrum*), and quaking aspen (*Populus trenuloides*). Since 2008, EPA has assessed the impact of ozone on these tree species within the eastern United States for the period from 2000 to 2018 as part of the Clean Air Market Division (CAMD) annual power sector programs progress report.[72] Over this time period ozone concentrations have improved substantially because of various emission reduction programs, such as NBP, CAIR, CSAPR, CSAPR Update, Revised CSAPR Update, and other local and mobile source reductions such as Tier2 and Tier3 rules. Past EPA assessments have shown that the improvements in ozone are evident both for the regulatory metric, 3-year average of 4th highest 8-hr daily maximum ozone concentration, and for the W126 metric.[73] In forests where certain sensitive species dominate the forest community, the estimates of relative biomass loss from ozone have decreased substantially. However, for the period from 2017–2019, the eastern United States still has areas where the species-weighted relative biomass loss estimated from ozone for the seven common trees listed above is up to 11.5% (Figure F-1)[74].

Ozone levels are expected to continue to decrease through 2026 based on model projection of the impacts on ozone concentrations resulting from baseline "on the books" control programs as well as by emission reductions under this rule. In a past analysis, as ozone declines, estimates of relative biomass loss of these trees' species will also decline as they have from 2000 to 2019 (to be updated in 2022), indicating this proposed rule would result in increased protection of forest ecosystems and resources. Under this rule, ozone concentrations are expected to decline faster than without the rule (e.g., under the base case). While EPA does not have the tools to quantify the expected level of improvement at this time, based on the previous relationships between ozone design values and W126 determined as part of the review of the 2020 ozone NAAQS (2020 PA, section 4D.3.2.3 and Table 4D-12), W126 values are expected to improve as design values decrease. As described in the preamble, the rule is expected to improve air quality as controls are optimized and installed between 2023 and 2026.

The reductions from this rule are likely to provide further protection to natural forest ecosystems by reducing the potential for ozone-related impacts.

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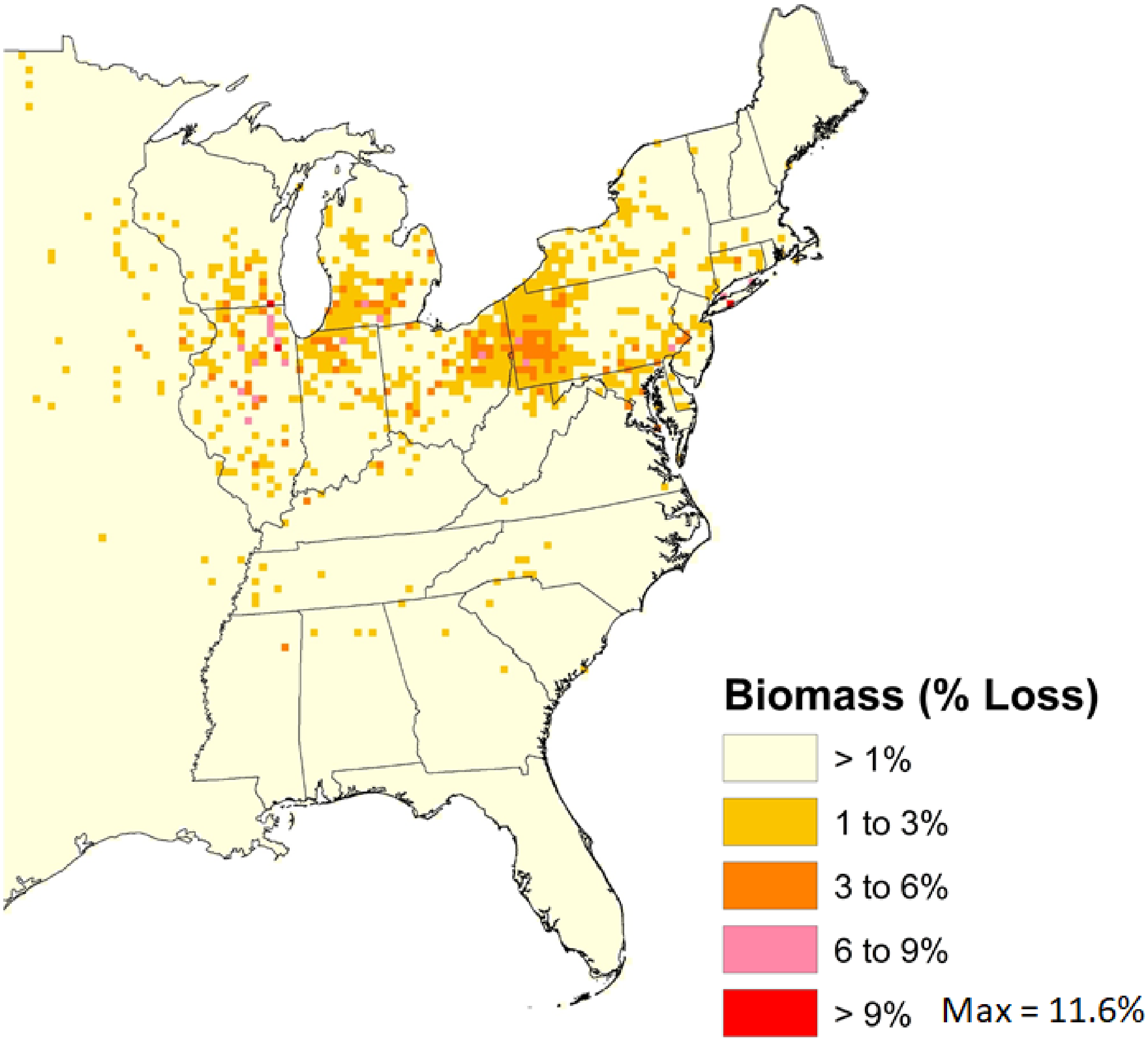
[72] See the annual progress reports for several recent years at https://www3.epa.gov/airmarkets/progress/reports/index.html, https://www3.epa.gov/airmarkets/progress/reports/pdfs/2019_full_report.pdf, and https://www3.epa.gov/airmarkets/progress/reports/pdfs/2018_full_report.pdf

[73] U.S. EPA (2020). Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Research Triangle Park, NC. EPA-452/R-20-001. Available *https://www.epa.gov/sites/production/files/2020-05/documents/o3-final_pa-05-29-20compressed.pdf*

[74] To estimate the biomass loss for forest ecosystems across the eastern United States, the biomass loss for each of the seven tree species was calculated using the three-month, 12-hour W126 exposure metric at each location, along with each tree's individual C-R functions. The W126 exposure metric was calculated using monitored ozone data from CASTNET and AQS sites, and a three-year average was used to minimize the effect of variations in meteorological and soil moisture conditions. The biomass loss estimate for each species was then multiplied by its prevalence in the forest community using the U.S. Department of Agriculture (USDA) Forest Service IV index of tree abundance calculated from Forest Inventory and Analysis (FIA) measurements.

Figure F-1: Estimated Black Cherry, Yellow Poplar, Sugar Maple, Eastern White Pine, Virginia Pine, Red Maple, and Quaking Aspen Biomass Loss due to Ozone Exposure for 2016-2018.



See the annual progress reports at https://www3.epa.gov/airmarkets/progress/reports/index.html and https://www3.epa.gov/airmarkets/progress/reports/pdfs/2018_full_report.pdf

Appendix A: State Emission Budget Calculations and Engineering Analytics

See Excel workbook titled "Proposed Rule State Emission Budget Calculations and Engineering Analytics" on EPA's website and in the docket for this rulemaking

Appendix B: Description of Excel Spreadsheet Data Files Used in the AQAT

EPA placed the Ozone_AQAT_Proposal.xlsx Excel workbook file in the docket that contains all the emission and CAMx air quality modeling inputs and resulting air quality estimates from the AQAT. The following bullets describe the contents of various worksheets within the AQAT workbook:

State-level emissions

- "2026_EA" and "2023_EA" contain EGU emissions measurements and estimates for each state. Various columns contain the 2021 OS measured emissions, and then emissions for the engineering base along with each of the cost thresholds (including generation shifting).
- "RIA_cases" contains state specific ozone-season NO_X emission total EGU and non-EGU emissions and emissions changes for the 2023 and 2026 proposed rule, as well as less and more-stringent cases. The emission changes are relative to the 2023 and 2026 base cases modeled in CAMx.
- "NO_X_nonCEM" has a breakdown of the point EGU nonCEM emission inventory component used in the air quality modeling.
- "non-EGU emiss" has the total anthropogenic emission reductions by state and Tier for each of the non-EGU cases.
- "2026_OS NO_X" and "2023_OS NO_X" each of these worksheets reconstructs total anthropogenic emissions for the year, with various EGU emission inventories for different cost threshold (including the engineering base case). The total anthropogenic emissions can be found for each state in columns AG through AL. These totals are then compared to the 2026fj emission level (column P on the "2026_OS NOx" worksheet) to make a fractional change in emissions in columns AM through AR. For 2026, Non-EGU emissions change and fractional change) are found in columns AS through AY.

Air quality modeling design values and contributions from CAMx

- "2023fj_All" contains average and maximum design values as well as state by state contributions for the 2023fj base case modeled in CAMx.
- "2026fj_All" contains average and maximum design values as well as state by state contributions for the 2026fj base case modeled in CAMx.
- "2026fj_30NOx" contains average and maximum design values as well as state by state contributions for the case modeled in CAMx where EGU and non-EGU emissions were reduced by 30%.
- "2016_2023_2026_2032 DVs contains average and maximum design values for each receptor for each year.
- 2026fj_receptor_list contains a list of the receptors whose average and/or maximum design values are greater than or equal to 71 ppb in 2026.

Calibration factor creation and assessment

- "2026to2026w30_calib_(rec, stat)" includes the state-by-state and receptor-by-receptor calculation of the calibration factors based on the 2026 base and 2026 air quality modeling where EGU and non-EGU NO_X emissions were reduced by 30%. The calibration factors can be found in columns I through BF.

- “2026to2023_calib_(rec, state)” includes the state-by-state and receptor-by-receptor calculation of the calibration factors based on the 2026 base and 2023 base contributions, and fractional change of 2023 emissions relative to 2026 emissions. The calibration factors can be found in columns I through BF.

Air quality estimates

- ”summary_DVs_2026” contains the average and maximum design value estimates (rounded to two decimal places) for receptors that were nonattainment or maintenance in the 2026 air quality modeling base case. Values using the Step 3 approach for each cost threshold are shown starting in column L. Under this approach, the maximum contribution to remaining receptors is shown in columns AF through AM. Furthermore, a set of design value estimates are shown (columns AR through AY) for a control scenario, where all states that are originally linked in the base make adjustments to different cost levels. Adjustment to cells I1 and I2 will result in interactive adjustment for the other worksheets and will adjust the design values in columns I (the Step 3 approach) and J (a control scenario approach where the geography remains fixed) and the maximum contributions to remaining linkages in column AD. Design value estimates for the proposed rule and less and more stringent alternatives for the RIA are shown in columns BC, BD, and BE (note that the linked, home, and nonlinked states are assigned the same emission value). The maximum contribution to remaining receptors is shown in columns AN through AP. The alternative calibration factor simulation results are shown in columns BJ and BK. Each column contains average design values followed by maximum design values, below.
- ”summary_DVs_2023” contains the average and maximum design value estimates (rounded to two decimal places) for receptors that were nonattainment or maintenance in the 2023 air quality modeling base case. Values using the Step 3 approach for each cost threshold are shown starting in column L. Under this approach, the maximum contribution to remaining receptors is shown in columns AD through AI. Furthermore, a set of design value estimates are shown (columns AN through AS) for a control scenario, where all states that are originally linked in the base make adjustments to different cost levels. Adjustment to cells I1 and I2 will result in interactive adjustment for the other worksheets and will adjust the design values in columns I (the Step 3 approach) and J (a control scenario approach where the geography remains fixed) and the maximum contributions to remaining linkages in column AB. Each column contains average design values followed by maximum design values, below. Design value estimates for the proposed rule and less and more stringent alternatives for the RIA are shown in columns BC, BD, and BE (note that the linked, home, and nonlinked states are assigned the same emission value). The maximum contribution to remaining receptors is shown in columns AJ through AL.
- “2023_scenario”and “2026_scenario” contains the average and maximum design value estimates (as well as the individual state’s air quality contributions) for a particular scenario identified in cells H2 and H3. The fractional emission changes for each of the linked and unlinked states are shown in rows 2 and 3.
- “2023_scenario_links” and “2026_scenario_links” contains the individual state’s air quality contributions for a particular receptors that remain at or above 71 ppb for the scenario identified in cells I1 and I2.

- “2026_control_fixed” and “2023_contol_fixed” contains the average and maximum design value estimates (as well as the individual state’s air quality contributions) for a particular scenario identified in cells H2 and H3. States that are “linked” to any receptor in the geography are assigned the values in row 2 while nonlinked states are assigned the values in row 3. Note that,only the “home” states, that are linked to receptors in other states are assigned the “linked” state values in row 2.
- “2026_scenario_alt_calib” contains the average and maximum design value estimates (as well as the individual state’s air quality contributions) for a particular scenario identified in cells H2 and H3. The fractional emission changes for each of the linked and unlinked states are shown in rows 2 and 3. This uses the calibration factor based on the 2023 air quality modeling, rather than the calibration factor based on the 2026 air quality modeling with the 30% reduction from EGUs and non-EGUs.
- “2026_scenario_eng_base” and “2023_scenario_eng_base” contain air quality contributions and design value estimates for the two base cases using the engineering analysis emission estimates for EGUs.
- The individual scenario worksheets labeled:
    - “2023_scenario_base”,
    - “2023_scenario_SCRopt”,
    - “2023_scenario_SCRoptwCC”,
    - “2023_scenario_SNCRopt”,
    - “2023_scenario_SNCRoptwCC”,
    - “2023_scenario_newSCR”,
    - “2026_scenario_base”,
    - “2026_scenario_SCRopt”,
    - “2026_scenario_SCRoptwCC”,
    - “2026_scenario_SNCRopt”,
    - “2026_scenario_SNCRoptwCC”,
    - “2026_scenario_newSCR”,
    - “2026_scenario_Tier1”,
    - “2026_scenario_Tier1and2”,
    - “2023_control_fixed_base”,
    - “2023_control_fixed_SCRopt”,
    - “2023_control_fixed_SCRoptwCC”,
    - “2023_control_fixed_SNCRopt”,
    - “2023_control_fixed_SNCRoptwCC”,
    - “2023_control_fixed_newSCR”,
    - “2026_control_fixed_base”,
    - “2026_control_fixed_SCRopt”,
    - “2026_control_fixed_SCRoptwCC”,
    - “2026_control_fixed_SNCRopt”,
    - “2026_control_fixed_SNCRoptwCC”,
    - “2026_control_fixed_newSCR”,
    - “2026_control_fixed_Tier1”,
    - “2026_control_fixed_Tier1and2”
    - “2023_proposed_rule”
    - “2023_less_stringent”

- “2023_more_stringent”
- “2026_proposed_rule”
- “2026_less_stringent”
- “2026_more_stringent”

contain static air quality contributions and design value estimates for all monitors for the particular year and scenario.

Appendix C: IPM Runs Used in Transport Rule Significant Contribution Analysis

Table C-1 lists IPM runs used in analysis for this rule. The IPM runs can be found in the docket for this rulemaking under the IPM file name listed in square brackets in the table below.

Table Appendix C-1. IPM Runs Used in Transport Rule Significant Contribution Analysis

Run Name **[IPM File Name]**	**Description**
Air Quality Modeling Base Case EPA620_BC_1K	Model run used for the air quality modeling base case at steps 1 and 2, which includes the national Title IV SO2 cap-and-trade program; NO_X SIP Call; the Cross-State Air Pollution trading programs, and settlements and state rules. It also includes key fleet updates regarding new units, retired units, and control retrofits that were known by Summer of 2021.
Illustrative Base Case with optimization technology + LNB upgrade EPA620_TR_2e	Model run used as the base case for the Illustrative Analysis of cost threshold analyses. Based on the air quality modeling base case, but with projected retirements and retrofits in 2023 limited. Also assumes optimization of existing post-combustion controls and upgrade of combustion controls if mode 3>1. Imposes state-level generation constraints starting in 2023 for fossil-fuel fired units greater than 25 MW that is equal to Air Quality Modeling Base Case levels.
Illustrative Base Case with optimization technology + LNB upgrade + SCR retrofit EPA620_TR_4e	Imposes state-level generation constraints starting in 2023 for fossil-fuel fired units greater than 25 MW that is equal to Illustrative Base Case levels. Also assumes optimization of existing post-combustion controls and upgrade of combustion controls if mode 3<mode 1. Assumes units lacking post combustion controls (SCR or SNCR) retrofit to combustion controls in the 2025 run year.
Illustrative $1,800/ton Cost Threshold EPA617_CURR_3d	Same as the, Illustrative Base Case with optimization technology + LNB upgrade but with $1,800/ OS NO_X ton price signal applied in the ozone season.
Illustrative $10,000/ton Cost Threshold EPA617_CURR_4d	Same as the Illustrative Base Case with optimization technology + LNB upgrade + SCR retrofit, but with $10,000/OS NO_X ton price signal applied in the ozone season.

Appendix D: Generation Shifting Analysis

Table Appendix D-1. Tons of EGU NO_X Reduction Potential from Shifting Generation Compared to Adjusted Historical Baseline Emissions.

State	2023 Baseline (Tons)	2023 Reductions from generation Shifting at $1,800/Ton	2023 Reductions from generation Shifting at $1,800/Ton (%)	2026 Baseline (Tons)	2026 Reductions from generation Shifting at $1,800/Ton	2026 Reductions from generation Shifting at $1,800/Ton (%)
Alabama	6,648	231	3%	6,701	0	0%
Arkansas	8,955	38	0%	8,728	108	1%
Delaware	423	-4	-1%	473	0	0%
Illinois	7,662	-127	-2%	7,763	350	5%
Indiana	12,351	326	3%	9,737	206	2%
Kentucky	13,900	1,213	9%	13,211	188	1%
Louisiana	9,987	-96	-1%	9,854	0	0%
Maryland	1,208	5	0%	1,208	11	1%
Michigan	10,737	-15	0%	9,129	56	1%
Minnesota	4,207	107	3%	4,197	48	1%
Mississippi	5,097	0	0%	5,077	-1	0%
Missouri	20,094	444	2%	18,610	127	1%
Nevada	2,346	0	0%	2,438	0	0%
New Jersey	915	11	1%	915	11	1%
New York	3,927	100	3%	3,927	100	3%
Ohio	10,295	765	7%	10,295	355	3%
Oklahoma	10,463	0	0%	10,283	40	0%
Pennsylvania	12,242	309	3%	11,738	409	3%
Tennessee	4,319	-25	-1%	4,064	0	0%
Texas	40,860	1,190	3%	39,186	1,423	4%
Utah	15,500	512	3%	9,679	-16	0%
Virginia	3,415	-24	-1%	3,243	30	1%
West Virginia	14,686	547	4%	14,686	429	3%
Wisconsin	5,933	-76	-1%	3,628	102	3%
Wyoming	10,191	958	9%	10,249	90	1%

Appendix E: Feasibility Assessment for Engineering Analytics Baseline

Similar to the Revised CSAPR Update Final Action, EPA analyzed and confirmed that the assumed fleet operations in its baseline emissions and emission control stringency control levels as implemented through estimated budgets were compatible with future load requirements by verifying that new units in addition to the existing fleet would provide enough generation, assuming technology-specific capacity factors, to replace the retiring generation expected to occur in years 2023 through 2026. EPA assessed generation adequacy specific to the states covered under this action. EPA uses these observations to determine whether any assumed replacement generation from the existing fleet is necessary to offset the announced retirements and continue to satisfy electricity load. Additionally, EPA looked at whether the combination of new units (both fossil and non-fossil) provide sufficient new generation to replace retiring generation. In this case, EPA found that the new unit generation from fossil and renewable generation would exceed the generation from retiring units in all three scenarios examined, indicating that no further replacement generation from existing units is needed. Moreover, EPA found the change in generation from the covered fossil units to be within the observed historical trend.

- EPA first identified the collective baseline heat input and generation from the states covered in this action and compared it to historical trends for these same states (Scenario 1). This illustrated that the assumed heat input and generation from fleet turnover was well within with recent historical trends (see tables Appendix E-1, and Appendix E-2 below).
- EPA then compared the collective baseline heat input and generation from the states covered in this action to a scenario where fossil generation remains at 2019 levels instead of continuing to decline (Scenario 2).
- Finally, EPA identified the 2021 Energy Information Administration's Annual Energy Outlook (EIA AEO) annual growth projections from 2020 through 2026 total electricity demand levels (1.1%) from its reference case, and estimated an upperbound future year scenario where covered fossil generation grew at levels matching this fleet-wide total growth rate (Scenario 3).[75]
- EPA's assessment illustrates the amount of generation in its baseline, factoring in retirements and new fossil units, is more than sufficient to accommodate all three scenarios.[76] For instance, generation from covered fossil sources in these states has dropped at an average rate greater than 1.6% per year between 2018 and 2021 (877 TWh to 833 Twh). However, EPA's assumed baseline generation from covered fossil sources for the states reflects a rate of decline less than 2% per year. See Table Appendix E-2.
- EPA then identified new RE capacity under construction, testing, or in site prep by 2022. For years beyond 2022, EPA also identified new RE capacity that was planned but with

[75] Department of Energy, Annual Energy Outlook 2020. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2020&cases=ref2020&sourcekey=0
[76] Based on historical trends, modeling, and company statements, EPA expects levels similar to scenario 1 and scenario 2 to be most likely.

regulatory approvals pending for years 2023 and beyond (as this capacity is unlikely to have yet started construction).[77]

- EPA calculated and added the RE generation values to the fossil baseline to estimate future year generation in the state (see Table Appendix E-2). EPA used a capacity factor of 42.7% for wind, 21.6% for solar, and 65% for NGCC.
- Using these technology-specific capacity factors based on past performance and IPM documentation, EPA anticipated over 40 TWh from new non-fossil generation already under construction or being planned with regulatory approval received. This combined with the baseline generation from existing units exceeds the expected generation load for the states under all three scenarios.[78]

- Not only is the future baseline generation level assumed in EPA's engineering analysis well within the recent historical fossil generation trend (See Table Appendix E-2) on its own (which illustrates no need for replacement generation), but when added to the amount of potential new generation from RE (over 40 TWh), exceeds the generation assuming no change (scenario 2) and the upper bound analysis for future covered fossil generation that assumes 1.1% growth from the existing fossil fleet (scenario 3). This indicates that available capacity and generation assumed would serve load requirements in this upper bound scenario.

  Not included in the tables below nor in EPA's baseline, but listed in the latest EIA 860m is even more planned NGCC combined cycle for years 2023 and 2024 that is pending regulatory approval. Assuming some of this (low emitting generation) becomes available in the outer years, that constitutes additional generation that further exceeds EPA's upperbound generation levels below – further bolstering the observation that no replacement generation from existing units needs to be assumed to fill generation from retiring units.

[77] Department of Energy, EIA Form 860, Generator Form 3-1. 2020. Available at https://www.eia.gov/electricity/data/eia860/

[78] While EPA notes the baseline generation exceeds the covered fossil load in all three scenarios in Table F-3, EPA anticipates scenarios 1 and 2 being more representative of likely covered fossil load based on historical trends, future modeling, and utility resource plans.

Table Appendix E-1: Heat Input Change Due to Fleet Turnover (Historical and Future) Values for 2018-2021 reflect reported data, while 2023-2026 reflects assumed heat input.

Region	2018	2019	2020	2021	2023	2024	2025	2026
Alabama	388	352	327	322	327	327	327	338
Arkansas	220	203	160	193	202	202	202	197
California	254	219	265	301	226	226	226	226
Delaware	22	20	21	19	34	34	34	34
Illinois	397	332	283	334	245	242	242	232
Indiana	479	404	371	411	328	287	287	289
Kentucky	354	316	270	303	250	250	250	262
Louisiana	312	317	281	280	334	334	334	334
Maryland	105	92	82	88	78	93	93	93
Michigan	349	326	283	308	317	317	317	321
Minnesota	144	132	108	129	110	110	110	112
Mississippi	218	211	224	190	199	199	199	199
Missouri	313	269	254	288	240	240	240	254
Nevada	108	98	100	103	103	103	103	104
New Jersey	151	146	119	120	142	142	142	142
New York	238	202	234	240	222	222	222	221
Ohio	405	402	395	400	352	352	352	368
Oklahoma	276	235	232	213	235	235	235	233
Oregon	58	63	50	56	55	55	55	56
Pennsylvania	487	509	535	565	524	524	524	518
Tennessee	184	190	165	180	169	169	169	156
Texas	1,530	1,501	1,355	1,403	1,434	1,418	1,418	1,382
Utah	143	133	133	164	130	130	130	107
Virginia	251	249	261	215	258	249	249	273
West Virginia	309	295	268	313	260	260	260	251
Wisconsin	222	192	195	221	194	185	185	137
Wyoming	186	164	163	176	152	152	152	164
Total	8,101	7,570	7,137	7,535	7,121	7,058	7,058	7,003

Appendix E-2: Assumed Baseline OS Generation and Expected New Build Generation from Covered Fossil Units (TWh)

	2023	2024	2025	2026
Scenario 1 - Generation Levels (with continued pace of 1.6% decline)	806	793	780	767
Scenario 2 - Generation Levels (no change from 2021)	833	833	833	833
Scenario 3 - Generation Levels (1.1% growth from covered fossil)	843	852	862	872
Assumed Baseline Fossil Generation with Reported Fossil Retirement and Reported New Build	815	810	810	806
New Build (Non-Fossil)	40	57	64	75
Total Baseline Generation	**855**	**867**	**874**	**881**

Appendix F: State Emission Budgets and Variability Limits

State	2023 Emission Budgets (tons)	2023 Variability Limit (tons)	2024 Emission Budgets (tons)	2024 Variability Limit (tons)	2025 Illustrative Emission Budgets (tons)	2025 Illustrative Variability Limit (tons)	2026 Illustrative Emission Budgets (tons)	2026 Illustrative Variability Limit (tons)
Alabama	6,364	1,336	6,306	1,324	6,306	1,324	6,306	1,324
Arkansas	8,889	1,867	8,889	1,867	8,889	1,867	3,923	824
Delaware	384	81	434	91	434	91	434	91
Illinois	7,364	1,546	7,463	1,567	7,463	1,567	6,115	1,284
Indiana	11,151	2,342	9,391	1,972	8,714	1,830	7,791	1,636
Kentucky	11,640	2,444	11,640	2,444	11,134	2,338	7,573	1,590
Louisiana	9,312	1,956	9,312	1,956	9,179	1,928	3,752	788
Maryland	1,187	249	1,187	249	1,187	249	1,189	250
Michigan	10,718	2,251	10,718	2,251	10,759	2,259	6,114	1,284
Minnesota	3,921	823	3,921	823	3,910	821	2,536	533
Mississippi	5,024	1,055	4,400	924	4,400	924	1,914	402
Missouri	11,857	2,490	11,857	2,490	10,456	2,196	7,246	1,522
Nevada	2,280	479	2,372	498	2,372	498	1,211	254
New Jersey	799	168	799	168	799	168	799	168
New York	3,763	790	3,763	790	3,763	790	3,238	680
Ohio	8,369	1,757	8,369	1,757	8,369	1,757	8,586	1,803
Oklahoma	10,265	2,156	9,573	2,010	9,393	1,973	4,275	898
Pennsylvania	8,855	1,860	8,855	1,860	8,855	1,860	6,819	1,432
Tennessee	4,234	889	4,234	889	4,008	842	4,008	842
Texas	38,284	8,040	38,284	8,040	36,619	7,690	21,946	4,609
Utah	14,981	3,146	15,146	3,181	15,146	3,181	2,620	550
Virginia	3,090	649	2,814	591	2,948	619	2,567	539
West Virginia	12,478	2,620	12,478	2,620	12,478	2,620	10,597	2,225
Wisconsin	5,963	1,252	5,057	1,062	4,198	882	3,473	729
Wyoming	9,125	1,916	8,573	1,800	8,573	1,800	4,490	943

Appendix G: Figures Related to Preamble Section VI and Section VII

Figure 1 to Section VI.D.1 – EGU Ozone Season NOx Reduction Potential in 26 Linked States and Corresponding Total Reductions in Downwind Ozone Concentration at Nonattainment and Maintenance Receptors for Each Cost Threshold Level Evaluated (2023)

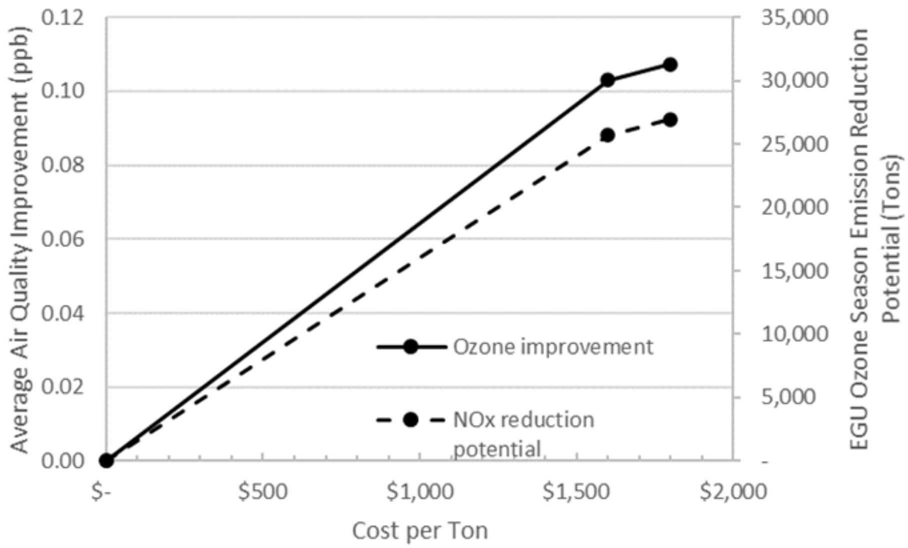


Figure 2 to Section VI.D.1: EGU Ozone Season NOx Reduction Potential in 23 Linked States and Corresponding Total Reductions in Downwind Ozone Concentration at Nonattainment and Maintenance Receptors for Each Cost Threshold Level Evaluated (2026)

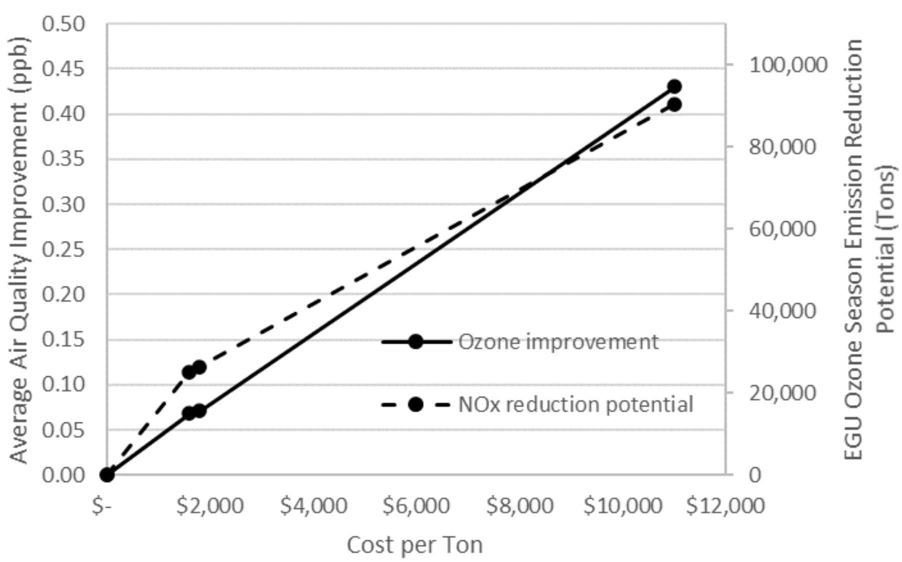
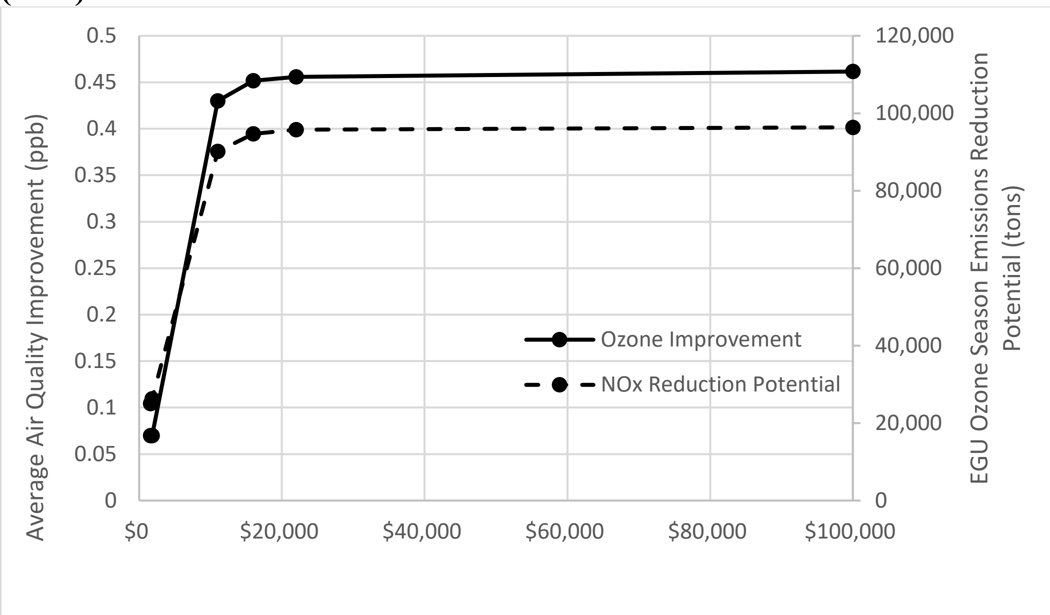


Figure 3 to Section VI.D.1: EGU Ozone Season NO_X Reduction Potential in 23 Linked States and Corresponding Total Reductions in Downwind Ozone Concentration at Nonattainment and Maintenance Receptors for Each Cost Threshold Level Evaluated and Illustrative Evaluation of Cost Thresholds beyond Identified Technology Breakpoints (2026)[79]



[79] For the evaluation of air quality impacts for the cost levels beyond our technology breakpoints (i.e., beyond $11,000 per ton), the EPA relies on an average air quality per ton reduction factor derived from its AQAT analysis. The EPA notes that these illustrative points (those beyond $11,000 per ton) reflect SCRs on steam units less than 100 MW and o/g steam units < 150 tons per season, combustion control upgrade on combustion turbines, and SCRs on combustion turbines > 100 MW respectively. These mitigation measures and costs are further discussed in the EGU NOx Mitigation Strategies Proposed Rule TSD.

Figure 1 to Section VII.B.1.c.i: New Madrid Unit 2 Daily Emissions Rate (2017 and 2019)