# Regulatory Impact Analysis for the Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

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Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

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## ACKNOWLEDGEMENTS

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### Overview

This document presents the regulatory impact analysis (RIA) for the final rule, the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS). This RIA provides the EPA's analysis of a variety of potential impacts (i.e., consequences) of the final rule and is used to inform the EPA and the public about these potential impacts. In the rule, the EPA promulgates implementation mechanisms to achieve enforceable emissions reductions required to eliminate ozone precursor emissions that significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in other states.[1] The initial phase of emissions reductions will begin in the 2023 ozone season with further emissions reductions being required in later years.

The EPA is promulgating new or revised FIPs for 23 states. For 22 states the FIPs include new $NO_X$ ozone season emission budgets for EGU sources, with implementation of these emission budgets beginning in the 2023 ozone season.[2] The EPA is expanding the Cross-State Air Pollution Rule (CSAPR) $NO_X$ Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require electric generating units (EGUs) within the borders of the 22 states to participate in a revised version of the CSAPR $NO_X$ Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of 12 states currently participating in the Group 3 Trading Program under FIPs or SIPs remain in the program, with revised provisions beginning in the 2023 ozone season. The FIPs also require affected EGUs within the borders of seven states currently covered by the CSAPR $NO_X$ Ozone Season Group 2 Trading Program (the "Group 2 trading program") under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period. Lastly, the EPA is issuing new FIPs for three

[1] The 2015 ozone NAAQS is an 8-hour standard that was set at 70 parts per billion (ppb). See 80 FR 65291 (December 28, 2015).

[2] In 2023, the 22 states with EGU reduction requirements include AL, AR, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, and WI. There are no EGU reductions being required from California, which if included would make 23 states.

states not currently covered by any CSAPR $NO_X$ ozone season trading program (Minnesota, Nevada, and Utah).

For non-electric generating units (non-EGUs), the FIPs that EPA is promulgating for 20 states include new $NO_X$ emissions limitations, with initial compliance dates for these emissions limitations beginning in 2026.[3]

Consistent with OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (2010), this RIA presents the benefits and costs of the final rule from 2023 through 2042. For the proposal RIA and this final RIA, we selected a 20-year analytical period because it is generally representative of and covers the lifetime of the capital equipment anticipated to be installed in response to the rule. Costs, benefits, and other impacts from compliance strategies are likely to occur beyond 2042. The estimated health benefits are expected to arise from reduced ozone and $PM_{2.5}$ concentrations, and the estimated climate benefits are from reduced greenhouse gas (GHG) emissions. The estimated costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity to comply with the revised version of the Group 3 trading program. The estimated costs for non-EGUs are the costs of installing and operating controls to meet the ozone season NOx emissions limitations. The estimated costs that the EPA reports for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs, which the EPA summarizes in Section X.B.2 of the final rule preamble and discusses in Chapter 4, Section 4.4 below. Unquantified benefits and costs are described qualitatively. The RIA also provides estimates of other impacts of the final rule including its effect on retail electricity prices, fuel production for electricity generation, EGU-related employment, and environmental justice (EJ) impacts.

## ES.1 Identifying Needed Emissions Reductions and Regulatory Requirements

To reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I), the final rule further limits ozone season $NO_X$ emissions from EGUs and non-EGUs using the same framework used by the EPA in developing the CSAPR. The Interstate Transport Framework provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter ($PM_{2.5}$) NAAQS: (1) identifying

[3] In 2026, the 20 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, and WV.

downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems (i.e., here, an amount of contribution equal to or greater than 1 percent of the NAAQS); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures. In this action, the EPA applies this 4-step Interstate Transport Framework for the Transport FIP for the 2015 ozone NAAQS.

For EGUs, in identifying levels of uniform control stringency the EPA assessed the same $NO_X$ emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available for EGUs: (1) fully operating existing SCR, including both optimizing $NO_X$ removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art $NO_X$ combustion controls; (3) fully operating existing SNCRs, including both optimizing $NO_X$ removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (i.e., emission reductions anticipated to occur from generation shifting from higher to lower emitting units). The selected levels of uniform control stringency were represented by \$1,800 per ton of $NO_X$ (2016\$) in 2023 and \$11,000 per ton of NOx (2016\$) in 2026.[4]

Based on this uniform control stringency analysis, the rule establishes $NO_X$ emissions budgets requiring fossil fuel-fired EGUs in 22 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25-megawatt (MW) capacity. Any new fossil fuel-fired EGU serving a generator with a nameplate capacity exceeding 25 MW capacity that meets the applicability criteria and is deployed in any of the states covered by this

[4] The EGU $NO_X$ Mitigation Strategies Final Rule TSD, in the docket (Docket ID No. EPA-HQ-OAR-2021-0688), describes how these costs per ton were chosen for the EGU stringency in this rule. Generation shifting is not included as a control strategy when establishing the budgets in the final rule. However, generation shifting is a control strategy that the EPA expects will be used for compliance. For additional discussion, please see Chapter 4.

rule's EGU ozone-season $NO_X$ program would be subject to the same requirements as other covered EGUs. For details on the derivation of emissions budgets, please see Section V.C. of the final rule preamble.

In this rule, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank, which is 21 percent of the sum of the state emissions budgets for the current control period until 2030 (at which point it declines to 10.5%), that were not included in previous CSAPR $NO_X$ ozone season trading programs. These enhancements will help maintain control stringency over time and improve emissions performance at individual units, offering an extra measure of assurance that existing pollution controls will be operated during the ozone season.

In this final action, the EPA is retaining the industries and many of the emissions unit types included in the proposal. At proposal, the EPA developed an analytical framework and applicability criteria to determine which industries and emissions unit types required NOx limitations in the non-electric generating unit "sector" (non-EGUs).[5,6] The rule includes ozone season $NO_X$ emissions limitations for non-EGUs with an initial compliance date of 2026 for 20 states. A summary of the non-EGU industries, emissions unit types, form of final emissions limits, and final emissions limits is presented below in Table ES-1. A more detailed summary of the emissions limits can be found in Section I.B. of the preamble. For a discussion of changes to emissions limits between the proposed FIP and the final rule, see Chapters 1 and 4 of this RIA, and Section V.C of the preamble to the final rule and the Final Non-EGU Sectors TSD.

[5] A February 28, 2022 memorandum, titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*, documents the analytical framework used to identify industries and emissions unit types included in the proposed FIP. The memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.

[6] To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP. The TSD is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.

**Table ES-1. Summary of Non-EGU Industries, Emissions Unit Types, Form of Final Emissions Limits, and Final Emissions Limits**

| Industry | Emissions Unit Type | Form of Final Emissions Limits | Final Emissions Limits |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engines | Grams per horsepower per hours (g/hp-hr) | Four Stroke Rich Burn: 1.0 g/hp-hr<br>Four Stroke Lean Burn: 1.5 g/hp-hr<br>Two Stroke Lean Burn: 3.0 g/hp-hr |
| Cement and Concrete Product Manufacturing | Kilns | Pounds per ton (lbs/ton) of clinker | Long Wet: 4.0 lb/ton<br>Long Dry: 3.0 lb/ton<br>Preheater: 3.8 lb/ton<br>Precalciner: 2.3 lb/ton<br>Preheater/Precalciner: 2.8 lb/ton |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | lbs/mmBtu[a] | Test and set limit based on installation of Low-NOx Burners |
| Glass and Glass Product Manufacturing | Furnaces | lbs/ton glass produced | Container Glass Furnace: 4.0 lb/ton<br>Pressed/Blown Glass Furnace: 4.0 lb/ton<br>Fiberglass Furnace: 4.0 lb/ton<br>Flat Glass Furnace: 9.2 lb/ton |
| Iron and Steel Mills and Ferroalloy Manufacturing<br>Metal Ore Mining<br>Basic Chemical Manufacturing<br>Petroleum and Coal Products Manufacturing<br>Pulp, Paper, and Paperboard Mills | Boilers | lbs/mmBtu[a] | Coal: 0.20 lb/mmBtu<br>Residual Oil: 0.20 lb/mmBtu<br>Distillate Oil: 0.12 lb/mmBtu<br>Natural Gas: 0.08 lb/mmBtu |
| Solid Waste Combustors and Incinerators | Combustors or Incinerators | ppmvd on a 24-hour averaging period and ppmvd on a 30-day averaging period | 110 ppmvd on a 24-hour averaging period<br>105 ppmvd on a 30-day averaging period |

[a] Heat input limit.

For the final rule, using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB),[7] the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final*

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

*Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs* available in the docket.[8]

## ES.2 Baseline and Analysis Years

The final rule sets forth the requirements to eliminate states' significant contribution to downwind nonattainment or interference with maintenance of the 2015 ozone NAAQS. To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis years of 2023 and 2026, taking into account currently on-the-books Federal regulations, enforcement actions, state regulations, population, expected electricity demand growth, and where possible, economic growth. Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by this rule.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2023 through 2042. We focus on 2023 because it is by the 2023 ozone season, corresponding with the 2024 Moderate area attainment date, that significant contribution from upwind states' must be eliminated to the extent possible. In addition, impacts for 2026 are important because this ozone season corresponds with the 2027 Serious area attainment date, and it is by this ozone season that that additional requirements for NOx emissions reductions for EGUs and non-EGUs begin to apply for states whose upwind linkage to downwind receptors persists. Costs, benefits, and other impacts from compliance strategies are likely to persist beyond 2026, and the RIA provides costs and benefits through 2042.

## ES.3 Air Quality Modeling

The air quality modeling for the Transport FIP for the 2015 ozone NAAQS used a 2016-based modeling platform that included meteorology and base year emissions from 2016 and projected emissions for 2023 and 2026. The air quality modeling to support the analyses in this final RIA included photochemical model simulations for the 2016 base year and 2026 future

[8] The estimates prepared using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may be different than those estimated in this assessment. Further, the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

year. The model simulations included source apportionment modeling for the 2026 baseline to quantify the contributions to ozone from EGU and from non-EGU NOx emissions and the contributions to $PM_{2.5}$ from EGU emissions of NOx, $SO_2$, and directly emitted primary $PM_{2.5}$.[9] Source apportionment modeling for ozone and $PM_{2.5}$ was performed to provide contributions on a state-by-state basis. All of the air quality model simulations were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10. The CAMx nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 x 12 km.

The modeling results for 2016 and 2026, in conjunction with emissions data for the 2023 baseline, 2026 baseline, the final rule, and more and less stringent alternatives (regulatory control alternatives) in 2023 and 2026, were used to construct the air quality spatial fields that reflect the influence of emissions changes between the baseline and each regulatory control alternative. These spatial fields provide the air quality inputs to calculate health benefits for the Transport FIP for the 2015 ozone NAAQS and to inform the environment justice impact analysis in Chapter 7. The spatial fields were constructed based on a method that uses ozone and $PM_{2.5}$ contributions from emissions in individual states and state-level emissions reductions for each of the regulatory control alternatives coupled with baseline spatial fields of ozone and $PM_{2.5}$ concentrations. This method, as described in Chapter 3, was used most recently in the RIA for this proposal. In addition to the modeling to create spatial fields, we also performed air quality modeling to assess the parts per billion (ppb) impacts on projected ozone design values at monitoring sites nationwide in 2026 attributable to the EGU and non-EGU ozone season NOx emissions reductions projections from this final rule.

**ES.4 Control Strategies and Emissions Reductions**

The RIA analyzes emissions budgets for EGUs and ozone season emissions limits for non-EGUs, as well as a more and a less stringent alternative to the final rule. The more and less stringent alternatives differ from the Transport FIP for the 2015 ozone NAAQS in that they set

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[9] The ozone source apportionment modeling used for the proposed rule analyses is also used for this final rule analysis. In this regard, the contribution modeling is based on 2026 base case emissions that were developed for the proposed rule. At proposal, benefits associated with reductions in $PM_{2.5}$ concentrations were derived based on Benefit per Ton estimates for EGUs. For this final rule, we performed source apportionment modeling for $PM_{2.5}$ using the same 2026 emissions inventory that was used as input to the ozone source apportionment modeling.

different EGU $NO_X$ ozone season emission budgets and different dates for compliance with unit-specific emission limits for the affected EGUs and estimate different control technologies for some emissions units for the affected non-EGUs. Table ES-2. below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs. While the EGUs are required to comply with emissions budgets in 2023, tightening in 2026 for some states, along with a backstop emission rate for coal units, Table ES-2 also describes exogenously imposed compliance assumptions (i.e., control strategies) in the power sector modeling for purposes of the analysis (e.g., installation of state-of-the-art combustion controls and fully operating SNCRs and SCRs). Other control strategies are endogenous to the EGU analysis, such as changes in the dispatch order of generators and installation of post-combustion controls.

For non-EGUs, to establish the emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. We assumed control technologies would be adopted for compliance with the limitations in this analysis. For the purposes of summarizing the results of the benefits and costs of these alternatives, the less stringent alternative for EGUs is presented with the less stringent alternative for non-EGUs. However, the cost, emissions, and energy impacts for the EGU and non-EGU alternatives are evaluated separately.

**Table ES-2. Regulatory Control Alternatives for EGUs and Non-EGUs**

| **Regulatory Control Alternative** | **$NO_X$ Controls Implemented for EGUs within IPM[a, b]** |
|---|---|
| Less Stringent Alternative | 1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season<br>2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season<br>3) In 2023 install state-of-the-art combustion controls[c]<br>4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls.[d] |
| Final Rule | (All Controls above and)<br>5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls. |
| More Stringent Alternative | (Controls 1 – 5 above and)<br>6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire. |

| Regulatory Control Alternative | $NO_X$ Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance |
|---|---|
| Less Stringent Alternative | 1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio<br>2) Kilns in Cement and Cement Product Manufacturing – install SNCR<br>3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NOx burners (LNB)<br>4) Furnaces in Glass and Glass Product Manufacturing – install LNB<br>5) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install SNCR<br>6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN™ and SNCR[e] |
| Final Rule | (Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below)<br>7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install *Layered Combustion, non-selective catalytic reduction (NSCR), or SCR*<br>8) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)* |
| More Stringent Alternative | (Controls 3, 6, 7 above, plus changes in assumed controls noted below)<br>9) Kilns in Cement and Cement Product Manufacturing – install *SCR*<br>10) Furnaces in Glass and Glass Product Manufacturing – install *SCR*<br>11) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (natural gas-fired only)* |

[a] 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.
[b] NOx mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.
[c] The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occurring prior to 2026.
[d] For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas units greater than 100 MW that have historically emitted at least 150 tons of $NO_X$ per ozone season. The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies. The 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.
[e] Covanta has developed a proprietary low NOx combustion system (LN™) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

For 2023, total ozone season NOx emissions reductions of 10,000 tons are from EGUs; for 2026 total ozone season NOx emissions reductions of 70,000 tons are from EGUs and non-EGUs, and for 2030 total ozone season NOx emissions reductions of 79,000 tons are from EGUs and non-EGUs.

*ES.4.1 EGUs*

For the $NO_X$ controls for EGUs identified in Table ES-2, under the final rule and the less stringent and more stringent alternatives, 232 EGUs not already doing so in 2019 are assumed to fully operate existing SCRs. Under the final rule and the less stringent and more stringent alternatives, 39 units are assumed to fully operate existing SNCRs. Under the final rule and the less stringent and more stringent alternatives, 9 units are assumed to install state-of-the-art combustion controls. The book-life of the new combustion controls is assumed to be 15 years.

By 2030 the final rule is projected to result in an additional 14 GW of coal retirements nationwide relative to the baseline, constituting a reduction of 13 percent of national coal capacity, partially reflecting some earlier retirements under the rule relative to the baseline. Additionally, the rule is projected to incentivize an incremental 8 GW of SCR retrofit at coal plants. The rule is also projected to result in an incremental 3 GW of renewable capacity additions in 2025, consisting primarily of solar capacity builds. These builds reflect early action or builds that would otherwise have occurred later in the forecast period.

Table ES-3. shows the ozone season $NO_X$ emissions reductions expected from the final rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035, and 2042. In addition, Table ES-3 also shows the annual $NO_X$, $SO_2$, $PM_{2.5}$, and $CO_2$ emissions reductions expected from the final rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035, and 2042.[10] Under the more stringent alternative, the modeling projects a higher ratio of SCR retrofits to retirements, resulting in higher emissions projected under this alternative in later years.

**Table ES-3. EGU Ozone Season $NO_X$ Emissions Changes and Annual Emissions Changes for $NO_X$, $SO_2$, $PM_{2.5}$, and $CO_2$ for the Regulatory Control Alternatives from 2023 – 2042[11]**

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **2023** | | | |
| NOx (ozone season) | 10,000 | 10,000 | 10,000 |
| NOx (annual) | 15,000 | 15,000 | 15,000 |
| $SO_2$ (annual) | 1,000 | 3,000 | 1,000 |
| $CO_2$ (annual, thousand metric) | - | - | - |

[10] EGU results reflect IPM outputs for model run years (2023, 2025, 2028, 2030, 2035, 2040, and 2045). All other years are linearly interpolated.
[11] This analysis is limited to the geographically contiguous lower 48 states.

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| $PM_{2.5}$ (annual) | - | - | - |
| **2024** | | | |
| NOx (ozone season) | 21,000 | 10,000 | 33,000 |
| NOx (annual) | 25,000 | 15,000 | 57,000 |
| $SO_2$ (annual) | 19,000 | 5,000 | 59,000 |
| $CO_2$ (annual, thousand metric) | 10,000 | 4,000 | 20,000 |
| $PM_{2.5}$ (annual) | 1,000 | - | 1,000 |
| **2025** | | | |
| NOx (ozone season) | 32,000 | 10,000 | 56,000 |
| NOx (annual) | 35,000 | 15,000 | 99,000 |
| $SO_2$ (annual) | 38,000 | 7,000 | 118,000 |
| $CO_2$ (annual, thousand metric) | 21,000 | 8,000 | 40,000 |
| $PM_{2.5}$ (annual) | 2,000 | 1,000 | 2,000 |
| **2026** | | | |
| NOx (ozone season) | 25,000 | 8,000 | 49,000 |
| NOx (annual) | 29,000 | 12,000 | 88,000 |
| $SO_2$ (annual) | 29,000 | 5,000 | 104,000 |
| $CO_2$ (annual, thousand metric) | 16,000 | 6,000 | 34,000 |
| $PM_{2.5}$ (annual) | 1,000 | - | 2,000 |
| **2027** | | | |
| NOx (ozone season) | 19,000 | 6,000 | 43,000 |
| NOx (annual) | 22,000 | 9,000 | 78,000 |
| $SO_2$ (annual) | 21,000 | 4,000 | 91,000 |
| $CO_2$ (annual, thousand metric) | 10,000 | 3,000 | 28,000 |
| $PM_{2.5}$ (annual) | 1,000 | - | 2,000 |
| **2030** | | | |
| NOx (ozone season) | 34,000 | 33,000 | 31,000 |
| NOx (annual) | 62,000 | 59,000 | 50,000 |
| $SO_2$ (annual) | 93,000 | 98,000 | 51,000 |
| $CO_2$ (annual, thousand metric) | 26,000 | 23,000 | 8,000 |
| $PM_{2.5}$ (annual) | 1,000 | 1,000 | - |
| **2035** | | | |
| NOx (ozone season) | 29,000 | 30,000 | 27,000 |
| NOx (annual) | 46,000 | 46,000 | 41,000 |
| $SO_2$ (annual) | 21,000 | 19,000 | 15,000 |
| $CO_2$ (annual, thousand metric) | 16,000 | 15,000 | 8,000 |
| $PM_{2.5}$ (annual) | 1,000 | 1,000 | - |
| **2042** | | | |
| NOx (ozone season) | 22,000 | 22,000 | 22,000 |
| NOx (annual) | 23,000 | 22,000 | 21,000 |
| $SO_2$ (annual) | 15,000 | 15,000 | 7,000 |
| $CO_2$ (annual, thousand metric) | 9,000 | 8,000 | 4,000 |
| $PM_{2.5}$ (annual) | - | - | - |

Emissions changes for $NO_x$, $SO_2$, and $PM_{2.5}$ are in tons.

The Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA) includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the U.S. generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity. We include an appendix to Chapter 4 to describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline to account for the potential effects of the IRA of 2022 on the power sector costs, emission reductions, and other impacts from this final rule.

*ES.4.2 Non-EGUs*

Table ES-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 20 states subject to the rule in 2026, along with the estimated ozone season reductions for the final rule and the less and more stringent alternatives for 2026.[12] The EPA did not estimate emissions reductions of $SO_2$, $PM_{2.5}$, $CO_2$ and other pollutants that may be associated with controls on non-EGU emissions units; based on the estimated emissions reductions of NOx and typical relationships between NOx and these other pollutants, there are likely to be reductions of those additional pollutants. For the final rule, the EPA prepared an assessment summarized in the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* and the memorandum includes estimated emissions reductions by state for the rule. Table ES-5 below shows the industries, emissions unit types, assumed control technology that meets the final emissions limits and the estimated number of emissions units expected to install each control (Table ES-1 above summarizes the industries, emissions unit types, and assumed controls for the final rule). For additional results for 2026 – including estimated emissions reductions and costs by state and estimated emissions reductions and costs by state and industry – see the above cited memo. The analysis in the RIA assumes that the estimated reductions in 2026 for non-EGUs will be the same in later years.

[12] EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. The analysis assumes that the 2019 emissions from the emissions units will be the same in 2026 and later years.

**Table ES-4. Ozone Season NOx Emissions and Emissions Reductions (tons) for the Final Rule and the Less and More Stringent Alternatives for Non-EGUs in 2026**

| State | 2019 Ozone Season Emissions[a] | Final Rule – Ozone Season NOx Reductions | Less Stringent – Ozone Season NOx Reductions | More Stringent – Ozone Season NOx Reductions |
|---|---|---|---|---|
| AR | 8,790 | 1,546 | 457 | 1,690 |
| CA | 16,562 | 1,600 | 1,432 | 4,346 |
| IL | 15,821 | 2,311 | 751 | 2,991 |
| IN | 16,673 | 1,976 | 1,352 | 3,428 |
| KY | 10,134 | 2,665 | 583 | 3,120 |
| LA | 40,954 | 7,142 | 1,869 | 7,687 |
| MD | 2,818 | 157 | 147 | 1,145 |
| MI | 20,576 | 2,985 | 760 | 5,087 |
| MO | 11,237 | 2,065 | 579 | 4,716 |
| MS | 9,763 | 2,499 | 507 | 2,650 |
| NJ | 2,078 | 242 | 242 | 258 |
| NV | 2,544 | 0 | 0 | 0 |
| NY | 5,363 | 958 | 726 | 1,447 |
| OH | 18,000 | 3,105 | 1,031 | 4,006 |
| OK | 26,786 | 4,388 | 1,376 | 5,276 |
| PA | 14,919 | 2,184 | 1,656 | 4,550 |
| TX | 61,099 | 4,691 | 1,880 | 9,963 |
| UT | 4,232 | 252 | 52 | 615 |
| VA | 7,757 | 2,200 | 978 | 2,652 |
| WV | 6,318 | 1,649 | 408 | 2,100 |
| **Totals** | **302,425** | **44,616** | **16,786** | **67,728** |

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

**Table ES-5. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits, Estimated Number of Control Installations**

| Industry/Industries | Emissions Unit Type | Assumed Control Technologies that Meet Final Emissions Limits | Estimated Number of Units Per Assumed Control |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engines | NSCR or Layered Combustion (Reciprocating) | 323 |
| | | Layered Combustion (2-cycle Lean Burn) | 394 |
| | | SCR (4-cycle Lean Burn) | 158 |
| | | NSCR (4-cycle Rich Burn) | 30 |
| Cement and Concrete Product Manufacturing | Kiln | SNCR | 16 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | LNB | 19 |
| Glass and Glass Product Manufacturing | Furnaces | LNB | 61 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Boilers | LNB + FGR (Gas, No Coal or Oil) | 151 |
| Metal Ore Mining | | SCR (Any Coal, Any Oil) | 15 |
| Basic Chemical Manufacturing | | | |
| Petroleum and Coal Products Manufacturing | | | |
| Pulp, Paper, and Paperboard Mills | | | |
| Solid Waste Combustors and Incinerators[a] | Combustors or Incinerators | ANSCR | 57 |
| | | LN™ and SNCR | 4 |
| | | **Total** | **1,228** |

[a] Twelve MWCs have existing controls, and we estimated these units will use more reagent in those controls to meet the final emissions limits.

## ES.5 Costs

Table ES-6 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates for EGUs and non-EGUs for the final rule and the less and more stringent alternatives. The compliance cost estimate for EGUs is the incremental electricity generation system cost associated with complying with the emission budgets and backstop emission rate. Chapter 4, Section 4.3 describes the modeling and methodology used to estimate EGU costs and Section 4.5 presents results, including impacts on fuel use, prices, and generation mix. The compliance cost estimate for non-EGUs is the engineering cost of installing pollution controls. Chapter 4, Section 4.4 describes the methodology used to estimate non-EGU costs and Section 4.5 presents results, including average cost-per-ton estimates across industries and assumed technologies. These compliance cost estimates are used as a proxy for the social cost of the rule. We present the PV of the costs over the twenty-year period 2023 to 2042. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis.

**Table ES-6. Total National Compliance Cost Estimates (millions of 2016$) for the Final Rule and the Less and More Stringent Alternatives**

| | Final Rule | | Less Stringent Alternative | | More Stringent Alternative | |
|---|---|---|---|---|---|---|
| | **3 Percent** | **7 Percent** | **3 Percent** | **7 Percent** | **3 Percent** | **7 Percent** |
| Present Value EGU 2023-2042 | $6,800 | $3,900 | $6,800 | $3,900 | $9,500 | $6,500 |
| Present Value Non-EGU 2026-2042 | $6,700 | $4,300 | $1,700 | $1,100 | $15,000 | $9,500 |
| **Present Value Total 2023-2042** | **$13,000** | **$8,200** | **$8,400** | **$5,000** | **$24,000** | **$16,000** |
| EGU Equivalent Annualized Value | $460 | $370 | $450 | $370 | $640 | $620 |
| Non-EGU Equivalent Annualized Value | $450 | $400 | $110 | $100 | $1,000 | $900 |
| **Total Equivalent Annualized Value** | **$910** | **$770** | **$570** | **$470** | **$1,600** | **$1,500** |

Note: Values have been rounded to two significant figures

## ES.6 Benefits

### *ES.6.1 Health Benefits Estimates*

The final rule is expected to reduce ozone season and annual $NO_X$ emissions. In the presence of sunlight, $NO_X$ and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing $NO_X$ emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. In addition to NOx, the rule is also expected to reduce emissions of direct $PM_{2.5}$ and $SO_2$ throughout the year from EGUs. Because $NO_X$ and $SO_2$ are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.

In this RIA for the Transport FIP for the 2015 ozone NAAQS, the EPA quantifies benefits of changes in ozone and $PM_{2.5}$ concentrations. The health effects and effect estimates, and how they were selected, are described in the technical support document for the 2022 PM NAAQS Reconsideration Proposal RIA titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*. The approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in Chapter 5.

Table ES-7 and Table ES-8 report the estimated economic value of avoided premature deaths and illness in 2023 and 2026 relative to the baseline along with the 95% confidence interval. The number of reduced estimated deaths and illnesses from the final rule and more and less stringent alternatives is calculated from the sum of individual reduced mortality and illness risk across the population. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates.

**Table ES-7. Estimated Discounted Monetized Value of Avoided Ozone-Related Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2023 (95% Confidence Interval; millions of 2016$)[a,b]**

| Disc. Rate | Pollutant | Final Rule | | | More Stringent Alternative | | | Less Stringent Alternative | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 3% | Ozone Benefits | $100 ($27 to $220)[c] | *and* | $820 ($91 to $2,100)[d] | $110 ($28 to $230)[c] | *and* | $840 ($94 to $2,200)[d] | $100 ($27 to $220)[c] | *and* | $810 ($91 to $2,100)[d] |
| 7% | Ozone Benefits | $93 ($17 to 210)[c] | *and* | $730 ($75 to $1,900)[d] | $96 ($18 to $210)[c] | *and* | $750 ($77 to $2,000)[d] | $93 ($17 to $210)[c] | *and* | $730 ($75 to $1,900)[d] |

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NOx for the ozone season for EGUs in 2023. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

**Table ES-8. Estimated Discounted Monetized Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2026 (95% Confidence Interval; millions of 2016$)[a,b]**

| Disc Rate | Pollutant | Final Rule | | | More Stringent Alternative | | | Less Stringent Alternative | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 3% | Ozone Benefits | $1,100 ($280 to $2,400)[c] | *and* | $9,400 ($1,000 to $25,000)[d] | $1,900 (470 to $4,000)[c] | *and* | $15,000 ($1,700 to $40,000)[d] | $420 ($110 to $900)[c] | *and* | $3,400 ($380 to $8,900)[d] |
| | PM Benefits | $2,000 ($220 to $5,300) | *and* | $4,400 ($430 to $12,000) | $6,400 ($690 to $17,000) | *and* | $14,000 ($1,300 to $37,000) | $530 ($57 to $1,400) | *and* | $1,100 ($110 to $3,100) |
| | Ozone plus PM Benefits | $3,200 ($500 to $7,700)[c] | *and* | $14,000 ($1,500 to $36,000)[d] | $8,300 ($1,200 to $21,000)[c] | *and* | $29,000 ($3,000 to $77,000)[d] | $950 ($160 to $2,300)[c] | *and* | $4,600 ($490 to $12,000)[d] |
| 7% | Ozone Benefits | $1,000 ($180 to $2,300)[c] | *and* | $8,400 ($850 to $22,000)[d] | $1,700 ($300 to $3,800)[c] | *and* | $14,000 ($1,400 to $36,000)[d] | $380 ($68 to $850)[c] | *and* | $3,100 ($310 to $8,100)[d] |
| | PM Benefits | $1,800 ($190 to $4,700) | *and* | $3,900 ($380 to $11,000) | $5,800 ($600 to $15,000) | *and* | $12,000 ($1,200 to $33,000) | 470 ($50 to $1,200) | *and* | $1,000 ($100 to $2,800) |
| | Ozone plus PM Benefits | $2,800 ($370 to $7,000)[c] | *and* | $12,000 ($1,200 to $33,000)[d] | $7,500 ($910 to $19,000)[c] | *and* | $26,000 ($2,600 to $69,000)[d] | $850 ($120 to $2,100)[c] | *and* | $4,100 ($410 to $11,000)[d] |

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NOx for the ozone season and annual changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

*ES.6.2 Climate Benefits*

Elevated concentrations of GHGs in the atmosphere have been warming the planet, leading to changes in the Earth's climate including changes in the frequency and intensity of heat waves, precipitation, and extreme weather events, rising seas, and retreating snow and ice. The well-documented atmospheric changes due to anthropogenic GHG emissions are changing the climate at a pace and in a way that threatens human health, society, and the natural environment. Climate change touches nearly every aspect of public welfare in the U.S. with resulting economic costs, including: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization).

There will be important climate benefits associated with the $CO_2$ emissions reductions expected from this final rule. Climate benefits from reducing emissions of $CO_2$ can be monetized using estimates of the social cost of carbon (SC-$CO_2$). See Chapter 5, Section 5.2 for more discussion of the approach to monetization of the climate benefits associated with this rule.

*ES.6.3 Total Monetized Human Health and Climate Benefits*

Tables ES-9 through ES-11 below present the total monetized health and climate benefits for the final rule and the less and more stringent alternatives for 2023, 2026, and 2030.

**Table ES-9. Combined Monetized Health and Climate Benefits for the Final Rule and Less and More Stringent Alternatives for 2023 (millions of 2016$)**

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) 3% | 7% | Climate Benefits Only[a] |
|---|---|---|---|
| Final Rule | | | |
| 5% (average) | $100 and $820 | $94 and $730 | $1 |
| 3% (average) | $100 and $820 | $98 and $740 | $5 |
| 2.5% (average) | $110 and $820 | $100 and $740 | $7 |
| 3% (95th percentile) | $110 and $830 | $110 and $750 | $14 |
| Less Stringent Alternative | | | |
| 5% (average) | $100 and $810 | $94 and $730 | $1 |
| 3% (average) | $100 and $820 | $97 and $730 | $4 |
| 2.5% (average) | $110 and $820 | $99 and $730 | $6 |
| 3% (95th percentile) | $110 and $830 | $100 and $740 | $12 |
| More Stringent Alternative | | | |
| 5% (average) | $110 and $840 | $97 and $750 | $1 |
| 3% (average) | $110 and $840 | $100 and $760 | $5 |
| 2.5% (average) | $120 and $850 | $100 and $760 | $7 |
| 3% (95th percentile) | $120 and $850 | $110 and $770 | $14 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon (SC-$CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).

**Table ES-10. Combined Monetized Health and Climate Benefits for the Final Rule and Less and More Stringent Alternatives for 2026 (millions of 2016$)**

| $SC\text{-}CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) | | Climate Benefits Only[a] |
|---|---|---|---|
| | 3% | 7% | |
| Final Rule | | | |
| 5% (average) | $3,500 and $14,000 | $3,100 and $13,000 | $340 |
| 3% (average) | $4,300 and $15,000 | $3,900 and $13,000 | $1,100 |
| 2.5% (average) | $4,800 and $15,000 | $4,400 and $14,000 | $1,600 |
| 3% (95th percentile) | $6,600 and $17,000 | $6,200 and $16,000 | $3,400 |
| Less Stringent Alternative | | | |
| 5% (average) | $1,100 and $4,700 | $980 and $4,200 | $130 |
| 3% (average) | $1,400 and $5,000 | $1,300 and $4,500 | $420 |
| 2.5% (average) | $1,600 and $5,200 | $1,500 and $4,700 | $620 |
| 3% (95$^{th}$ percentile) | $2,200 and $5,800 | $2,100 and $5,400 | $1,300 |
| More Stringent Alternative | | | |
| 5% (average) | $8,900 and $30,000 | $13,000 and $27,000 | $640 |
| 3% (average) | $10,000 and $31,000 | $14,000 and $28,000 | $2,100 |
| 2.5% (average) | $11,000 and $32,000 | $15,000 and $29,000 | $3,100 |
| 3% (95$^{th}$ percentile) | $15,000 and $35,000 | $18,000 and $32,000 | $6,400 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95$^{th}$ percentile at 3 percent discount rate).

**Table ES-11. Combined Monetized Health and Climate Benefits for the Final Rule and Less and More Stringent Alternatives for 2030 (millions of 2016$)**

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) | | Climate Benefits Only[a] |
|---|---|---|---|
| | 3% | 7% | |
| Final Rule | | | |
| 5% (average) | $3,900 and $15,000 | $3,500 and $14,000 | $470 |
| 3% (average) | $4,900 and $16,000 | $4,500 and $15,000 | $1,500 |
| 2.5% (average) | $5,600 and $17,000 | $5,200 and $15,000 | $2,200 |
| 3% (95th percentile) | $8,000 and $19,000 | $7,600 and $18,000 | $4,600 |
| Less Stringent Alternative | | | |
| 5% (average) | $1,400 and $5,300 | $1,300 and $4,800 | $420 |
| 3% (average) | $2,300 and $6,200 | $2,300 and $5,700 | $1,300 |
| 2.5% (average) | $3,000 and $6,800 | $2,900 and $6,300 | $2,000 |
| 3% (95th percentile) | $5,100 and $8,900 | $5,000 and $8,400 | $4,100 |
| More Stringent Alternative | | | |
| 5% (average) | $9,200 and $31,000 | $8,300 and $28,000 | $150 |
| 3% (average) | $9,500 and $31,000 | $8,600 and $28,000 | $480 |
| 2.5% (average) | $9,700 and $32,000 | $8,800 and $28,000 | $700 |
| 3% (95th percentile) | $10,000 and $32,000 | $9,500 and $29,000 | $1,400 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon (SC-$CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).

### *ES.6.4 Additional Unquantified Benefits*

Data, time, and resource limitations prevented the EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to $NO_2$ and $SO_2$ (independent of the role $NO_2$ and $SO_2$ play as precursors to ozone and $PM_{2.5}$), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to ozone, $PM_{2.5}$, $NO_2$ or $SO_2$. For a qualitative description of these and water quality benefits, please see Chapter 5, section 5.4.

## ES.7 Environmental Justice Impacts

Environmental justice (EJ) concerns for each rulemaking are unique and should be considered on a case-by-case basis, and the EPA's EJ Technical Guidance[13] states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?"

To address these questions, the EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures and impacts. For the rule, we quantitatively evaluate 1) the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by this rule but not modeled here (Chapter 7, Section 7.3) and 2) the distribution of ozone and $PM_{2.5}$ concentrations in the baseline and changes due to the final rulemaking across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation (Chapter 7, Section 7.4). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors, in this case such as, local $NO_2$ emitted from sources affected by the regulatory action for certain population groups of concern (Chapter 7, Section 7.3). The baseline demographic proximity analyses suggest that larger percentages of Hispanics, African Americans, people below the poverty level, people with less

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

educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Relating these results to question 1, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., $NO_2$) for certain population groups of concern in the baseline. However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

Because the pollution impacts that are the focus of this rule are often substantially downwind from affected facilities, ozone and $PM_{2.5}$ exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of this rulemaking. The baseline ozone and $PM_{2.5}$ exposure analyses respond to question 1 from the EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory action (Chapter 7, Section 7.4). Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indians may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how post-policy regulatory alternatives of this final rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from the EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. We infer that disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with this rulemaking across population demographic subgroups, relative to baseline disparities (question 2). Also, due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration, compared to the baseline (question 3). Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in many areas, including in ozone nonattainment areas, and thus mitigate some pre-existing health risks across all populations evaluated.

**ES.8 Results of Benefit-Cost Analysis**

Below we present the annual costs and benefits estimates for 2023, 2026, and 2030, respectively. This analysis uses annual compliance costs reported above as a proxy for social costs. The estimated annual compliance costs to implement the rule, as described in this RIA, are approximately $57 million in 2023 and $570 million in 2026 (2016$).

The estimated monetized health benefits from reduced ozone and $PM_{2.5}$ concentrations from implementation of the rule are approximately $100 and $820 million in 2023 (2016$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately $5 million in 2023 (2016$, based on a real discount rate of 3 percent). For 2026, the estimated monetized health benefits from implementation of the rule are approximately $3,200 and $14,000 million (2016$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately $1,100 million in 2026 (2016$, based on a real discount rate of 3 percent).

The EPA calculates the monetized net benefits of the rule by subtracting the estimated monetized compliance costs from the estimated monetized health and climate benefits in 2023, 2026, and 2030. The benefits include those to public health associated with reductions in ozone and $PM_{2.5}$ concentrations, as well as those to climate associated with reductions in GHG emissions. The annual monetized net benefits of the rule in 2023 (in 2016$) are approximately $48 and $760 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2026 are approximately $3,700 and $14,000 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2030 are approximately $3,600 and $15,000 million using a 3 percent real discount rate. Table ES-12 presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the less and more stringent alternatives for 2023. Table ES-13. presents a summary of these impacts for the rule and the less and more stringent alternatives for 2026. Table ES-14 presents a summary of these impacts for the rule and the less and more stringent alternatives for 2030. These results present an incomplete overview of the effects of the rule because important categories of benefits–- including benefits from reducing other types of air pollutants, and water pollution – were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than these tables reflect.

**Table ES-12. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016$)[a,b]**

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits[c]** | $100 and $820 | $100 and $810 | $110 and $840 |
| **Climate Benefits** | $5 | $4 | $5 |
| **Total Benefits** | $100 and $820 | $100 and $820 | $110 and $840 |
| **Costs[d]** | $57 | $56 | $49 |
| **Net Benefits** | **$48 and $760** | **$48 and $760** | **$66 and $800** |

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

**Table ES-13. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016$)[a,b]**

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits[c]** | $3,200 and $14,000 | $950 and $4,600 | $8,300 and $29,000 |
| **Climate Benefits** | $1,100 | $420 | $2,100 |
| **Total Benefits** | $4,300 and $15,000 | $1,400 and $5,000 | $10,000 and $31,000 |
| **Costs[d]** | $570 | $110 | $2,100 |
| **Net Benefits** | **$3,700 and $14,000** | **$1,300 and $4,900** | **$8,300 and $29,000** |

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

**Table ES-14. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016$)[a,b]**

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits[c]** | $3,400 and $15,000 | $1,000 and $4,900 | $9,000 and $31,000 |
| **Climate Benefits** | $1,500 | $1,300 | $500 |
| **Total Benefits** | $4,900 and $16,000 | $2,300 and $6,200 | $9,500 and $31,000 |
| **Costs[d]** | $1,300 | $920 | $2,100 |
| **Net Benefits** | **$3,600 and $15,000** | **$1,400 and $5,300** | **$7,400 and $29,000** |

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

As part of fulfilling analytical guidance with respect to E.O. 12866, the EPA presents estimates of the present value (PV) of the monetized benefits and costs over the twenty-year period 2023 to 2042. To calculate the present value of the social net-benefits of the final rule, annual benefits and costs are discounted to 2023 at 3 percent and 7 discount rates as directed by OMB's Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA. Note that EGU costs reported in this RIA for years not explicitly modeled are mapped to modeled years. 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. Non-EGU costs are assumed to be constant throughout the time horizon.

The health benefits analysis quantifies changes in ozone concentrations in 2023 and changes in ozone and $PM_{2.5}$ in 2026 for each of the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative). Analyses were also run for each year between 2023 and 2042, using the air quality model surfaces, but accounting for the change in population size in each year, income growth, and baseline mortality incidence rates at five-year increments. However, because of uncertainties associated with baseline air quality projections beyond 2026, annual health benefits beyond 2026 are based on 2026 air quality changes. The 2023 ozone concentration changes were assumed through 2025 and the 2026 ozone and $PM_{2.5}$ concentration changes were assumed until 2042. Finally, climate benefits are mapped using the same model year mapping from IPM applied for the EGU cost analysis. GHG emissions reductions are multiplied by year specific social cost of carbon values.

For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016$ and discounted to 2023, is $200,000 million when using a 3 percent discount rate and $140,000 million when using a 7 percent discount rate. The EAV is $13,000 million per year when using a 3 percent discount rate and $12,000 million when using a 7 percent discount rate. The comparison of benefits and costs in PV and EAV terms for the final rule can be found in Table ES-15. Estimates in the table are presented as rounded values.

**Table ES-15. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016$, discounted to 2023)**

| | Health Benefits | | Climate Benefits | Cost | | Net Benefits | |
|---|---|---|---|---|---|---|---|
| | **3%** | **7%** | **3%** | **3%** | **7%** | **3%** | **7%** |
| 2023 | $820 | $730 | $5 | $57 | $57 | $770 | $680 |
| 2024 | $810 | $700 | $1,000 | ($5) | ($5) | $1,300 | $1,200 |
| 2025 | $8,600 | $7,100 | $1,000 | ($5) | ($4) | $9,600 | $8,100 |
| 2026 | $13,000 | $10,000 | $1,000 | $520 | $460 | $13,000 | $10,000 |
| 2027 | $13,000 | $9,700 | $230 | $530 | $450 | $13,000 | $9,700 |
| 2028 | $12,000 | $8,900 | $230 | $510 | $420 | $12,000 | $8,700 |
| 2029 | $12,000 | $8,500 | $230 | $500 | $400 | $12,000 | $8,800 |
| 2030 | $12,000 | $8,200 | $1,200 | $1,000 | $800 | $12,000 | $8,600 |
| 2031 | $12,000 | $7,800 | $1,200 | $1,000 | $740 | $12,000 | $8,200 |
| 2032 | $12,000 | $7,500 | $740 | $1,100 | $760 | $12,000 | $7,700 |
| 2033 | $11,000 | $7,000 | $730 | $1,000 | $710 | $11,000 | $7,200 |
| 2034 | $11,000 | $6,700 | $720 | $1,000 | $660 | $11,000 | $6,900 |
| 2035 | $11,000 | $6,400 | $710 | $970 | $620 | $11,000 | $6,500 |
| 2036 | $11,000 | $6,100 | $700 | $950 | $580 | $11,000 | $6,300 |
| 2037 | $11,000 | $5,800 | $690 | $920 | $540 | $11,000 | $6,000 |
| 2038 | $11,000 | $5,400 | $860 | $890 | $500 | $11,000 | $5,700 |
| 2039 | $10,000 | $5,100 | $850 | $870 | $470 | $9,900 | $5,400 |
| 2040 | $10,000 | $4,900 | $830 | $840 | $440 | $10,000 | $5,300 |
| 2041 | $10,000 | $4,600 | $820 | $820 | $410 | $9,900 | $4,900 |
| 2042 | $10,000 | $4,400 | $810 | $790 | $380 | $9,800 | $4,600 |
| **PV 2023-2042** | **$200,000** | **$130,000** | **$15,000** | **$14,000** | **$9,400** | **$200,000** | **$140,000** |
| **EAV 2023-2042** | **$13,000** | **$12,000** | **$970** | **$910** | **$770** | **$13,000** | **$12,000** |

## CHAPTER 1: INTRODUCTION AND BACKGROUND

### Overview

In this final rule, the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS), the EPA sets implementation mechanisms to achieve enforceable emissions reductions required to eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in other states. The initial phase of emissions reductions will begin in the 2023 ozone season with further emissions reductions being required in later years.[14]

The EPA is promulgating new or revised FIPs for 23 states. For 22 states the FIPs include new $NO_X$ ozone season emission budgets for EGU sources, with implementation of these emission budgets beginning in the 2023 ozone season.[15] The EPA is expanding the CSAPR $NO_X$ Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require electric generating units (EGUs) within the borders of the 22 states to participate in a revised version of the CSAPR $NO_X$ Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program under FIPs or SIPs remain in the program, with revised provisions beginning in the 2023 ozone season. The FIPs also require affected EGUs within the borders of seven states currently covered by the CSAPR $NO_X$ Ozone Season Group 2 Trading Program (the "Group 2 trading program") under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period. Lastly, the EPA is issuing new FIPs for three states not currently covered by any CSAPR $NO_X$ ozone season trading program (Minnesota, Nevada, and Utah).

[14] The 2015 ozone NAAQS is an 8-hour standard that was set at 70 parts per billion (ppb). See 80 FR 65291 (December 28, 2015).

[15] In 2023, the 22 states with EGU reduction requirements include AL, AR, IL, IN, KY, LA, MD, MI, MN, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, WV, and WI. There are no EGU reductions being required from California, which if included would make 23 states.

The FIPs that EPA is promulgating for 20 states include new $NO_X$ emissions limitations for non-electric generating unit (non-EGU) sources, with initial compliance dates for these emissions limitations beginning in 2026.[16]

Consistent with OMB Circular A-4 and the EPA's *Guidelines for Preparing Economic Analyses* (2010), this regulatory impact analysis (RIA) presents the benefits and costs of the final rule from 2023 through 2042. The estimated monetized benefits are those health benefits expected to arise from reduced ozone and $PM_{2.5}$ concentrations and the benefits from reductions in greenhouse gases. The estimated monetized costs for EGUs are the costs of installing and operating controls and other increased costs of producing electricity to comply with the revised version of the Group 3 trading program. The estimated monetized costs for non-EGUs are the costs of installing and operating controls to meet the ozone season NOx emissions limitations.[17] The estimated costs for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs. Unquantified benefits and costs are described qualitatively. The RIA also provides (i) estimates of other impacts of the rule including its effect on retail electricity prices and fuel production, (ii) an assessment of how expected compliance with the rule will affect concentrations at nonattainment and maintenance receptors, and (iii) an assessment of potential environmental justice concerns. This chapter contains background information relevant to the rule and an outline of the chapters of this RIA.

## 1.1 Background

Clean Air Act (CAA or the Act) section 110(a)(2)(D)(i)(I), which is also known as the "good neighbor provision," requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS. The statute vests states with the primary responsibility to address interstate emission transport through the development of good neighbor State Implementation Plans (SIPs), which are one component of larger SIP submittals typically required three years after the EPA

[16] In 2026, the 20 states with non-EGU reduction requirements include AR, CA, IL, IN, KY, LA, MD, MI, MS, MO, NV, NJ, NY, OH, OK, PA, TX, UT, VA, and WV.

[17] For non-EGUs, we prepared a memorandum for the final rule that summarizes the (i) industries affected, (ii) applicability criteria, (iii) final emissions limits, (iv) estimated emissions units, and (v) estimated emissions reductions and costs (the memorandum, titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs*, is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668.

promulgates a new or revised NAAQS. These larger SIPs are often referred to as "infrastructure" SIPs or iSIPs. *See* CAA section 110(a)(1) and (2).

The EPA originally published the Cross-State Air Pollution Rule (CSAPR) on August 8, 2011, to address interstate transport of ozone pollution under the 1997 ozone National Ambient Air Quality Standards (NAAQS).[18] On October 26, 2016, the EPA published the CSAPR Update, which finalized Federal Implementation Plans (FIPs) for 22 states that the EPA found failed to submit a complete good neighbor State Implementation Plan (SIP) (15 states)[19] or for which the EPA issued a final rule disapproving their good neighbor SIP (7 states).[20] The FIPs promulgated for these states included new electric generating unit (EGU) oxides of nitrogen ($NO_X$) ozone season emission budgets to reduce interstate transport for the 2008 ozone NAAQS.[21] These emissions budgets took effect in 2017 in order to assist downwind states with attainment of the 2008 ozone NAAQS by the 2018 Moderate area attainment date. The EPA acknowledged at the time that the FIPs promulgated for 21 of the 22 states only partially addressed good neighbor obligations under the 2008 ozone NAAQS.[22]

On March 31, 2021, the EPA promulgated the Revised CSAPR Update (RCU) in response to the United States Court of Appeals for the District of Columbia Circuit's (D.C. Circuit) September 13, 2019, remand of the CSAPR Update. The D.C. Circuit found that the CSAPR Update was unlawful to the extent it allowed those states to continue their significant contributions to downwind ozone problems beyond the statutory dates by which downwind states must demonstrate their attainment of the air quality standards. The RCU resolved 21 states' outstanding interstate ozone transport obligations with respect to the 2008 ozone NAAQS and established a new Group 3 ozone season emissions trading program for EGUs for twelve states.

[18] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.

[19] Alabama, Arkansas, Illinois, Iowa, Kansas, Maryland, Michigan, Mississippi, Missouri, New Jersey, Oklahoma, Pennsylvania, Tennessee, Virginia, and West Virginia.

[20] Indiana, Kentucky, Louisiana, New York, Ohio, Texas, and Wisconsin.

[21] The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb). See 73 FR 16436 (March 27, 2008).

[22] In the CSAPR Update, the EPA found that the finalized Tennessee emission budget fully addressed Tennessee's good neighbor obligation with respect to the 2008 ozone NAAQS. As such, the number of states included was reduced from 22 to 21 states.

As described in the preamble of this rule, to reduce interstate emission transport under the authority provided in CAA section 110(a)(2)(D)(i)(I) for the more protective 2015 ozone NAAQS, this rule further limits ozone season (May 1 through September 30) NOx emissions from EGUs in 22 states beginning in 2023 and non-EGUs in 20 states beginning in 2026 using the Interstate Transport Framework. The Interstate Transport Framework, the framework developed by the EPA in the original CSAPR, provides a 4-step process to address the requirements of the good neighbor provision for ground-level ozone and fine particulate matter ($PM_{2.5}$) NAAQS: (1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems (*i.e.*, here, a 1 percent contribution threshold); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, implementing the necessary emissions reductions through enforceable measures.

### *1.1.1 Role of Executive Orders in the Regulatory Impact Analysis*

Several statutes and executive orders apply to federal rulemakings. In accordance with Executive Orders 12866 and 13563 and the guidelines of OMB Circular A-4, the RIA analyzes the benefits and costs associated with emissions reductions for compliance with the rule. OMB Circular A-4 recommends analysis of one potential regulatory control alternative more stringent than the final rule and one less stringent than the final rule. This RIA evaluates the benefits, costs, and certain impacts of a more and a less stringent alternative to the selected alternative in this rule.

### *1.1.2 Alternatives Analyzed*

In response to OMB Circular A-4, this RIA analyzes the Transport FIP for the 2015 ozone NAAQS emission budgets for EGUs and ozone season emissions limits for non-EGUs, as well as a more and a less stringent alternative to the final rule. For EGUs, the Transport FIP for the 2015 ozone NAAQS requires EGUs in the 22 states to participate in the CSAPR $NO_X$ Ozone

Season Group 3 Trading Program created by the Revised CSAPR Update. For non-EGUs, the Transport FIP for the 2015 ozone NAAQS requires units subject to the rule to meet ozone season emissions limits.

The less stringent alternative differs from the Transport FIP for the 2015 ozone NAAQS in that it sets different EGU $NO_X$ ozone season emission budgets. The more stringent alternative differs from the Transport FIP for the 2015 ozone NAAQS in that it features different dates for compliance with unit-specific emission rates for the affected EGUs. The more and less stringent alternatives also estimate different control technologies for some emissions units for the affected non-EGUs under the assumption that they would be subject to different emission rates. Table 1-1 below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs.

For EGUs, one of the primary ways the final Transport FIP for the 2015 ozone NAAQS differs from the proposal is the compliance date for the backstop emission rate. At proposal, both the proposed rule and more stringent alternative imposed the backstop emission rate in 2026. The EPA continues to view the backstop emission rate as an important element of the rule to ensure the elimination of significant contribution as determined at Step 3 of the Interstate Transport Framework for all large coal units, and the rule therefore imposes this rate beginning in 2024 for units that already have SCR installed. However, in the final rule, to facilitate power sector transition planning and in response to concerns from commenters, the EPA is deferring the imposition of the backstop emissions rate for units that do not have SCR until the second ozone season following installation of the control or 2030 at the latest. The modeling of the final rule includes the backstop emission rate in the 2030 model run year and the more stringent alternative includes the backstop emission rate in the 2025 model run year (corresponding to 2026).

For the non-EGU industries, in the final rule we made some minor changes to the non-EGU emissions units covered, the applicability criteria, as well as provided for facility-wide emissions averaging for engines and for a low-use exemption to eliminate the need to install controls on low-use boilers; the changes make directly comparing the alternatives analyzed between proposal and this final rule challenging. Please see Section 1.2.1 below for a more detailed discussion of the changes made and Table 1-1 below for a summary of the alternatives analyzed in the final rule.

**Table 1-1. Regulatory Control Alternatives for EGUs and Non-EGUs**

| **Regulatory Control Alternative** | **$NO_X$ Controls Implemented for EGUs within IPM[a, b]** |
|---|---|
| Less Stringent Alternative | 1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season<br>2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season<br>3) In 2023 install state-of-the-art combustion controls[c]<br>4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls.[d] |
| Final Rule | (All Controls above and)<br>5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls. |
| More Stringent Alternative | (Controls 1 – 5 above and)<br>6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire. |
| **Regulatory Control Alternative** | **$NO_X$ Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance** |
| Less Stringent Alternative | 1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio<br>2) Kilns in Cement and Cement Product Manufacturing – install SNCR<br>3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NOx burners (LNB)<br>4) Furnaces in Glass and Glass Product Manufacturing – install LNB<br>5) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install SNCR<br>6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN™ and SNCR[e] |
| Final Rule | (Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below)<br>7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install *Layered Combustion, non-selective catalytic reduction (NSCR), or SCR*<br>8) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)* |
| More Stringent Alternative | (Controls 3, 6, 7 above, plus changes in assumed controls noted below)<br>9) Kilns in Cement and Cement Product Manufacturing – install *SCR*<br>10) Furnaces in Glass and Glass Product Manufacturing – install *SCR*<br>11) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (natural gas-fired only)* |

[a] 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

[b] NOx mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.
[c] The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occuring prior to 2026.
[d] For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas units greater than 100 MW that have historically emitted at least 150 tons of $NO_X$ per ozone season. The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies. The 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.
[e] Covanta has developed a proprietary low NOx combustion system (LN™) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

The illustrative emission budgets in this RIA represent EGU $NO_X$ ozone season emission budgets for each state beginning in 2023.[23] All three scenarios use emission budgets that were developed using the selected level of uniform control stringency represented by $1,800 per ton of $NO_X$ (2016$) in 2023 and $11,000 per ton of NOx (2016$) in 2026. The final rule and less-stringent alternative scenarios defer the backstop emission rate for existing coal EGUs lacking SCR controls in the 2030 run year,[24] while the more stringent alternative imposes the backstop emission rate on these units in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed by these years (2025 or 2030 depending on scenario) on all coal units within the 19-state region[25] that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units). Across all three scenarios, optimization of existing controls and installation of state-of-the-art combustion controls (which

[23] The budget setting process is described in section VI.B. of the preamble and in detail in the Ozone Transport Policy Analysis Final Rule Technical Support Document (TSD).
[24] 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
[25] For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas units greater than 100 MW that have historically emitted at least 150 tons of $NO_X$ per ozone season. The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies. The 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

reflect emission rate limits) is assumed in the 2023 run year (although the rule would not require state of the art combustion control installation until 2024).

The state emission budgets in this RIA are illustrative for several reasons. First, they reflect an estimate of the future budget based on the EPA's preset budget methodology throughout the analytic time frame of the analysis. However, as described in the preamble, the implemented state budget may be either the preset budget or the dynamic budget starting in 2026. Second, the budgets are illustrative as the utilized 2023 preset budgets reflect full implementation of existing control optimization and upgrade to state-of-the-art combustion control potential. However, the final rule state emission budgets and implementation allows the limited number of reductions related to state-of-the-art combustion controls to be realized up through 2024. Finally, the illustrative budgets reflected in this RIA reflect budgets derived using the EPA's data and engineering analysis up through October 2022. The preset budgets reflected in the final rule are slightly different in some cases due to new data or comment incorporation that occurred between October of 2022 and January 2023. The Agency conducted additional sensitivity analysis using IPM demonstrating that the substituting in the final preset state emission budgets instead of the illustrative ones modeled made no significant difference in the cost implications described in the body of the RIA.

For non-EGUs, the less stringent alternative assumes less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills relative to the final rule. The more stringent alternative assumes more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass and Glass Products Manufacturing, and the natural gas fired boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills relative to the final rule. See Section V.C. of the preamble for details on the emissions limits in the final rule.

### *1.1.3 The Need for Regulation*

OMB Circular A-4 indicates that one of the reasons a regulation may be issued is to address a market failure. The major types of market failure include externalities, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation; it is not the only reason. Other possible justifications include improving the function of government, correcting distributional unfairness, or securing privacy or personal freedom.

Environmental problems are classic examples of externalities – uncompensated benefits or costs imposed on another party as a result of one's actions. For example, the smoke from a factory may adversely affect the health of local residents and adversely affect the property in nearby neighborhoods. Pollution emitted in one state may be transported across state lines and affect air quality in a neighboring state.

From an economics perspective, achieving emissions reductions (i.e., by establishing the EGU $NO_X$ ozone-season emissions budgets in this rule) through a market-based mechanism is a straightforward and cost-effective remedy to address an externality in which firms emit pollutants, resulting in health and environmental problems without compensation for those incurring the problems. Capping emissions through allowance allocations incentivizes those who emit the pollutants to reduce their emissions, which lessens the impact on those who suffer the health and environmental problems from higher levels of pollution. In addition, emissions rates for non-EGU sources work toward addressing this market failure by requiring affected facilities to reduce NOx emissions.

## 1.2 Overview and Design of the RIA

### *1.2.1 Methodology for Identifying Needed Reductions*

To apply the first and second steps of the CSAPR 4-step Interstate Transport Framework to interstate transport for the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023 and 2026. The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis was then repeated using projected ozone concentrations for 2026. In these analyses, downwind air quality problems are defined by receptors that are projected to be unable to attain (i.e., nonattainment receptor) or maintain (i.e., maintenance receptor) the 2015 ozone NAAQS.[26]

To apply the second step of the Interstate Transport Framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors. Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS. States with contributions that equal or exceed 1 percent of the NAAQS are identified as warranting further analysis for significant contribution to nonattainment or interference with maintenance.[27] States with contributions below 1 percent of the NAAQS are considered to not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

To apply the third step of the Interstate Transport Framework, the EPA applied a multi-factor test to evaluate cost, available emissions reductions, and downwind air quality impacts to determine the appropriate level of NOx control stringency that addresses the impacts of interstate transport on downwind nonattainment or maintenance receptors. The EPA used this multi-factor assessment to gauge the extent to which emissions reductions are needed, and to ensure any required reductions do not result in over-control.

For EGUs, in identifying levels of uniform control stringency the EPA assessed the same $NO_X$ emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available for EGUs: (1) fully operating existing SCR, including both optimizing $NO_X$ removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art $NO_X$ combustion controls; (3) fully operating existing SNCRs, including both optimizing $NO_X$ removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (i.e., emission reductions anticipated to occur from generation shifting from higher to lower emitting units). The selected

[26] *See* Section IV.D of the preamble for a full discussion of the final rule's approach to receptor identification, including the consideration of "violating monitor" maintenance-only receptors.
[27] The EPA assessed the magnitude of the maximum projected design value for 2023 at each receptor in relation to the 2015 ozone NAAQS. Where the value exceeds the NAAQS, the EPA determined that receptor to be a maintenance receptor for purposes of defining interference with maintenance. That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have a maintenance problem in 2023.

levels of uniform control stringency were represented by $1,800 per ton of $NO_X$ (2016$) in 2023 and $11,000 per ton of NOx (2016$) in 2026.[28]

For non-EGUs, the EPA developed an analytical framework to determine which industries and emission unit types to include in a proposed Transport FIP for the 2015 ozone NAAQS transport obligations. A February 28, 2022 memorandum, titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*, documents the analytical framework used to identify industries and emissions unit types included in the proposed FIP.[29] To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP.[30] The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. For a discussion of changes to emissions limits between the proposed FIP and the final rule, see Section V.C of the preamble to the final rule and the Final Non-EGU Sectors TSD.

Below is a summary of the adjustments and additions to the emissions limits for non-EGUs the EPA made between the proposed FIP and this final rule.

- For Pipeline Transportation of Natural Gas, the EPA is finalizing the same emissions limits as proposed; however, the EPA is adjusting the applicability criteria to exclude emergency engines. Further, to allow for the industry to install controls on the engines with the largest potential for emissions reductions at cost-effective thresholds, the final regulations allow for the use of facility-wide emissions averaging for engines in the industry.

[28] EGU $NO_X$ Mitigation Strategies Final Rule TSD, in the docket for this rule (Docket ID No. EPA-HQ-OAR-2021-0688).
[29] The memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.
[30] The TSD is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.

- For Cement and Concrete Product Manufacturing, in the final rule the EPA has removed the daily source cap limit, which could have resulted in an artificially restrictive $NO_X$ emissions limit for affected cement kilns due to lower operating periods resulting from to the COVID-19 pandemic.
- For Iron and Steel and Ferroalloy Manufacturing, the EPA is only finalizing a test-and-set requirement for reheat furnaces premised on the installation of low-$NO_X$ burners. By not finalizing the other proposed emissions limits that were likely to require the installation of SCR, the EPA has addressed the various concerns regarding the feasibility and cost-effectiveness of installation of the other proposed controls at other unit types at these facilities.
- For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions.
- For boilers in Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, the EPA is finalizing a low-use exemption to eliminate the need to install controls on low-use boilers that would have resulted in relatively small reductions.
- For municipal waste combustors in Solid Waste Combustors and Incinerators, the EPA is finalizing emissions limits, summarized in Table ES-1.

For the final rule, to determine $NO_X$ emissions reduction potential for the industries and emissions unit types with the exception of Solid Waste Combustors and Incinerators, we used a 2019 inventory prepared from the emissions inventory system (EIS) to estimate a list of emissions units captured by the applicability criteria for the final rule. For Solid Waste Combustors and Incinerators, the EPA estimated the list for MWCs using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook.[31] Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain control technologies could meet the final emissions limits.[32] Rather than run the Control Strategy Tool to estimate emissions reductions and costs, we programmed the assessment using R to

[31] Available here: https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.
[32] The Technical Support Document (TSD) for the Final Rule, Non-EGU Sectors TSD is available in the docket.

estimate $NO_x$ emission reductions and their costs.[33] Specifically, using the list of emissions units estimated to be captured by the final rule applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB),[34] the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled "*Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs*" available in the docket.

*1.2.2 States Covered by the Rule*

For EGUs, the Transport FIP for the 2015 ozone NAAQS requires EGUs in 22 states to participate in the CSAPR $NO_X$ Ozone Season Group 3 Trading Program created by the Revised CSAPR Update.[35]

- The following twelve states currently participating in the Group 3 Trading Program would remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.
- Affected EGUs in seven states currently covered by the CSAPR $NO_X$ Ozone Season Group 2 Trading Program – Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin – would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period.

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[33] R is a free software environment for statistical computing and graphics. Additional information is available here: https://www.r-project.org/. The R code that processed the data to estimate the emissions reductions and costs is available upon request.
[34] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[35] As explained in Section V.C.1 of the preamble, the EPA finds that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

- Affected EGUs in three states not currently covered by any CSAPR trading program for seasonal $NO_X$ emissions – Minnesota, Nevada, and Utah – would enter the Group 3 trading program in the 2023 control period following the effective date of this final rule.

In addition, the EPA is revising other aspects of the Group 3 trading program to provide improved environmental outcomes and increase compliance, as described in Section VI of the preamble. Revisions include dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank. The final rule does not revise the budget stringency and geography of the existing CSAPR NOx Ozone Season Group 1 trading program.

Aside from the seven states moving from the Group 2 trading program to the Group 3 trading program under the rule, this action otherwise leaves unchanged the budget stringency of the existing CSAPR $NO_X$ Ozone Season Group 2 trading program.

For non-EGUs, the rule includes $NO_X$ emissions limitations with an initial compliance date of May 1, 2026, applicable to certain non-EGU stationary sources in 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

*1.2.3 Regulated Entities*

The rule affects EGUs in 22 states that have a nameplate capacity of greater than 25 megawatts (MWe), which generally fall in 22 states within the utility sector (electric, natural gas, other systems) classified as code 221112 by the North American Industry Classification System (NAICS). In addition, the rule affects certain non-EGUs in 20 states in the following industries, as defined by 4- or 6-digit NAICS: Pipeline Transportation of Natural Gas, 4862; Cement and Concrete Product Manufacturing, 3273; Iron and Steel Mills and Ferroalloy Manufacturing, 3311; Glass and Glass Product Manufacturing, 3272; Metal Ore Mining, 2122; Basic Chemical Manufacturing, 3251; Petroleum and Coal Products Manufacturing, 3241; Pulp, Paper, and Paperboard Mills, 3221; Solid Waste Combustors and Incinerators, 562213. For additional discussion of the non-EGUs affected, see Section V.C. of the preamble.

*1.2.4 Baseline and Analysis Years*

As described in the preamble, the EPA aligns implementation of this rule with relevant attainment dates for the 2015 ozone NAAQS. The rule requires emissions reductions to be achieved as expeditiously as practicable and, to the extent possible, by the next applicable nonattainment dates for downwind areas for the 2015 ozone NAAQS. Thus, initial emissions reductions from EGUs will be required beginning in the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS. The remaining emissions reduction obligations will be phased in as soon as possible thereafter. Substantial additional reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs will phase in beginning in the 2026 ozone season, associated with the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. The final rule will allow individual facilities limited additional time to fully implement the required emissions reductions. For EGUs, the emissions trading program budget stringency associated with retrofit of post-combustion controls will be phased in over two ozone seasons (2026-2027). For industrial sources, the final rule provides a process for individual facilities to seek a one-year extension, with the possibility of up to two additional years, based on a specific showing of necessity. More information regarding the timing elements of the rule can be found in Section VI.A of the preamble.

To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis years of 2023 and 2026, taking into account currently on-the-books Federal regulations, enforcement actions, state regulations, population, and where possible, economic growth.[36] Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by the rule. Federal rules included in the baseline are: the Revised Cross-State Air Pollution Rule (CSAPR) Update, the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources, Reciprocating Internal Combustion Engine (RICE) New Source Performance Standards (NSPS),

[36] The technical support document (TSD) for the 2016v2 emissions modeling platform titled *Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform* is included in the docket for this rule. The TSD includes additional discussion on mobile source rules included in the baseline.

Natural gas turbines NSPS, Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles – Phase 2, and 2017 and Later Model Year Light-Duty Vehicle GHG Emissions and Corporate Average Fuel Economy Standards.

The analysis in this RIA focuses on benefits, costs and certain impacts from 2023 through 2042. We focus on 2023 because it is by the 2023 ozone season, corresponding with the 2024 attainment date for areas classified as Moderate nonattainment, that significant contribution from upwind states' must be eliminated to the extent possible. In addition, impacts for 2026 are important because this ozone season corresponds with the 2027 Serious area attainment date and it is by this ozone season that additional requirements for NOx emissions reductions for EGUs and non-EGUs begin to apply for states whose upwind linkage to downwind receptors persists. The EPA's analysis for the third step of the Interstate Transport Framework reflects emissions reductions for 2023 from EGUs based on a control stringency at a representative cost threshold of $1,800 per ton. Those reductions are commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls. For 2026, the selected control stringency (at a representative cost per ton threshold for EGUs of $11,000 and an overall estimated average cost per ton for non-EGUs of $5,339/ton (2106$), with average cost by industry ranging from $939/ton to $14,595/ton) includes additional EGU controls and estimated non-EGU emissions reductions. See Section V.D of the preamble for additional discussion. Additional benefits and costs are expected to occur after 2026 as EGUs subject to this rule continue to comply with the tighter allowance budget, which is below their baseline emissions, and non-EGUs remain subject to ozone season emissions limits.

The Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA) includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the US generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity.

In addition, we include an appendix to Chapter 4 to describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline to account for the potential effects of the IRA of 2022 on the power sector costs, emission reductions, and other impacts from this final rule. This supplementary analysis quantifies the incremental impacts of the Transport FIP for the 2015 ozone NAAQS under this alternative baseline characterization and compares impacts to the main analyses in Chapter 4. As described in Chapter 4, the power sector analyses that inform air quality modeling in subsequent chapters in this RIA do not include the IRA due to time limitations. However, in the interests of completeness the appendix seeks to quantify the impacts of the IRA on the analyses of power sector impacts of the final rule.

### *1.2.5 Emissions Controls, Emissions, and Cost Analysis Approach*

The EPA estimated the effects of the EGU control strategies in the final rule, including their projected compliance costs, using the Integrated Planning Model (IPM), as well as certain costs that are estimated outside the model but use IPM inputs for their estimation. These cost estimates reflect costs incurred by the power sector and include (but are not limited to) the costs of purchasing, installing, and operating $NO_X$ control technology, changes in fuel costs, and changes in the generation mix. A description of the methodologies used to estimate the costs and economic impacts to the power sector is contained in Chapter 4 of this RIA. This analysis also provides estimates of $NO_X$ emissions changes during the May through September ozone season and year-round, as well as annual emissions changes in $PM_{2.5}$, $SO_2$, and carbon dioxide ($CO_2$) due to changes in power sector operation.

As described in Section 1.2.1 for non-EGUs, to determine $NO_X$ emissions reduction potential for the industries and emissions unit types, except for Solid Waste Combustors and Incinerators, we used a 2019 inventory prepared from the emissions inventory system (EIS) to estimate a list of emissions units captured by the applicability criteria for the final rule and programmed the assessment's estimated emission reductions and costs using R.[37] For Solid Waste Combustors and Incinerators, the EPA estimated the list for MWCs using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook. The EPA did not run the Control Strategy Tool (CoST) to estimate emissions reductions.

[37] R is a free software environment for statistical computing and graphics. Additional information is available here: https://www.r-project.org/.The R code that processed the data to estimate the emissions reductions and costs is available upon request.

Using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB)[38,39], the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of $SO_2$, $PM_{2.5}$, $CO_2$ and other pollutants that may be associated with controls on non-EGU emissions units. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs* available in the docket.

### *1.2.6 Benefits Analysis Approach*

Implementing the Transport FIP for the 2015 ozone NAAQS is expected to reduce emissions of $PM_{2.5}$, $NO_X$ and $SO_2$ throughout the year. Because $NO_X$ and $SO_2$ are also precursors to formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects. In addition, we estimate the climate benefits of $CO_2$ emissions reductions expected from this final rule using the SC-$CO_2$ estimates.

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

[39] The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may be different than those estimated in this assessment; the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

## 1.3 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining chapters:

- *Chapter 2: Industry Sector Profiles.* This chapter describes the electric power sector in detail, as well as provides an overview of the other non-EGU industries.
- *Chapter 3*: *Air Quality Impacts*. The data, tools, and methodology used for the air quality modeling are described in this chapter, as well as the post-processing techniques used to produce air quality metric values for input into the analysis of benefits and costs.
- *Chapter 4: Cost, Emissions, and Energy Impacts.* The chapter summarizes the data sources and methodology used to estimate the costs and other impacts incurred by the power sector. The chapter summarizes the non-EGU assessment used to estimate emissions reductions and costs for the non-EGU industries.
- *Chapter 5: Benefits*. The chapter presents the health-related benefits of the ozone and PM related air quality improvements and the climate benefits of $CO_2$ emissions reductions.
- *Chapter 6: Economic Impacts*. The chapter includes a discussion of small entity, economic, and labor impacts.
- *Chapter 7: Environmental Justice Impacts.* This chapter includes an assessment of downwind ozone impacts across communities with potential environmental justice concerns.
- *Chapter 8: Comparison of Benefits and Costs*. The chapter compares estimates of the total benefits with total costs and summarizes the net benefits of the three regulatory control alternatives analyzed.

# CHAPTER 2: INDUSTRY SECTOR PROFILES

## Overview

This chapter discusses important aspects of the regulated industries that relate to the final rule with respect to the interstate transport of emissions of nitrogen oxides ($NO_X$) that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in downwind states. This chapter describes types of existing power-sector sources affected by the regulation and provides background on the power sector and electricity generating units (EGUs). In addition, this chapter also briefly describes the relevant non-EGU industries included in the regulation.

## 2.1 Background

In the past decade there have been significant structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, specifically the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more natural gas being used as base load energy in addition to supplying electricity during peak load. Additionally rapid growth in the penetration of renewables has led to their now constituting a significant share of generation. This chapter presents data on the evolution of the power sector from 2014 through 2021. Projections of future power sector behavior and the impact of this proposed rule are discussed in more detail in Chapter 4 of this RIA.

## 2.2 Power Sector Overview

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

*2.2.1 Generation*

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation: capacity and net generation. *Generating Capacity* refers to the maximum amount of production an EGU is capable of producing in a typical hour, typically measured in megawatts (MW) for individual units, or gigawatts (1 GW = 1,000 MW) for multiple EGUs. *Electricity Generation* refers to the amount of electricity actually produced by an EGU over some period of time, measured in kilowatt-hours (kWh) or gigawatt-hours (1 GWh = 1 million kWh). Net Generation is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). Electricity generation is most often reported as the total annual generation (or some other period, such as seasonal). In addition to producing electricity for sale to the grid, EGUs perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Furthermore, EGUs relying on renewable resources such as wind, sunlight and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight, or water at different times of the day and season. Units are also unavailable during routine and unanticipated outages for maintenance. These factors result in the mix of generating capacity types available (e.g., the share of capacity of each type of EGU) being substantially different than the mix of the share of total electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity over 2015-2021.

In 2021 the power sector comprised a total capacity[40] of 1,179 GW, an increase of 105 GW (or 10 percent) from the capacity in 2015 (1,074 GW). The largest change over this period was the decline of 70 GW of coal capacity, reflecting the retirement/rerating of over a third of the coal fleet. This reduction in coal capacity was offset by an increase in natural gas capacity of 52 GW, and an increase in solar (48 GW) and wind (60 GW) capacity over the same period. Additionally, significant amounts of distributed solar (23 GW) were also added.

**Table 2-1. Total Net Summer Electricity Generating Capacity by Energy Source, 2014 and 2021**

| | 2015 | | 2021 | | Change Between '15 and '21 | |
|---|---|---|---|---|---|---|
| **Energy Source** | **Net Summer Capacity (GW)** | **% Total Capacity** | **Net Summer Capacity (GW)** | **% Total Capacity** | **% Increase** | **Capacity Change (GW)** |
| Coal | 280 | 26% | 210 | 18% | -25% | -70 |
| Natural Gas | 439 | 41% | 492 | 42% | 12% | 52 |
| Nuclear | 99 | 9% | 96 | 8% | -3% | -3 |
| Hydro | 102 | 10% | 103 | 9% | 1% | 1 |
| Petroleum | 37 | 3% | 28 | 2% | -23% | -9 |
| Wind | 73 | 7% | 133 | 11% | 83% | 60 |
| Solar | 14 | 1% | 62 | 5% | 350% | 48 |
| Distributed Solar | 10 | 1% | 33 | 3% | 238% | 23 |
| Other Renewable | 17 | 2% | 15 | 1% | -10% | -2 |
| Misc | 4 | 0% | 8 | 1% | 91% | 4 |
| Total | 1,074 | 100% | 1,179 | 100% | 10% | 105 |

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.
Source: EIA. Electric Power Annual 2022, Tables 4.2

[40] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power facilities classified as Independent Power Producers (IPP) and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine, Gas Turbine, steam, and miscellaneous (< 1 percent).

The information in Table 2-1 presents information about the generating capacity in the entire U.S. The Federal Implementation Plan (FIP) Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS), however, directly affects EGUs in 22 eastern states. The share of generating capacity from each major type of generation differs between the FIP for the 2015 NAAQS Ozone Region and the rest of the U.S. (non-region). Figure 2-1 shows the mix of generating capacity for each region. In 2021, the overall capacity in the Transport FIP for the 2015 Ozone NAAQS Region is 56 percent of the national total, reflecting the larger total population in the region. The mix of capacity is noticeably different in the two regions. In the Transport FIP for the 2015 Ozone NAAQS Region in 2020, coal makes up a significantly larger share of total capacity (23 percent) than it does in the rest of the country (16 percent). The share of natural gas in the Transport FIP for the 2015 Ozone NAAQS Region is 50 percent as compared to 41 percent in the rest of the country. The difference in the share of coal's capacity is primarily balanced by relatively more hydro, wind, and solar capacity in the rest of country compared to the Transport FIP for the 2015 Ozone NAAQS Region.

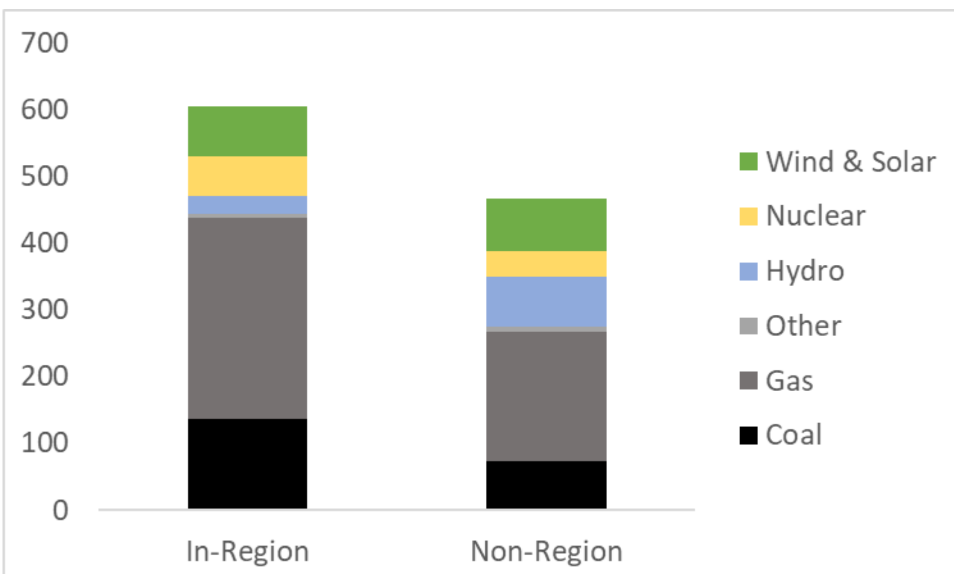


**Figure 2-1. Regional Differences in Generating Capacity (GW), 2021**
Source: NEEDSv6.21

In 2021, electric generating sources produced a net 4,157 TWh to meet national electricity demand, which was around 2% higher than 2015. As presented in Table 2-2, 59 percent of electricity in 2021 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. The total generation share from fossil fuels in 2021 (60%) was 11% less than the share in 2010 (69%). Moreover, the share of fossil generation supplied by coal fell from 65% in 2010 to 36% by 2021, while the share of fossil generation supplied by natural gas rose from 35% to 64% over the same period. In absolute terms, coal generation declined by 51 percent, while natural gas generation increased by 60 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. The combination of wind and solar generation also grew from 2 percent of the mix in 2010 to 13 percent in 2021.

**Table 2-2. Net Generation in 2015 and 2021 (Trillion kWh = TWh)**

| | 2015 | | 2021 | | Change Between '15 and '21 | |
|---|---|---|---|---|---|---|
| **Energy Source** | **Net Generation (TWh)** | **Fuel Source Share** | **Net Generation (TWh)** | **Fuel Source Share** | **% Increase** | **Generation Change (TWh)** |
| Coal | 1,352 | 33% | 898 | 22% | -34% | -455 |
| Natural Gas | 1,333 | 33% | 1,579 | 38% | 18% | 246 |
| Nuclear | 797 | 19% | 778 | 19% | -2% | -19 |
| Hydro | 244 | 6% | 246 | 6% | 1% | 2 |
| Petroleum | 28 | 1% | 19 | 0% | -32% | -9 |
| Wind | 191 | 5% | 378 | 9% | 98% | 187 |
| Solar | 25 | 1% | 115 | 3% | 363% | 90 |
| Distributed Solar | 14 | 0% | 49 | 1% | 248% | 35 |
| Other Renewable | 80 | 2% | 70 | 2% | -12% | -9 |
| Misc | 27 | 1% | 24 | 1% | -13% | -4 |
| Total | 4,092 | 100% | 4,157 | 100% | 2% | 66 |

Source: EIA. Electric Power Annual 2022, Tables 3.2

The average age of coal-fired power plants that have retired between 2015 and 2021 is over 50 years. Older power plants tend to become uneconomic over time as they become more costly to maintain and operate, and as newer and more efficient alternative generating technologies are built. As a result, coal's share of total U.S. electricity generation has been declining for over a decade, while generation from natural gas and renewables has increased significantly.[41] As shown in Figure 2-2 below, 65% of the coal fleet in 2021 had an average age of over 40 years.

[41] EIA, Today in Energy (April 17, 2017) *available at* https://www.eia.gov/todayinenergy/detail.php?id=30812

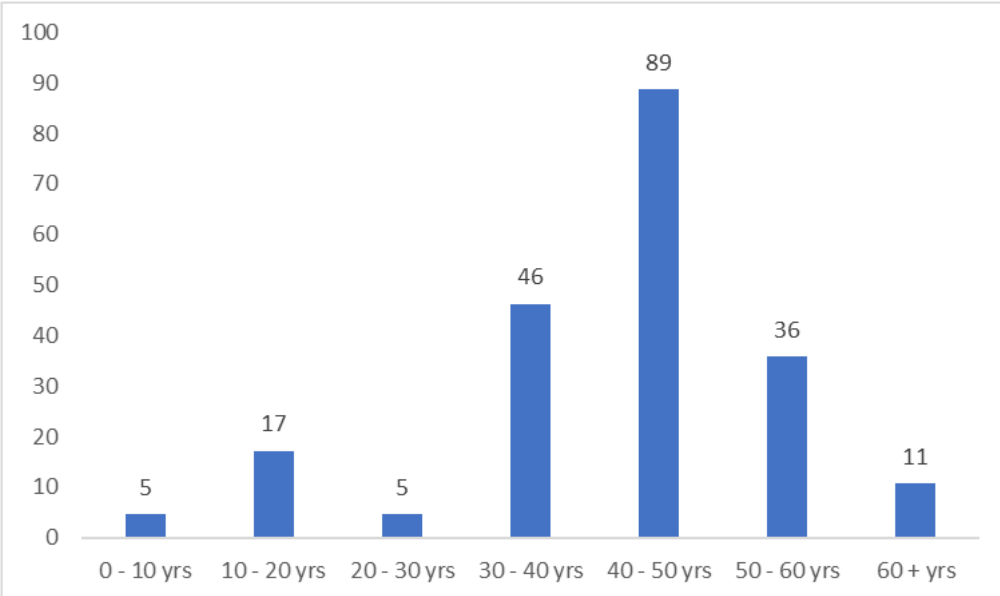


**Figure 2-2. National Coal-fired Capacity (GW) by Age of EGU, 2021**
Source: NEEDS v6

Coal-fired and nuclear generating units have historically supplied "base load" electricity, the portion of electricity loads that are continually present and typically operate throughout all hours of the year. Although much of the coal fleet has historically operated as base load, there can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied "peak" and "intermediate" power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced. Moreover, as shown in Figure 2-3, average annual coal capacity factors have declined from 67% to 49% over the 2010-2021 period, indicating that a larger share of units are operating in non-baseload fashion. Over the same period, natural gas capacity factors have risen from an annual average of 28% to 37%.

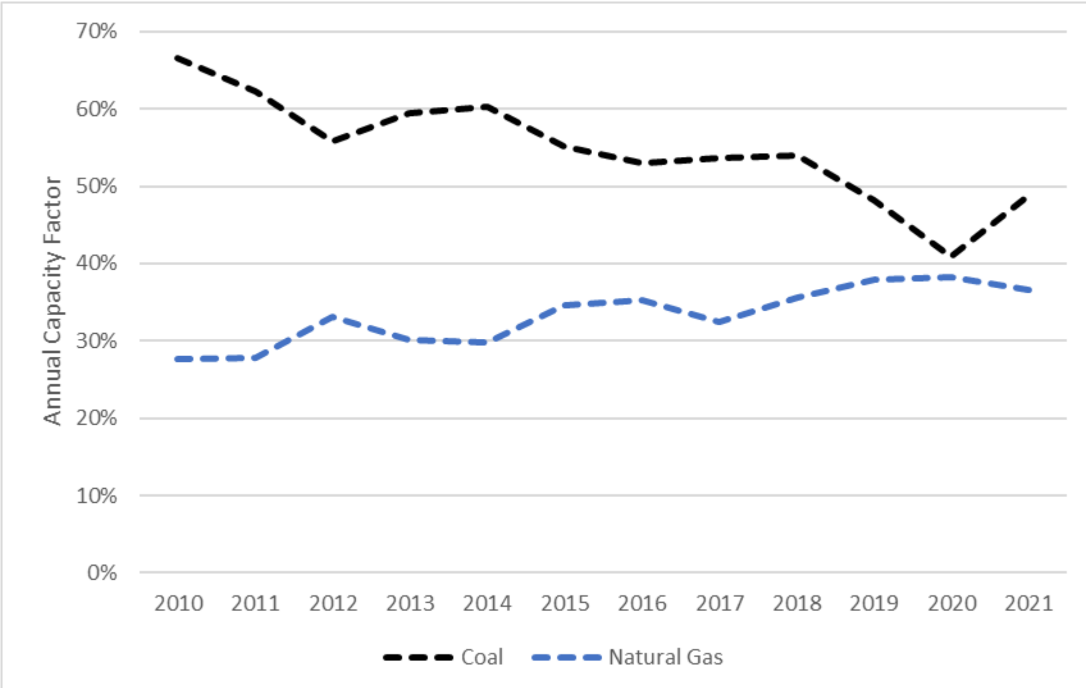


**Figure 2-3. Average Annual Capacity Factor by Energy Source**
Source: EIA. Electric Power Annual 2022, Tables 3.2 and 4.2

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. While 67 percent of the coal EGU fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit.

**Table 2-3. Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2020**

| Unit Size Grouping (MW) | No. Units | % of All Units | Avg. Age | Avg. Net Summer Capacity (MW) | Total Net Summer Capacity (MW) | % Total Capacity | Avg. Heat Rate (Btu/kWh) |
|---|---|---|---|---|---|---|---|
| COAL | | | | | | | |
| 0 – 24 | 31 | 6% | 49 | 11 | 351 | 0% | 11,379 |
| 25 – 49 | 32 | 6% | 35 | 36 | 1,150 | 1% | 11,541 |
| 50 – 99 | 24 | 5% | 39 | 76 | 1,823 | 1% | 11,649 |
| 100 – 149 | 36 | 7% | 50 | 122 | 4,388 | 2% | 11,167 |
| 150 – 249 | 61 | 12% | 52 | 197 | 12,027 | 6% | 10,910 |
| 250 – 499 | 132 | 26% | 42 | 372 | 49,090 | 24% | 10,700 |
| 500 – 749 | 138 | 27% | 41 | 609 | 83,978 | 40% | 10,315 |
| 750 – 999 | 50 | 10% | 38 | 827 | 41,345 | 20% | 10,135 |
| 1000 – 1500 | 11 | 2% | 43 | 1,264 | 13,903 | 7% | 9,834 |
| Total Coal | 515 | 100% | 43 | 404 | 208,056 | 100% | 10,718 |
| NATURAL GAS | | | | | | | |
| 0 – 24 | 4,329 | 54% | 31 | 5 | 21,626 | 4% | 13,244 |
| 25 – 49 | 932 | 12% | 26 | 41 | 38,089 | 8% | 11,759 |
| 50 – 99 | 1,018 | 13% | 27 | 71 | 72,744 | 15% | 12,163 |
| 100 – 149 | 410 | 5% | 23 | 126 | 51,567 | 10% | 9,447 |
| 150 – 249 | 1,041 | 13% | 18 | 179 | 186,494 | 37% | 8,226 |
| 250 – 499 | 293 | 4% | 21 | 332 | 97,244 | 19% | 8,293 |
| 500 – 749 | 37 | 0% | 38 | 592 | 21,910 | 4% | 10,384 |
| 750 – 999 | 10 | 0% | 46 | 828 | 8,278 | 2% | 11,294 |
| 1000 – 1500 | 1 | 0% | 0 | 1,060 | 1,060 | 0% | 7,050 |
| Total Gas | 8,060 | 100% | 28 | 62 | 499,012 | 100% | 11,900 |

Source: National Electric Energy Data System (NEEDS) v.6
Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency.

In terms of the age of the generating units, almost 50 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-4 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-4 also includes the distribution of generation, which is similar to the distribution of capacity.

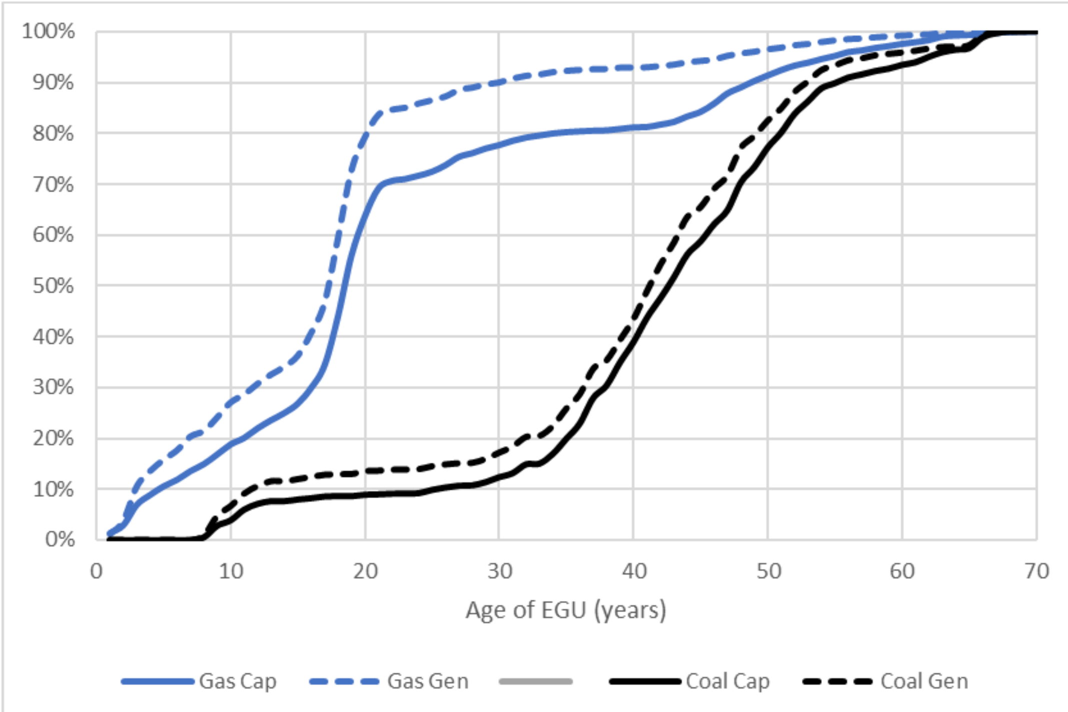


**Figure 2-4. Cumulative Distribution in 2019 of Coal and Natural Gas Electricity Capacity and Generation, by Age**

Source: eGRID 2020 (January 2022 release from EPA eGRID website). Figure presents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGrid data includes generators that came online as far back as 1915. Full data from 1915 onward is used in calculating cumulative distributions; figure truncation at 70 years is merely to improve visibility of diagram.

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-5.

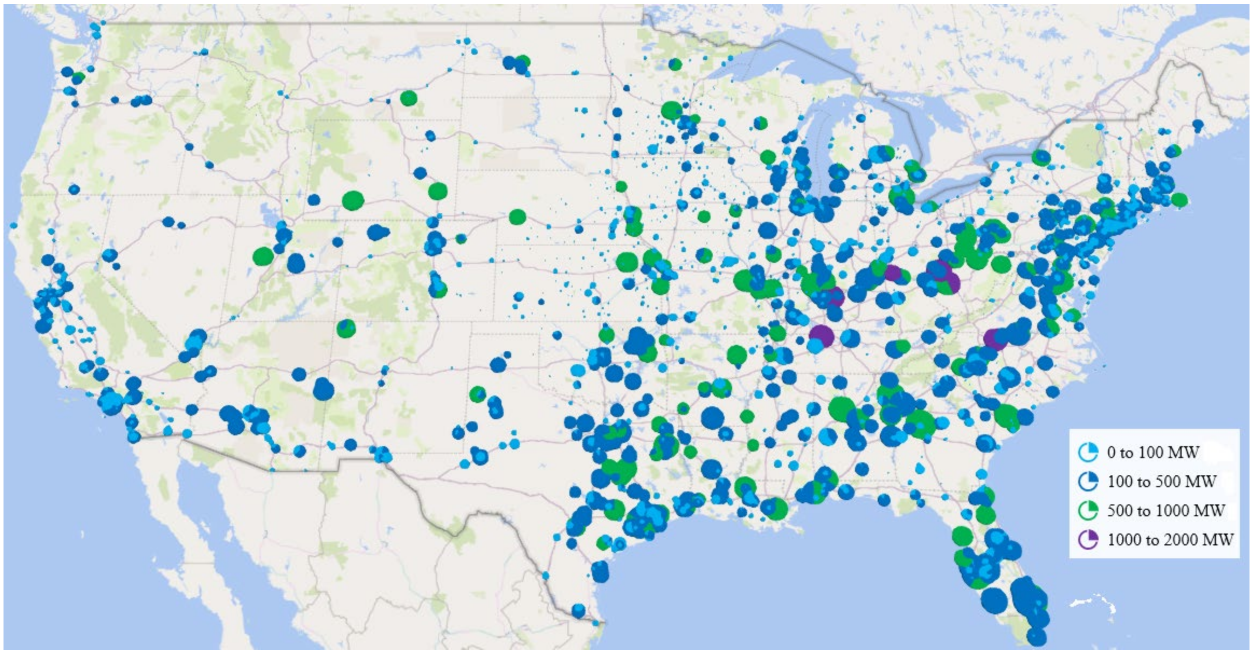


**Figure 2-5. Fossil Fuel-Fired Electricity Generating Facilities, by Size**
Source: National Electric Energy Data System (NEEDS) v.6
Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2023. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

*2.2.2 Transmission*

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[42] each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator;[43] in others, individual utilities[44] coordinate the operations of their generation,

[42] These three network interconnections are the Western Interconnection, comprising the western parts of both the US and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the US and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.
[43] For example, PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).
[44] For example, Los Angeles Department of Power and Water, Florida Power and Light.

transmission, and distribution systems to balance the system across their respective service territories.

### *2.2.3 Distribution*

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last few decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

## 2.3 Sales, Expenses, and Prices

These electric generating sources provide electricity for ultimate commercial, industrial and residential customers. Each of the three major ultimate categories consume roughly a quarter to a third of the total electricity produced[45] (see Table 2-4). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while

[45] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2015 and 2021.

**Table 2-4. Total U.S. Electric Power Industry Retail Sales, 2015 and 2021 (billion kWh)**

| | | 2015 | | 2021 | |
|---|---|---|---|---|---|
| | | **Sales/Direct Use (Billion kWh)** | **Share of Total End Use** | **Sales/Direct Use (Billion kWh)** | **Share of Total End Use** |
| **Sales** | Residential | 1,404 | 36% | 1,470 | 37% |
| | Commercial | 1,361 | 35% | 1,328 | 34% |
| | Industrial | 987 | 25% | 1,001 | 25% |
| | Transportation | 8 | 0% | 6 | 0% |
| **Total** | | 3,759 | 96% | 3,806 | 96% |
| **Direct Use** | | | 141 | 4% | 139 |
| **Total End Use** | | | **3,900** | **100%** | **3,945** |

Source: Table 2.2, EIA Electric Power Annual, 2021
Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net imported electricity and loss of electricity that occurs through transmission and distribution, along with data collection frame differences and non-sampling error. Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions.

### *2.3.1 Electricity Prices*

Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of distributing electricity to individual homes and commercial establishments. The higher prices for residential and commercial customers are the result both of the necessary extensive distribution network reaching to virtually every part of the country and every building, and also the fact that generating stations are increasingly located relatively far from population centers (which increases transmission costs). Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers receive electricity at higher voltages (which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity, varying by the season and time of day, while residential and commercial prices historically have been less variable. Overall industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2021, the national average retail electricity price (all sectors) was 11.18 cents/KWh, with a range from 7.5 cents (Louisiana) to 27 cents (Hawaii).[46]

Average national retail electricity prices decreased between 2010 and 2021 by 8 percent in real terms (2019$), and 5% between 2015-21.[47] The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average industrial prices decreased the most (7 percent), and residential prices decreased the least (4 percent) between 2015-21. The real year prices for 2010 through 2021 are shown in Figure 2-6.

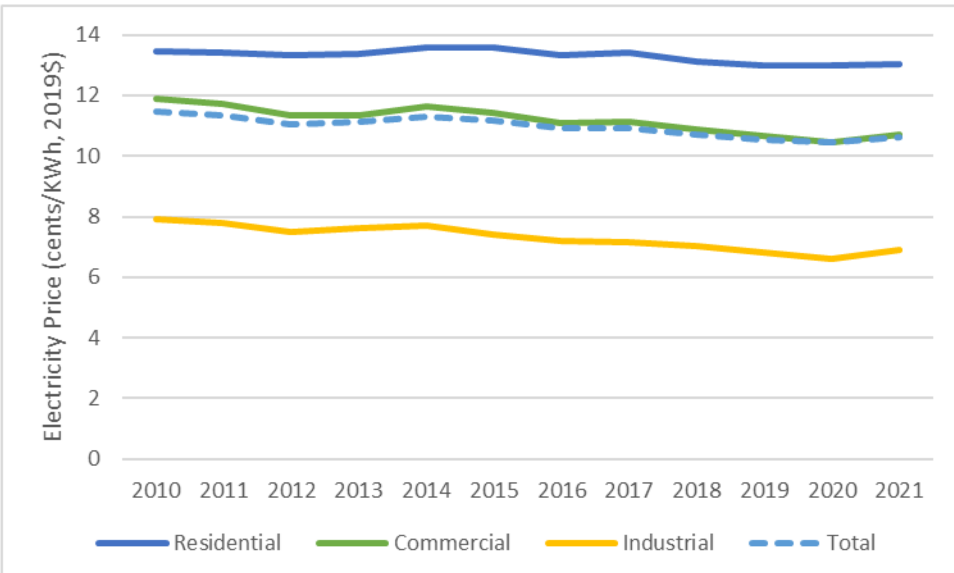


**Figure 2-6. Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories**

Source: EIA. Electric Power Annual 2021, Table 2.4.

Most of these electricity price decreases occurred between 2014 and 2015, when nominal residential electricity prices followed inflation trends, while nominal commercial and industrial electricity prices declined. The years 2016 and 2017 saw an increase in nominal commercial and industrial electricity prices, while 2018 and 2019 saw flattening of this growth. Industrial electricity prices declined in 2019 and 2020 due to the effects of the pandemic. Prices rose in 2021 as a result of higher input fuel prices and increasing demand. The increase in nominal

[46] EIA State Electricity Profiles with Data for 2021 (http://www.eia.gov/electricity/state/)
[47] All prices in this section are estimated as real 2019 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

electricity prices for the major end use categories, as well as increases in the GDP price index for comparison, are shown in Figure 2-7.

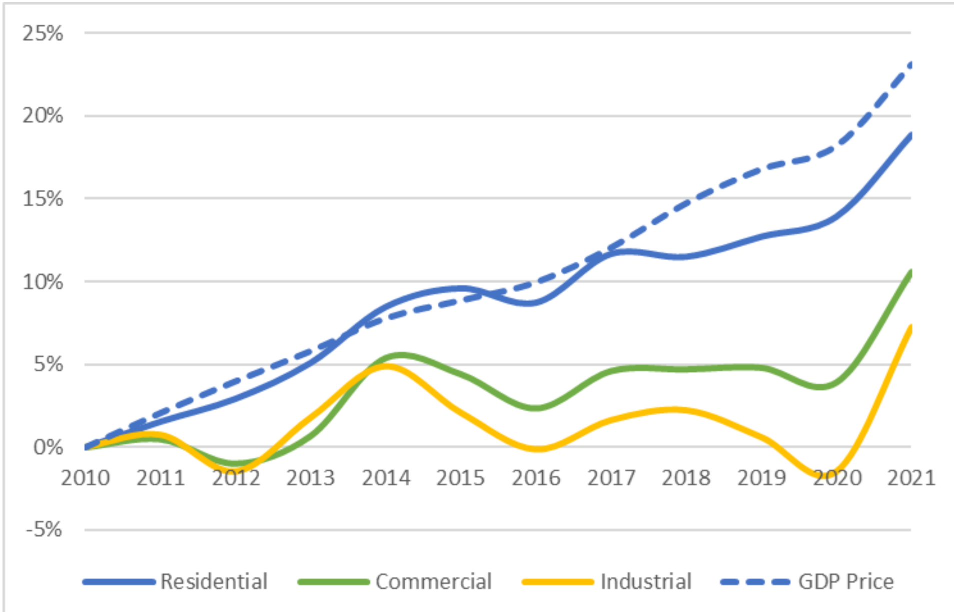


**Figure 2-7. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories (including taxes), With Inflation Indices**
Source: EIA. Electric Power Annual 2021, Table 2.4.

*2.3.2 Prices of Fossil Fuels Used for Generating Electricity*

Another important factor in the changes in electricity prices are the changes in delivered fuel prices[48] for the three major fossil fuels used in electricity generation: coal, natural gas and petroleum products. Relative to real prices in 2014, the national average real price (in 2019$) of coal delivered to EGUs in 2020 had decreased by 26 percent, while the real price of natural gas decreased by 56 percent. The real price of delivered petroleum products also decreased by 55 percent, and petroleum products declined as an EGU fuel (in 2020 petroleum products generated 1 percent of electricity). The combined real delivered price of all fossil fuels (weighted by heat input) in 2020 decreased by 39 percent over 2014 prices. Figure 2-8 shows the relative changes in real price of all 3 fossil fuels between 2010 and 2021.

[48] Fuel prices in this section are all presented in terms of price per MMBtu to make the prices comparable.

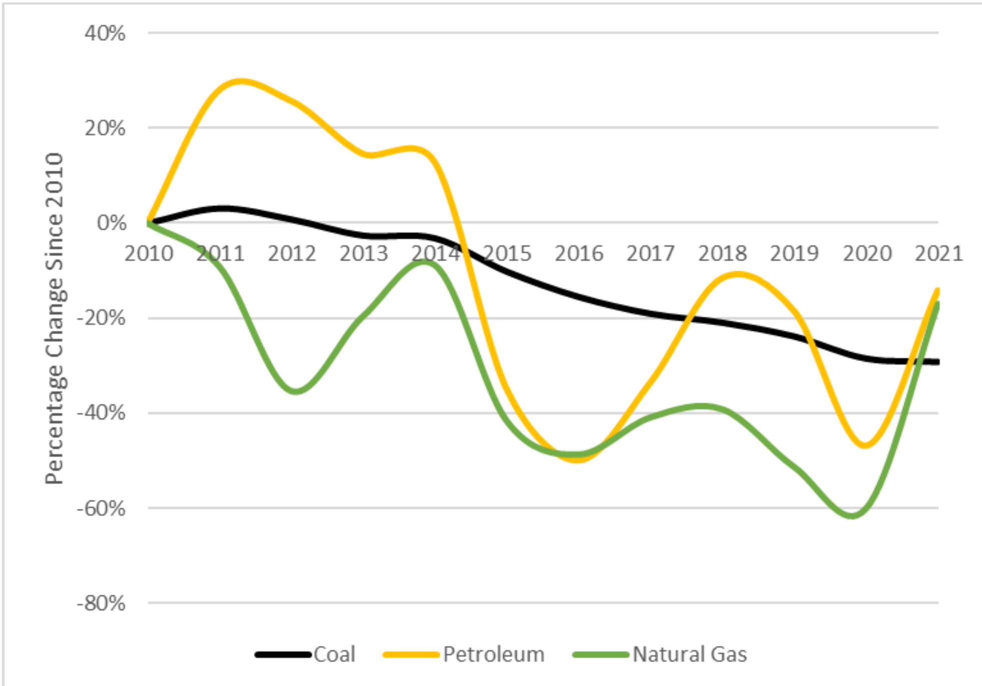


**Figure 2-8. Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU**
Source: EIA. Electric Power Annual 2020 and 2021, Table 7.1.

*2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2015 to 2021*

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2010 and 2021 is that while total net generation increased by 1 percent over that period, the demand growth for generation was lower than both the population growth (7 percent) and real GDP growth (24 percent). Figure 2-9 shows the growth of electricity generation, population and real GDP during this period.

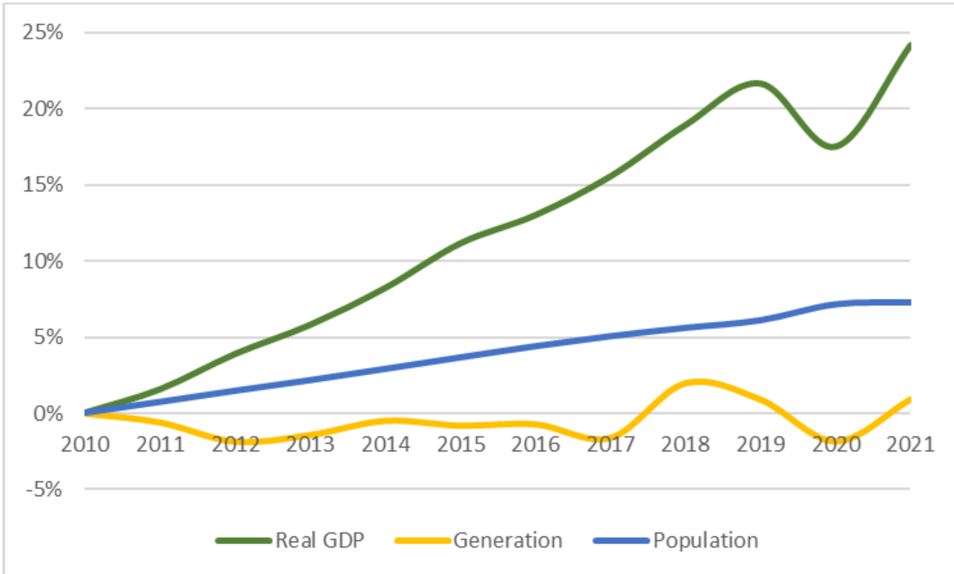


**Figure 2-9. Relative Growth of Electricity Generation, Population and Real GDP Since 2014**

Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2020. Population: U.S. Census. Real GDP: 2022 Economic Report of the President, Table B-3.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2010 to 2021. On a per capita basis, real GDP per capita grew by 16 percent between 2010 and 2021. At the same time electricity generation per capita decreased by 6 percent. The combined effect of these two changes improved the overall electricity generation efficiency in the U.S. market economy. Electricity generation per dollar of real GDP decreased 19 percent. These relative changes are shown in Figure 2-10.

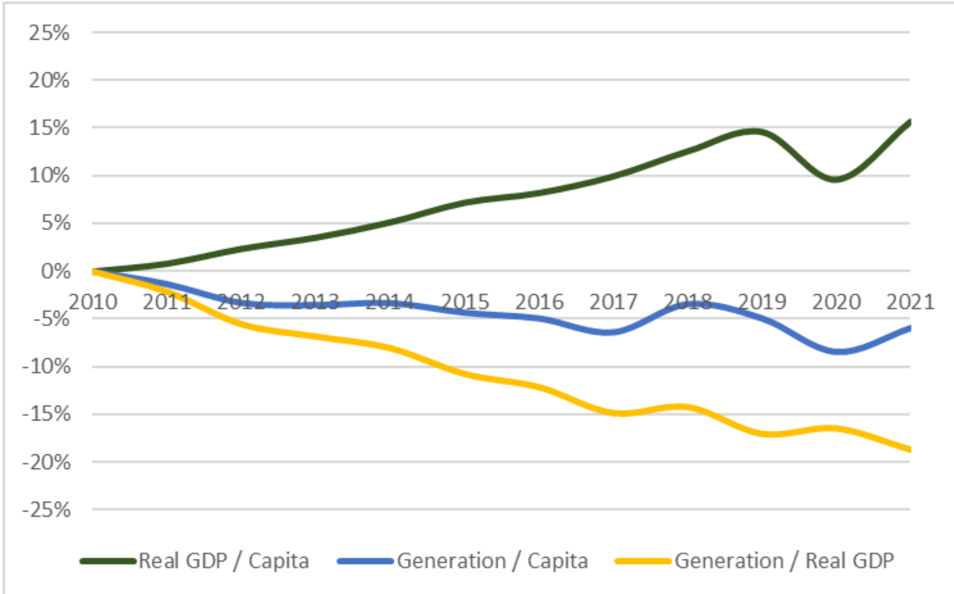


**Figure 2-10. Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2014**
Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2020. Population: U.S. Census. Real GDP: 2022 Economic Report of the President, Table B-3.

### 2.4 Industrial Sectors Overview

The final rule establishes various ozone season $NO_x$ emission limits beginning in 2026, including emissions limits for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; for kilns in Cement and Cement Product Manufacturing; for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; for furnaces in Glass and Glass Product Manufacturing; for boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors or incinerators in Solid Waste Combustors and Incinerators.[49] Figure 2-11 shows the locations[50] of the estimated non-EGU emissions reductions by industry. For additional discussion of the emissions limits, see Section I.B. of the preamble. The following sections provide overviews of these industries. For additional information on these non-EGU industries please see the Final Non-EGU Sectors TSD in the docket.

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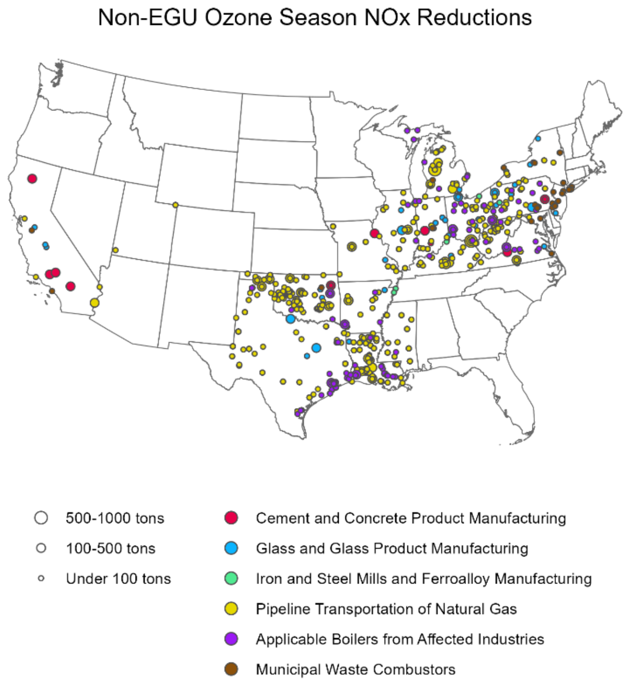
[49] Boilers with design capacity of 100 mmBtu/hr or greater.
[50] Facility location information is based on the 2019 inventory, which is discussed in Chapter 4, Section 4.5.4.




| State | Cement and Concrete Product Manufacturing | Glass and Glass Product Manufacturing | Iron and Steel Mills and Ferroalloy Manufacturing | Pipeline Transportation of Natural Gas | Applicable Boilers from Affected Industries | Municipal Waste Combustors | Total |
|---|---|---|---|---|---|---|---|
| LA | 0 | 115 | 0 | 6,200 | 827 | 0 | 7,142 |
| TX | 0 | 818 | 0 | 3,171 | 702 | 0 | 4,691 |
| OK | 276 | 101 | 0 | 3,596 | 314 | 100 | 4,388 |
| OH | 0 | 275 | 114 | 2,244 | 472 | 0 | 3,105 |
| MI | 0 | 27 | 0 | 2,637 | 262 | 59 | 2,985 |
| KY | 0 | 22 | 13 | 2,624 | 7 | 0 | 2,665 |
| MS | 0 | 0 | 0 | 2,428 | 71 | 0 | 2,499 |
| IL | 0 | 297 | 0 | 1,943 | 71 | 0 | 2,311 |
| VA | 398 | 93 | 0 | 969 | 495 | 246 | 2,200 |
| PA | 171 | 791 | 9 | 574 | 173 | 466 | 2,184 |
| MO | 114 | 76 | 0 | 1,875 | 0 | 0 | 2,065 |
| IN | 478 | 220 | 228 | 737 | 96 | 217 | 1,976 |
| WV | 0 | 0 | 0 | 1,475 | 174 | 0 | 1,649 |
| CA | 1,135 | 160 | 0 | 213 | 0 | 92 | 1,600 |
| AR | 0 | 37 | 35 | 1,065 | 409 | 0 | 1,546 |
| NY | 0 | 80 | 9 | 230 | 116 | 523 | 958 |
| UT | 0 | 0 | 0 | 252 | 0 | 0 | 252 |
| NJ | 0 | 18 | 0 | 0 | 0 | 224 | 242 |
| MD | 0 | 0 | 0 | 13 | 0 | 145 | 157 |

**Figure 2-11. Geographical Distribution of Non-EGU Ozone Season NOx Reductions and Summary of Reductions by Industry and by State**

### *2.4.1 Cement and Cement Product Manufacturing*

Hydraulic cement (primarily portland cement) is a key component of an important construction material: concrete. Concrete is used in a wide variety of applications (e.g., residential and commercial buildings, public works projects), and cement demand is influenced by national and regional trends in these sectors.

Portland cement is a fine powder, gray or white in color, that consists of a mixture of hydraulic cement materials comprising primarily calcium silicates, aluminates and alumino-ferrites. More than 30 raw materials are known to be used in the manufacture of portland cement, and these materials can be divided into four distinct categories: calcareous, siliceous, argillaceous, and ferriferous (containing iron). These materials are chemically combined through pyroprocessing (heat) and subjected to subsequent mechanical processing operations to form gray and white portland cement. Gray portland cement is used for structural applications and is the more common type of cement produced. White portland cement has lower iron and manganese contents than gray portland cement and is used primarily for decorative purposes.

There are two processes for manufacturing cement: the wet process and the dry process. In the wet process, water is added to the raw materials during the blending process and before feeding the mixture into the rotary kiln. In contrast, the dry process feeds the blended material directly into the rotary kiln in a dry state. Newer dry process plants also use preheater and precalciner technologies that partially heat and calcine the blended raw materials before they enter the rotary kiln. These technologies can increase the overall energy efficiency of the cement plant and reduce production costs. The fuel efficiency differences between the wet and dry processes have led to a substantial decline in clinker capacity provided by the wet process over the last 3 decades. (Van Oss and Padovani, 2002). The number of wet process plants fell from 32 in 2000 to 7 in 2017 (DOI, USGS, 2020).

Cement kilns are used by the cement industry in the production of cement. Portland cement, used in almost all construction applications, is the industry's primary product. Essentially all of the NOx emissions associated with cement manufacturing are generated in the kilns because of high process temperatures. To manufacture cement, raw materials such as limestone, cement rock, sand, iron ore, clay and shale are crushed, blended, and fed into a kiln. These materials are then heated in the kiln to temperatures above 2900°F to induce a chemical reaction (called "fusion") that produces cement "clinker," a round, marble-sized, glass-hard material. The clinker is then cooled, mixed with gypsum and ground to produce cement. Clinker is also defined as the product of a portland cement kiln from which finished cement is manufactured by milling and grinding.

Nearly all cement clinker is produced in large rotary kiln systems. The rotary kiln is a refractory brick lined cylindrical steel shell equipped with an electrical drive to rotate it at 1-3 revolutions per minute, through which hot combustion gases flow counter-currently to the feed materials. The kiln can be fired with coal, oil, natural gas, waste (e.g., solvents) or a combination of these fuels. There are various types of kilns in use, including long wet kilns, long dry kilns, kilns with a preheater and kilns with a precalciner. The long wet and dry kilns and most preheater kilns have only one fuel combustion zone, whereas the newer precalciner kilns and preheater kilns with a riser duct have two fuel combustion zones.

In a wet kiln, the ground raw materials are suspended in water to form a slurry and introduced into the inlet feed. This kiln type employs no preheating of the dry feed. In a long dry kiln, the raw materials are dried to a powder and introduced into the inlet feed in a dry form, but this kiln type employs no preheating of the dry feed. Currently more cement plants use the dry process because of its lower energy requirement. In a precalciner kiln, the feed to the kiln system is preheated in cyclone chambers; the kiln uses a second burner to calcine material in a separate vessel attached to the preheater before the final fusion in a kiln that forms clinker.

Because the typical operating temperatures of these kilns differ, the NOx formation mechanisms also differ among these kiln types. In a primary combustion zone at the hot end of a kiln, the high temperatures lead to predominantly thermal NOx formation. In the secondary combustion zone, however, lower gas-phase temperatures suppress thermal NOx formation. The temperatures at which these kilns operate influence what NOx control technologies can be applied. For instance, SNCR can operate effectively at typical cement kiln temperatures (above 1500°F), while SCR typically operates effectively at lower temperatures (550-800°F). Energy efficiency is also important in reducing NOx emissions; for example, a high thermal efficiency equates to less heat and fuel being consumed and, therefore, less NOx is produced.

Portland cement is produced using a combination of variable inputs such as raw materials, labor, electricity, and fuel. U.S. Census data for the cement industry (North American Industry Classification System [NAICS] 32731: cement manufacturing) provides an initial overview of aggregated industry expenditures on these inputs (Department of Commerce [DOC], Bureau of the Census, 2021). In 2019, the total value of shipments was $9 billion, and the industry spent approximately $1.5 billion on materials, parts, and packaging, or 16.6% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to $1.4 billion (15.6%) and included 15,590 employees.

A review and description of market characteristics (i.e., degree of concentration, entry barriers, and product differentiation) can enhance our understanding of how U.S. cement markets operate. These characteristics provide indicators of a firm’s ability to influence market prices by varying the quantity of cement it sells. For example, in markets with large numbers of sellers and identical products, firms are unlikely to be able to influence market prices via their production decisions (i.e., they are “price takers”). However, in markets with few firms, significant barriers to entry (e.g., licenses, legal restrictions, or high fixed costs), or products that are similar but can be differentiated, the firm may have some degree of market power (i.e., set or significantly influence market prices).

Cement sales are often concentrated locally among a small number of firms for two reasons: high transportation costs and production economies of scale. Transportation costs significantly influence where cement is ultimately sold; high transportation costs relative to unit value provide incentives to produce and sell cement locally in regional markets (USITC, 2006). To support this claim, the empirical literature has typically pointed to Census of Transportation data showing over 80% of cement shipments were made within a 200-mile radius (Jans and Rosenbaum, 1997) and reported evidence of high transportation costs per dollar of product value from case studies (Ryan, 2006). The cement industry is also very capital intensive, and entry requires substantial investments. In addition, large plants are typically more economical because they can produce cement at lower unit costs; this reduces entry incentives for small sized cement plants and firms. EPA has recognized these aspects of the cement industry and its market structure in its economic impact analyses of rules on this industry in previous reports, such as the RIA prepared in 2010 for the portland cement NESHAP and NSPS (EPA, 2010).

### *2.4.2 Iron and Steel Mills and Ferroalloy Manufacturing*

Iron is produced from iron ore, and steel is produced by progressively removing impurities from iron ore or ferrous scrap. The first step is iron making. Primary inputs to the iron making process are iron ore or other sources of iron, coke or coal, and flux. Pig iron is the primary output of iron making and the primary input to the next step in the process, steel making. Metal scrap and flux are also used in steel making. The steel making process produces molten steel that is shaped into solid forms at forming mills. Finishing mills then shape, harden, and treat the semi-finished steel to yield its final marketable condition.

Steel often undergoes additional, referred to as secondary, metallurgical processes after it is removed from the steel making furnace. Secondary steel making takes place in vessels, smaller furnaces, or the ladle. These sites do not have to be as strong as the primary refining furnaces because they are not required to contain the powerful primary processes. Secondary steel making can have many purposes, such as removal of oxygen, sulfur, hydrogen, and other gases by exposing the steel to a low-pressure environment; removal of carbon monoxide through the use of deoxidizers such as aluminum, titanium, and silicon; and changing of the composition of unremovable substances such as oxides to further improve mechanical properties.

In 2019, the United States produced 87.8 million metric tons of steel (USGS, 2019). Steel is primarily used as a major input to consumer products such as automobiles and appliances. Therefore, the demand for steel is a derived demand that depends on a diverse base of consumer products. In addition, the Infrastructure Investment and Jobs Act, signed into law in 2021, will likely increase demand in both the iron and steel industry as well as the concrete and cement industry. The historic investment in roads, bridges, airports, and other physical infrastructure around the country will require large inputs from these industries.

U.S. Census data for the iron and steel industry (North American Industry Classification System [NAICS] 331110: Iron and steel mills and ferroalloy manufacturing) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was $93.7 billion, and the industry spent approximately $56.4 billion on materials, parts, and packaging, or 60% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to $10.1 billion (10.8%) and included 85,707 employees.

### *2.4.3 Glass and Glass Product Manufacturing*

Commercially produced glass can be classified as soda-lime, lead, fused silica, borosilicate, or 96 percent silica. Soda-lime glass consists of sand, limestone, soda ash, and cullet (broken glass). The manufacturing of such glass occurs in four phases: (1) preparation of raw material, (2) melting in the furnace, (3) forming and (4) finishing. The products of the glass manufacturing industry are flat glass, container glass, and pressed and blown glass. The procedures for manufacturing glass are the same for all products except forming and finishing. Container glass and pressed and blown glass use pressing, blowing, or pressing and blowing to form the desired product. Flat glass, which is the remainder, is formed by float, drawing, or rolling processes.

As the sand, limestone, and soda ash raw materials are received, they are crushed and stored in separate elevated bins. These materials are then transferred through a gravity feed system to a weigher and mixer, where the material is mixed with cullet to ensure homogeneous melting. The mixture is conveyed to a batch storage bin where it is held until dropped into the feeder to the glass melting furnace. All equipment used in handling and preparing the raw material is housed separately from the furnace and is usually referred to as a batch plant.

The glass melting furnaces contribute to most of the total emissions from the glass plant. Essentially all the NOx emissions associated with glass manufacturing are generated in the melting furnaces due to the high process temperatures. These materials are then heated in the furnace to temperatures around 3000°F to induce fusion that produces molten glass. After molten glass is produced, it then goes to be shaped by pressing, blowing, pressing and blowing, drawing, rolling, or floating to produce the desired product. The end products undergo finishing (decorating or coating) and annealing (removing unwanted stress area in the glass) as required. During the inspection process, any damaged or undesirable glass is transferred back to the batch plant to be used as cullet.

Glass manufacturing furnaces can vary between the various categories of glass produced (container, flat, or pressed/blown). This is because the different types of glass vary in composition and quality specifications. Therefore, each type of glass produced requires different energy inputs to fuse the raw materials. As a result, the emissions from similar furnaces producing different types of glass can vary significantly. Furnaces can also be fired with gaseous or liquid fuels.

U.S. Census data for the glass manufacturing industry (North American Industry Classification System [NAICS] 32721) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was $27.6 billion, and the industry spent approximately $10.9 billion on materials, parts, and packaging, or 40% of the value of shipments. Total compensation for all employees (includes payroll and fringe benefits) amounted to $5.3 billion and included 91,988 employees.

### *2.4.4 Pipeline Transportation of Natural Gas*

This industry comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems. This industry includes the storage of natural gas because the storage is usually done by the pipeline establishment and because a pipeline is inherently a network in which all the nodes are interdependent.

U.S. Census data for the pipeline transportation of natural gas industry (North American Industry Classification System [NAICS] 486210) provides an initial overview of aggregated industry expenditures on these inputs (Census Bureau, 2021). In 2019, the total value of shipments was $27.6 billion, annual payroll totaled $3.3 billion, and the industry included 27,294 employees.

*2.4.5 Industrial Boilers*

This rulemaking includes $NO_x$ emission limits on boilers from an additional five industries. One of those industries is Iron and Steel Mills and Ferroalloy Manufacturing, which was discussed above; the remaining four industries are discussed briefly below.

This first industry is Metal Ore Mining. Taconite, the principal iron ore mined in the United States, has a low (20 percent to 30 percent) iron (Fe) content and is found in hard, fine-grained, banded iron formations. The main taconite iron ore deposits are located near Lake Superior in Minnesota (Mesabi Iron Range) and Michigan (Marquette Iron Range). The taconite mining operations in Michigan and Minnesota accounted for virtually all domestic iron ore production (Kirk, 1999).

The next industry is the pulp, paper, and paperboard mills industry. Manufacturing of paper and paper products is a complex process that is carried out in two distinct phases: the pulping of wood and the manufacture of paper. Pulping is the conversion of fibrous wood into a "pulp" material suitable for use in paper, paperboard, and building materials. Pulping and papermaking may be integrated at the same production facility, or facilities may produce either pulp or paper alone. In addition to facilities that produce pulp and/or paper, there are numerous establishments that do not manufacture paper, but convert paper into secondary products.

Steam boilers are pivotal in the paper industry for the process of drying the paper, energy requirement, and the cooking of wood chips in the digester. The steam is used for cooking wood chips, dryer cans, and to produce power for the plant. Power can be produced through the combustion of bark, black liquor, and fuel oil to reduce the cost with large electric demand and increase reliability versus outside power sources. Firms engaged in pulp and paper manufacturing under the North American Industry Classification System (NAICS) code 3221. In 2019, the pulp and paper industry shipped products valued at over $76 billion and included 92,283 employees (U.S. Census Bureau, 2021). This industry has declined in the United States with a 22% decrease in the number of establishments and a 42% decrease in the number of employees from 2000 to 2019.

The next industry is the petroleum and coal products manufacturing industry. The impacted boilers in this industry come from petroleum refineries. Petroleum pumped directly out of the ground, or crude oil, is a complex mixture of hydrocarbons (chemical compounds that consist solely of hydrogen and carbon) and various impurities, such as salt. To manufacture the variety of petroleum products recognized in everyday life, this complex mixture must be refined and processed over several stages. Boilers are used for several functions in a petroleum refining facility. The steam generated from the boiler can be used to power turbines and pumps or for heating of facilities and processes. Large refineries use lots of steam to heat crude oil during the distillation process.

The process of refining crude oil into useful petroleum products can be separated into two phases and a number of supporting operations. In the first phase, crude oil is desalted and then separated into its various hydrocarbon components (known as "fractions"). These fractions include gasoline, kerosene, naphtha, and other products. In the second phase, the distilled fractions are converted into petroleum products (such as gasoline and kerosene) using three different types of downstream processes: combining, breaking, and reshaping (EPA, 1995).

The petroleum refining industry is comprised of establishments primarily engaged in refining crude petroleum into finished petroleum products. Examples of these products include gasoline, jet fuel, kerosene, asphalt, lubricants, and solvents.  Firms engaged in petroleum refining are categorized under the North American Industry Classification System (NAICS) code 324110. In 2019, the petroleum refining industry shipped products valued at over $547 billion and included 63,659 employees (U.S. Census Bureau, 2021).

The fourth industry is basic chemical manufacturing, which includes establishments primarily engaged in manufacturing chemicals using basic processes, such as thermal cracking and distillation. Chemicals manufactured in this industry group are usually separate chemical elements or separate chemically-defined compounds.

The chemicals industry is one of the most complex and diverse industries in the U.S., and simple characterizations are impossible. While the EIA Manufacturing Energy Consumption Survey (MECS) identifies 10 significant steam-consuming product categories within the chemical industry, it identifies only nine for the food, paper, refining and primary metals industries, combined. The major steam consuming processes in the chemical industry include stripping, fractionalization, power generation, mechanical drive, quenching and dilution.

U.S. Census data for the basic chemical manufacturing industry (North American Industry Classification System [NAICS] 3251) provides an initial overview of aggregated industry expenditures. In 2019, the value of shipments for the industry was $206 billion and included 143,000 employees (U.S. Census Bureau, 2021).

#### *2.4.6 Municipal Waste Combustors*

Municipal solid waste (MSW) combustion is the process of reducing the volume of MSW through incineration (combustion). Because combustion reduces waste volume by as much as 90 percent, this method of waste management has the potential to significantly reduce the need for landfills. Combustion has two principal functions—MSW volume reduction and energy generation—and produces residual products of ash and emissions to the ambient air. The inputs are capital services (e.g., combustor unit, land, building, air pollution control devices), operating services (e.g., labor services, maintenance services, fuel for startup, utility services), and MSW.

Municipal waste combustors (MWCs) can be classified according to three principal types: mass burn (MB), modular (MOD), and refuse-derived fuel (RDF) combustors. Variations exist within these categories, and some designs incorporate features of more than one type. Regardless of the technology, each MWC plant site or facility has at least one, and potentially more than one, individual combustor unit. Typically, an MWC plant has two or three units on site.

The U.S. Economic Census (U.S. Bureau of the Census) classifies affected MWCs in a category called solid waste combustors and incinerators (NAICS 562213). Between 2012 and 2017 the industry declined from 109 establishments and $2.5 billion in sales to 61 establishments and $1.3 billion in sales (U.S. Census Bureau, 2021). In 2020 the industry consisted of 60 establishments, an annual payroll of $191 million, and 1,803 employees (U.S. Census Bureau, 2021).

### 2.5 References

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## CHAPTER 3: AIR QUALITY IMPACTS

### Overview

This chapter presents the impacts on ozone concentrations in 2023 and ozone and $PM_{2.5}$ in 2026 from emissions reductions associated with the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative) analyzed in this RIA.[51] Specifically, for 2023 we analyzed the impacts of ozone season (i.e., May through September) $NO_X$ emissions reductions from EGUs on April through September average Maximum Daily Average 8-hour ozone concentrations (AS-MO3) for each of the three control alternatives. For 2026[52] we analyzed the impacts on AS-MO3 from ozone season $NO_X$ emissions reductions from EGUs and from non-EGU separately and combined for each of the three alternatives. In addition, for 2026 we also analyzed the impacts on annual average $PM_{2.5}$ concentrations from the changes in EGU emissions of $NO_X$, $SO_2$, and directly emitted $PM_{2.5}$ outside of the ozone season that are expected to result from certain EGU NOx controls that are expected to operate year-round and generation shifting in response to the implementation of EGU controls in the three regulatory control alternatives (see Chapter 4).[53]

In this chapter we first describe the methods for developing spatial fields of air quality concentrations[54] for the baseline and regulatory control alternatives in 2023 and 2026. These spatial fields provide the air quality data that are used in the environment justice (EJ) analysis and the analysis of health benefits from reduced concentrations of ozone and $PM_{2.5}$ that are expected to result from this final rule. In brief, the spatial fields are constructed based on a method that utilizes 2026 baseline ozone and $PM_{2.5}$ contributions from emissions in individual states, state-level emissions for the baseline and each of the regulatory control alternatives, along

[51] The 2023 and 2026 baseline and regulatory controls alternatives are described in Chapter 4.

[52] The baseline EGU emissions and emissions reductions from the three EGU regulatory control alternatives that were used to create spatial fields for 2026 align with the 2025 EGU baseline and control alternatives emissions described in Chapter 4.

[53] The approach for creating spatial fields of annual average $PM_{2.5}$ concentrations is not capable of handling emissions reductions that vary by season. In this regard, our impact analysis for annual average $PM_{2.5}$ does not include NOx emissions reductions during the ozone season. Excluding ozone season NOx reductions is not expected to bias the annual impacts because NOx emissions primarily affect concentrations of PM nitrate, which is a secondary pollutant that is formed during the cooler months of the year with near zero concentrations measured during the summer. Similarly, we do not include the impacts of non-EGU NOx reductions on annual average $PM_{2.5}$ because the non-EGU emissions limits are only required to operate during the ozone season.

[54] Spatial fields are comprised of gridded pollutant concentration and contribution data at 12 km resolution covering the portion of the U.S. within the air quality modeling domain.

with baseline spatial fields of ozone and $PM_{2.5}$ concentrations. The basic methodology for determining air quality changes for this final rule are the same as those used in the proposal RIA and in RIAs for multiple previous rules (U.S. EPA, 2019; U.S. EPA, 2020a; U.S. EPA, 2020b; U.S. EPA, 2021).

In Section 3.1 we describe the air quality modeling platform; in Section 3.2 we describe the method for processing air quality modeling outputs to create spatial fields; in Section 3.3 we describe how this method was applied for the analyses in this RIA; in Section 3.4 we present maps showing the impacts on AS-MO3 and annual $PM_{2.5}$ for each of the regulatory control alternatives compared to the corresponding baseline; and in Section 3.5 we identify uncertainties and limitations in the application of the method for generating spatial fields of pollutant concentrations.

In Appendix 3A, we provide the estimated impacts on projected 2026 ozone design values that are expected to result from the emissions reductions from the combined EGU and non-EGU final rule case. The impacts on design values are based on air quality modeling of the 2026 final rule baseline and the 2026 final rule.

## 3.1 Air Quality Modeling Platform

The EPA used photochemical air quality modeling as part of the process to create spatial fields that reflect the influence of emissions changes between the baseline and each of the regulatory control alternatives in each year, as applicable, for this final rule RIA. The model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10[55] (Ramboll Environ, 2021). The nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12×12 km, as shown in Figure 3-1. Model predictions were evaluated by comparing predictions of base year 2016 ozone and $PM_{2.5}$ concentrations to ambient measurements (U.S. EPA, 2022a; 2022b). Ozone and $PM_{2.5}$ model evaluations showed model performance that was comparable to other contemporaneous model applications and, therefore, deemed adequate for the purpose of creating spatial fields for the purposes of this RIA.

[55] This CAMx simulation set the Rscale $NH_3$ dry deposition parameter to 0, which resulted in more realistic model predictions of $PM_{2.5}$ nitrate concentrations than using a default Rscale parameter of 1.


**Figure 3-1 Air Quality Modeling Domain**

As noted above, the process for creating spatial fields utilized ozone and $PM_{2.5}$ concentrations as well as the contributions from EGU and non-EGU emissions in individual states. The contributions to assess the impacts on AS-MO3 for the final rule are the same as those used for the proposed rule. That is, for this final rule analysis we used the 2026 ozone concentrations and corresponding EGU and non-EGU contribution predictions from the 2016 version 2 (i.e., 2016v2) emissions platform that was developed and used for proposal.[56] In the proposal RIA, we relied on benefit per ton estimates to compute the benefits expected from reductions in annual average $PM_{2.5}$ concentrations. For this final rule we conducted $PM_{2.5}$ state-by-state source apportionment air quality modeling to quantify contributions to annual $PM_{2.5}$ from EGU emissions of $NO_X$, $SO_2$, and directly emitted $PM_{2.5}$ in 2026. The data from this modeling were used to develop spatial fields of annual average $PM_{2.5}$ for the 2026 baseline and each of the three EGU regulatory control alternatives in that year. In order to provide consistency between the analyses for ozone and the analyses for $PM_{2.5}$, the source apportionment modeling for $PM_{2.5}$ was performed using the same inputs and model configuration as we used for the ozone source apportionment modeling performed for the proposed rule analysis.

[56] The 2016v2 emissions platform includes emissions data for 2016, 2023, 2026, and 2032. For the final rule, the EPA developed a version 3 (v3) emissions inventory, which reflects updates based largely on comments on the proposal. As described in the text, for this final rule RIA, we use the v2 modeling in a relative sense coupled with the v3 emissions to create spatial fields for the final rule 2023 and 2026 baseline scenarios and the regulatory control alternatives.

The contributions to ozone and $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[57]) were modeled using the source apportionment tools in CAMx. Ozone contributions were modeled using the Anthropogenic Precursor Culpability Assessment (APCA) tool and $PM_{2.5}$ contributions were modeled using the Particulate Matter Source Apportionment Technology (PSAT) tool (Ramboll, 2021). In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags."[58] These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[59] contributions from the emissions in each individual tag to hourly gridded modeled concentrations. For this RIA we used the source apportionment contribution data to provide a means to estimate the effect of changes in emissions from each group of emissions sources (i.e., each tag) to changes in ozone and $PM_{2.5}$ concentrations. Specifically, we applied outputs from the 2026 baseline state-by-state EGU and non-EGU source apportionment modeling to obtain the contributions from EGU and non-EGU emissions in each state to concentrations and the contributions in each 12 x 12 km model grid cell nationwide. The ozone source apportionment modeling was performed for the period April through September to provide data for developing spatial fields for the April through September AS-MO3 ozone exposure metric. The $PM_{2.5}$ source apportionment modeling was performed for a full year to provide data for developing spatial fields of annual average $PM_{2.5}$.

## 3.2 Applying Modeling Outputs to Create Spatial Fields

In this section we describe the method for creating spatial fields of AS-MO3 and annual average $PM_{2.5}$ based on the air quality modeling for 2016v2 and 2026v2. The foundational data include (1) ozone and speciated $PM_{2.5}$ concentrations in each model grid cell from the 2016 and 2026 v2 modeling, (2) ozone contributions in 2026v2 from EGU and non-EGU ozone season emissions in each state and speciated $PM_{2.5}$ contributions in 2026v2 from annual EGU emissions in each state in each model grid cell, (3) 2026v2 emissions from EGUs and non-EGUs that were

[57] Crustal material refers to elements that are commonly found in the earth's crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium and the associated oxygen atoms.
[58] Each state was treated as a separate source tag. Note that point source (EGU and non-EGU) sources on tribal lands were assigned to a national "tribal land" tag.
[59] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.

inputs to the contribution modeling, and (4) the EGU and non-EGU v3 emissions from the final rule 2023 and 2026 baseline scenarios and each of the three regulatory control alternatives in 2023 and 2026.

The method to create spatial fields applies scaling factors to gridded source apportionment contributions based on emissions changes between the 2026v2 baseline and the 2023v3 and 2026v3 baseline and regulatory control alternatives. This method is described in detail below.

Spatial fields of ozone and $PM_{2.5}$ in 2026 were created based on “fusing” modeled data with measured concentrations at air quality monitoring locations. To create the spatial fields for each future emissions scenario these fused model fields are used in combination with 2026 state-EGU and non-EGU source apportionment modeling and the EGU and non-EGU emissions for each regulatory control alternative and analytic year, as applicable. Contributions from each contribution “tag” were scaled based on the ratio of emissions in the year/alternative being evaluated to the emissions in the modeled 2026 scenario. Contributions from tags representing sources other than EGUs and non-EGUs are held constant at 2026 levels for each of the alternatives and year. For each alternative and year analyzed, the scaled contributions from all sources were summed together to create a gridded surface of total modeled ozone and $PM_{2.5}$. The process is described in a step-by-step manner below. For ozone, the process for creating spatial fields of AS-MO3 concentrations is explained using an EGU control case as an illustrative example. This process was performed to create AS-MO3 spatial fields for the 2023 and 2026 baselines and for the EGU and non-EGU regulatory control alternatives analyzed for this final rule RIA. For annual $PM_{2.5}$, we describe the steps for creating spatial fields for the 2026 baseline and EGU regulatory control alternatives.

### *3.2.1 Spatial Distribution of Ozone Impacts*

When interpreting the spatial fields of AS-MO3 it is important to recognize that ozone is a secondary pollutant, meaning that it is formed through chemical reactions of precursor emissions in the atmosphere. As a result of the time necessary for precursors to mix in the atmosphere and for these reactions to occur, ozone can either be highest at the location of the precursor emissions or peak at some distance downwind of those emissions sources. The spatial gradients of ozone depend on a multitude of factors including the spatial patterns of $NO_X$ and

VOC emissions and the meteorological conditions on a particular day. Thus, on any individual day, high ozone concentrations may be found in narrow plumes downwind of specific point sources, may appear as urban outflow with large concentrations downwind of urban source locations or may have a more regional signal. However, in general, because the AS-MO3 metric is based on the average of concentrations over more than 180 days in the spring and summer, the resulting spatial fields are rather smooth without sharp gradients, compared to what might be expected when looking at the spatial patterns of maximum daily 8-hour average (MDA8) ozone concentrations on specific high ozone episode days.

The impacts of the regulatory control alternatives for EGUs in 2023 and 2026 on ozone season EGU NOx emissions for all states are provided in Table 3-1.[60] The impacts of the regulatory control alternatives for non-EGUs in 2026 on ozone season non-EGU NOx emissions by state are provided in Table 3-2. Note that negative values in Tables 3-1 and 3-2 denote a reduction in emissions and positive values denote an increase in emissions.[61] The spatial fields of baseline AS-MO3 in 2023 and 2026 are presented in Figure 3-2 and Figure , respectively. The distribution of AS-MO3 baseline concentrations in 2023 and 2026 are similar, but the concentrations are somewhat lower in 2026, as is expected due to emissions reductions resulting from continued implementation of existing "on-the-books" rules and regulations. The figures show that, from a regional perspective, the highest AS-MO3 concentrations are in the inter-mountain and southwest portions of the western U.S. where contributions from background sources are dominant outside of urban areas, and in southern and central California where there are high emissions of ozone precursor pollutants. Within the eastern U.S. the highest concentrations are seen in the Ohio Valley and portions of the Midwest, as well as along the Northeast Corridor and near urban areas such as Atlanta and Houston.

[60] Emission reductions at sources on tribal lands are included in the tribal lands categories all of the emissions tables in this chapter.
[61] The imposition of the final rule results in changes in regional electricity flows, resulting in changes in net imports. As a result, some states (even those not subject to the rule) may see changes in emissions as a result of generation shifting.

**Table 3-1. Impact on EGU Ozone Season NOx Emissions of each Regulatory Control Alternative in 2023 and in 2026 (1,000 tons)**

| State | 2023 EGU Ozone Season $NO_X$ Emissions | | | 2026 EGU Ozone Season $NO_X$ Emissions | | |
|---|---|---|---|---|---|---|
| | Final – Baseline | Less Stringent – Baseline | More Stringent – Baseline | Final – Baseline | Less Stringent – Baseline | More Stringent – Baseline |
| Alabama | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 |
| Arizona | 0.0 | 0.0 | 0.0 | -0.3 | 0.0 | 0.5 |
| Arkansas | -0.3 | -0.3 | -0.3 | -5.7 | -0.4 | -7.0 |
| California | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 |
| Colorado | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 |
| Connecticut | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Delaware | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| District of Columbia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Florida | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Georgia | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.6 |
| Idaho | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 |
| Illinois | -0.1 | -0.1 | -0.1 | 0.3 | 0.0 | 0.9 |
| Indiana | -0.1 | -0.1 | -0.1 | -1.1 | 0.1 | -2.0 |
| Iowa | 0.0 | 0.0 | 0.0 | 0.3 | -0.1 | -0.1 |
| Kansas | 0.0 | 0.0 | 0.0 | 0.4 | 0.0 | 1.0 |
| Kentucky | -0.8 | -0.8 | -1.1 | -2.3 | -0.6 | -6.0 |
| Louisiana | -0.3 | -0.3 | -0.3 | -4.0 | -1.7 | -4.0 |
| Maine | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Maryland | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Massachusetts | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Michigan | 0.0 | 0.0 | 0.0 | -2.1 | 0.1 | -3.4 |
| Minnesota | -1.0 | -1.0 | -1.0 | -1.2 | -1.2 | -1.2 |
| Mississippi | -1.0 | -1.0 | -1.0 | -0.1 | -0.2 | 0.0 |
| Missouri | -1.8 | -1.8 | -1.8 | -4.8 | -1.8 | -6.3 |
| Montana | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Nebraska | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 |
| Nevada | -0.5 | -0.5 | -0.5 | 0.0 | 0.0 | 0.0 |
| New Hampshire | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| New Jersey | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 | -0.1 |
| New Mexico | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| New York | -0.2 | -0.2 | -0.2 | -0.2 | -0.2 | -0.1 |
| North Carolina | 0.0 | 0.0 | -0.1 | 0.4 | 0.0 | 0.3 |
| North Dakota | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 |

| State | 2023 EGU Ozone Season $NO_X$ Emissions | | | | 2026 EGU Ozone Season $NO_X$ Emissions | | |
|---|---|---|---|---|---|---|---|
| | **Final – Baseline** | **Less Stringent – Baseline** | **More Stringent – Baseline** | | **Final – Baseline** | **Less Stringent – Baseline** | **More Stringent – Baseline** |
| Ohio | -0.2 | -0.2 | -0.2 | | -1.5 | -1.5 | -1.5 |
| Oklahoma | -1.4 | -1.4 | -1.4 | | -2.2 | -1.3 | -4.4 |
| Oregon | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Pennsylvania | 0.0 | -0.1 | 0.0 | | 0.1 | -0.1 | 0.0 |
| Rhode Island | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| South Carolina | 0.0 | 0.0 | 0.0 | | 0.2 | 0.1 | 0.0 |
| South Dakota | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Tennessee | 0.0 | 0.0 | 0.0 | | 0.0 | -0.1 | 0.6 |
| Texas | -1.2 | -1.2 | -1.2 | | -1.1 | -1.3 | -14.3 |
| Utah | -1.5 | -1.5 | -1.5 | | -4.8 | -0.1 | -5.9 |
| Vermont | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Virginia | 0.0 | 0.0 | 0.0 | | 0.2 | 0.0 | -0.2 |
| Washington | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| West Virginia | 1.2 | 1.2 | 1.3 | | -1.7 | 1.0 | -2.9 |
| Wisconsin | -0.4 | -0.4 | -0.4 | | 0.1 | 0.0 | 0.0 |
| Wyoming | 0.0 | 0.0 | 0.0 | | 0.5 | -0.5 | 0.8 |
| Tribal Lands | 0.0 | 0.0 | 0.0 | | -1.3 | 0.0 | -1.3 |
| Nationwide | -9.9 | -9.8 | -10.0 | | -31.8 | -9.9 | -56.0 |

**Table 3-2. Impact on Non-EGU Ozone Season NOx Emissions of each Regulatory Control Alternative in 2026 (1,000 tons)**

| State | 2026 Non-EGU Ozone Season $NO_X$ Emissions | | |
|---|---|---|---|
| | **Policy – Baseline** | **Less Stringent – Baseline** | **More Stringent – Baseline** |
| Alabama | 0.0 | 0.0 | 0.0 |
| Arizona | 0.0 | 0.0 | 0.0 |
| Arkansas | -1.6 | -0.5 | -1.7 |
| California | -1.6 | -1.5 | -4.5 |
| Colorado | 0.0 | 0.0 | 0.0 |
| Connecticut | 0.0 | 0.0 | 0.0 |
| Delaware | 0.0 | 0.0 | 0.0 |
| District of Columbia | 0.0 | 0.0 | 0.0 |
| Florida | 0.0 | 0.0 | 0.0 |

| State | 2026 Non-EGU Ozone Season $NO_X$ Emissions | | |
|---|---|---|---|
| | Policy – Baseline | Less Stringent – Baseline | More Stringent – Baseline |
| Georgia | 0.0 | 0.0 | 0.0 |
| Idaho | 0.0 | 0.0 | 0.0 |
| Illinois | -2.4 | -0.8 | -3.1 |
| Indiana | -2.0 | -1.4 | -3.5 |
| Iowa | 0.0 | 0.0 | 0.0 |
| Kansas | 0.0 | 0.0 | 0.0 |
| Kentucky | -3.0 | -0.7 | -3.5 |
| Louisiana | -8.5 | -2.2 | -9.2 |
| Maine | 0.0 | 0.0 | 0.0 |
| Maryland | -0.1 | -0.1 | -1.1 |
| Massachusetts | 0.0 | 0.0 | 0.0 |
| Michigan | -3.2 | -0.8 | -5.4 |
| Minnesota | 0.0 | 0.0 | 0.0 |
| Mississippi | -2.9 | -0.6 | -3.1 |
| Missouri | -2.1 | -0.6 | -4.8 |
| Montana | 0.0 | 0.0 | 0.0 |
| Nebraska | 0.0 | 0.0 | 0.0 |
| Nevada | 0.0 | 0.0 | 0.0 |
| New Hampshire | 0.0 | 0.0 | 0.0 |
| New Jersey | -0.2 | -0.2 | -0.3 |
| New Mexico | 0.0 | 0.0 | 0.0 |
| New York | -1.0 | -0.7 | -1.5 |
| North Carolina | 0.0 | 0.0 | 0.0 |
| North Dakota | 0.0 | 0.0 | 0.0 |
| Ohio | -3.4 | -1.1 | -4.3 |
| Oklahoma | -7.7 | -2.4 | -9.3 |
| Oregon | 0.0 | 0.0 | 0.0 |
| Pennsylvania | -2.3 | -1.7 | -4.7 |
| Rhode Island | 0.0 | 0.0 | 0.0 |
| South Carolina | 0.0 | 0.0 | 0.0 |
| South Dakota | 0.0 | 0.0 | 0.0 |
| Tennessee | 0.0 | 0.0 | 0.0 |
| Texas | -6.6 | -2.7 | -14.1 |
| Utah | -0.4 | -0.1 | -1.0 |
| Vermont | 0.0 | 0.0 | 0.0 |
| Virginia | -1.8 | -0.8 | -2.2 |

| State | 2026 Non-EGU Ozone Season $NO_X$ Emissions | | |
|---|---|---|---|
| | Policy – Baseline | Less Stringent – Baseline | More Stringent – Baseline |
| Washington | 0.0 | 0.0 | 0.0 |
| West Virginia | -2.0 | -0.5 | -2.5 |
| Wisconsin | 0.0 | 0.0 | 0.0 |
| Wyoming | 0.0 | 0.0 | 0.0 |
| Tribal Lands | 0.0 | 0.0 | 0.0 |
| Nationwide | -52.9 | -19.4 | -79.7 |

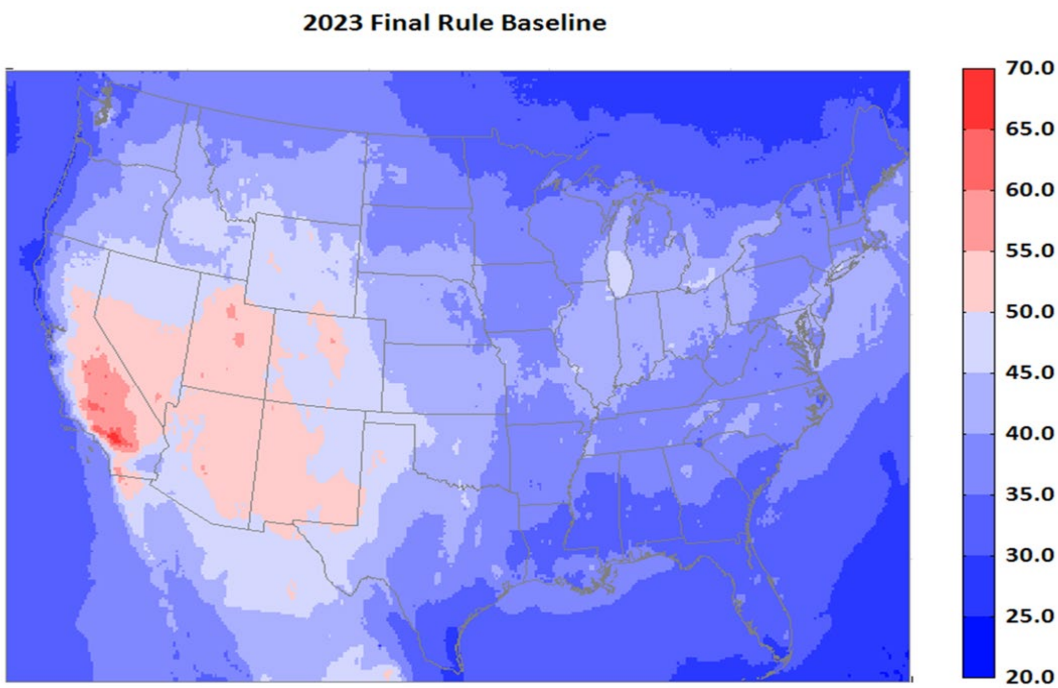


**Figure 3-2. 2023 Baseline AS-MO3 Concentrations (ppb)**

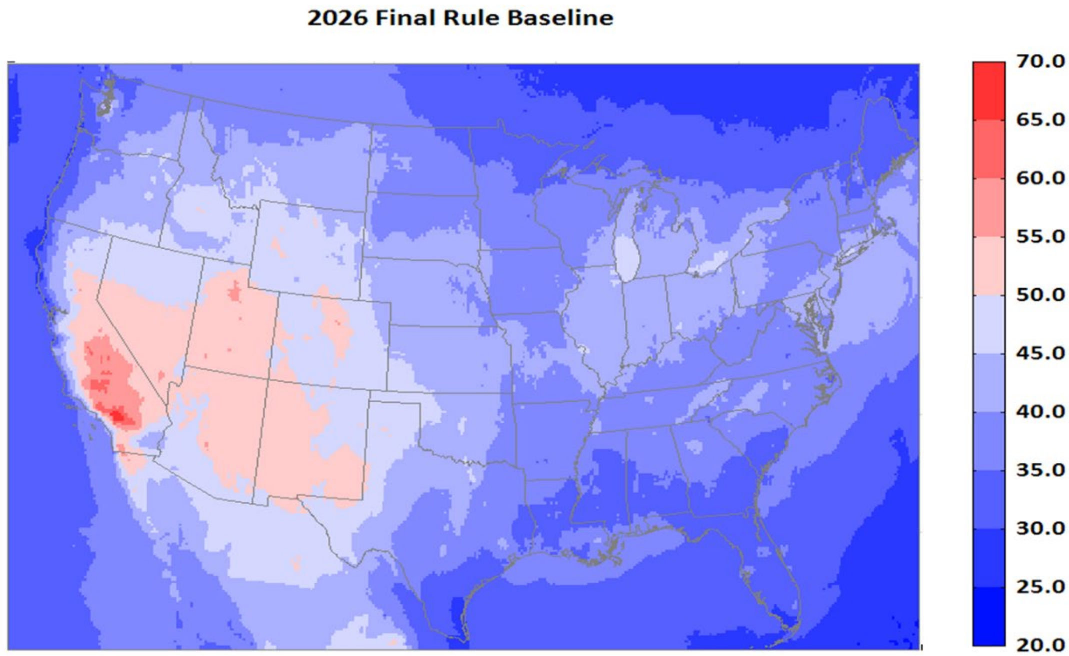


**Figure 3-3. 2026 Baseline AS-MO3 Concentration (ppb)**

The estimated impacts on AS-MO3 between the baseline and each of the regulatory control alternatives for 2023 and 2026 are presented in Figure 3-4 through Figure 3-15. The ppb differences shown in Figures 3-4 through 3-15 are calculated as the regulatory control alternative minus the baseline (i.e., negative values indicate reductions in pollutant concentrations). Note that the scale for the impacts of the more stringent alternative in 2026, as shown in Figure 3-15, is larger than the scale used to display the impacts for the less stringent alternative and final rule alternatives in Figures 3-13 and 3-14, respectively.

The spatial patterns of the impacts of emissions reductions are a result of (1) the location of EGU and non-EGU sources with reduced ozone season $NO_X$ emissions between the baseline and the corresponding regulatory control alternatives and (2) the physical or chemical processing that the model simulates in the atmosphere. In this respect, ozone reductions are greatest in proximity to the affected sources with regional impacts in areas further downwind from these sources. Increases in ozone concentrations in parts of West Virginia seen in the 2023 regulatory control alternatives reflect the increase in ozone season EGU $NO_X$ emissions in this state, as indicated in Table 3-1.

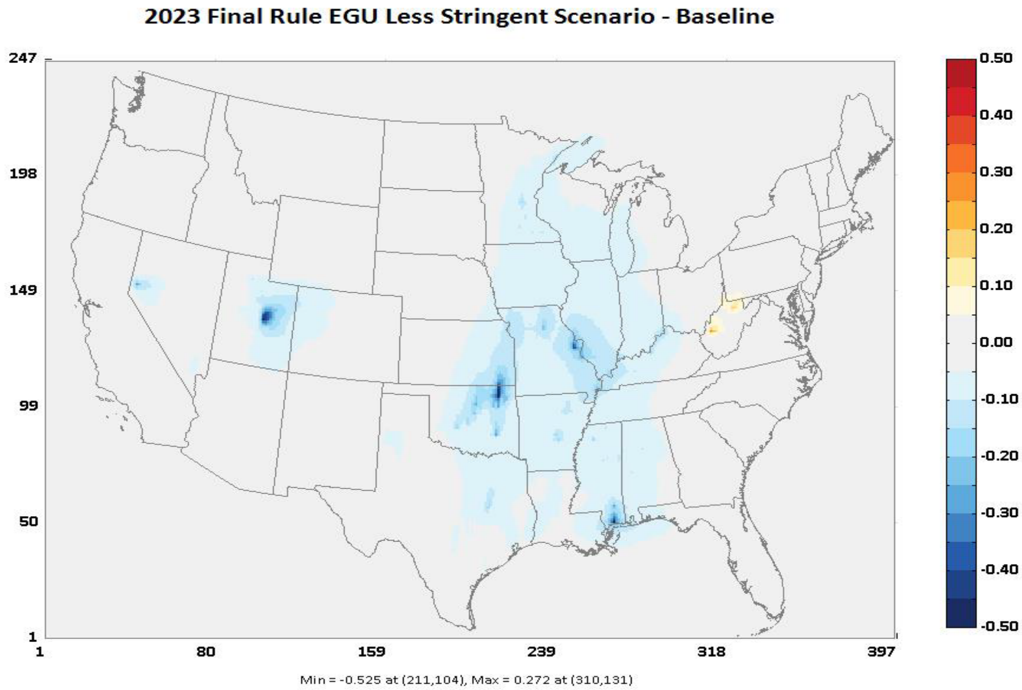


**Figure 3-4. Reduction in AS-MO3 (ppb): 2023 Less Stringent EGU-only Alternative vs the 2023 Baseline (scale: $\pm$ 0.5 ppb)**

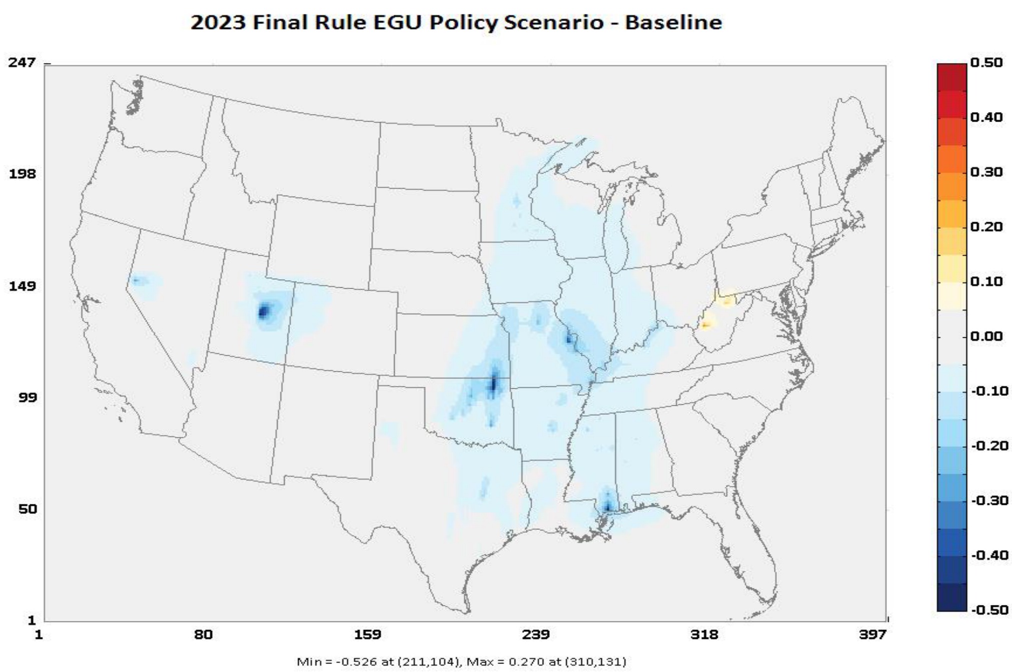


**Figure 3-5. Reduction in AS-MO3 (ppb): 2023 Final Rule EGU-only Alternative vs the 2023 Baseline (scale: $\pm$ 0.5 ppb)**

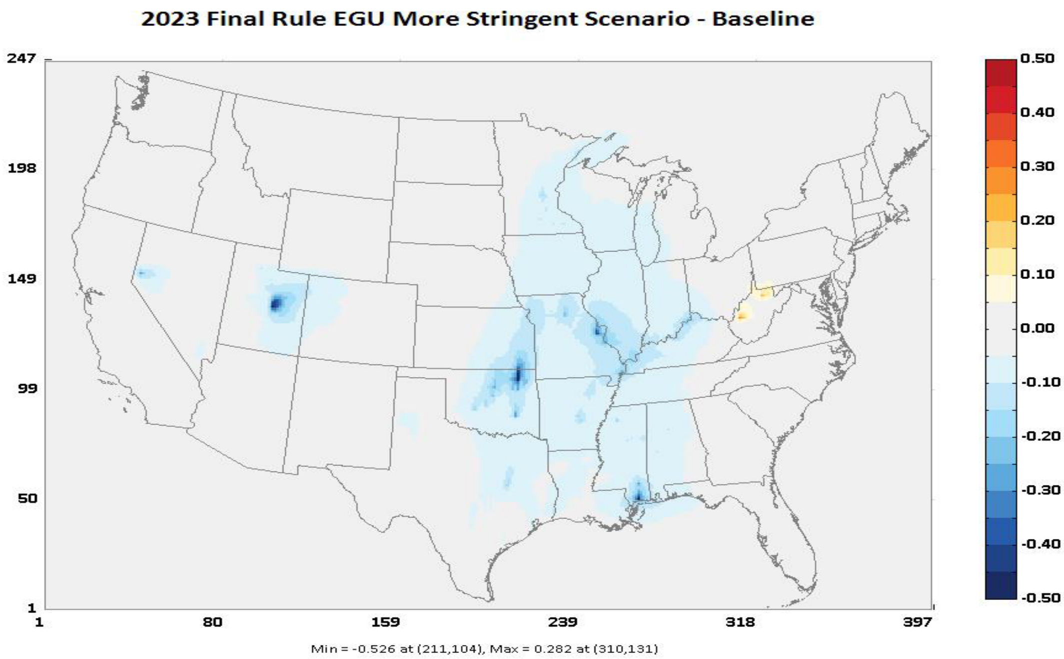


**Figure 3-6. Reduction in AS-MO3 (ppb): 2023 More Stringent EGU-only Alternative vs the 2023 Baseline (scale: ± 0.5 ppb)**

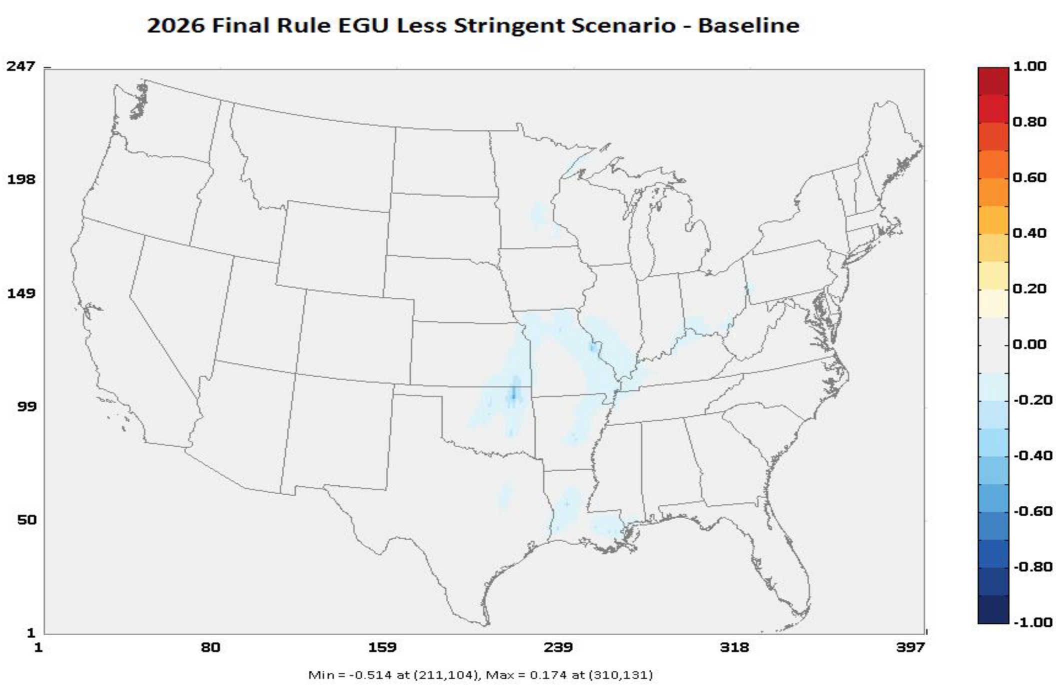


**Figure 3-7. Reduction in AS-MO3 (ppb): 2026 Less Stringent EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

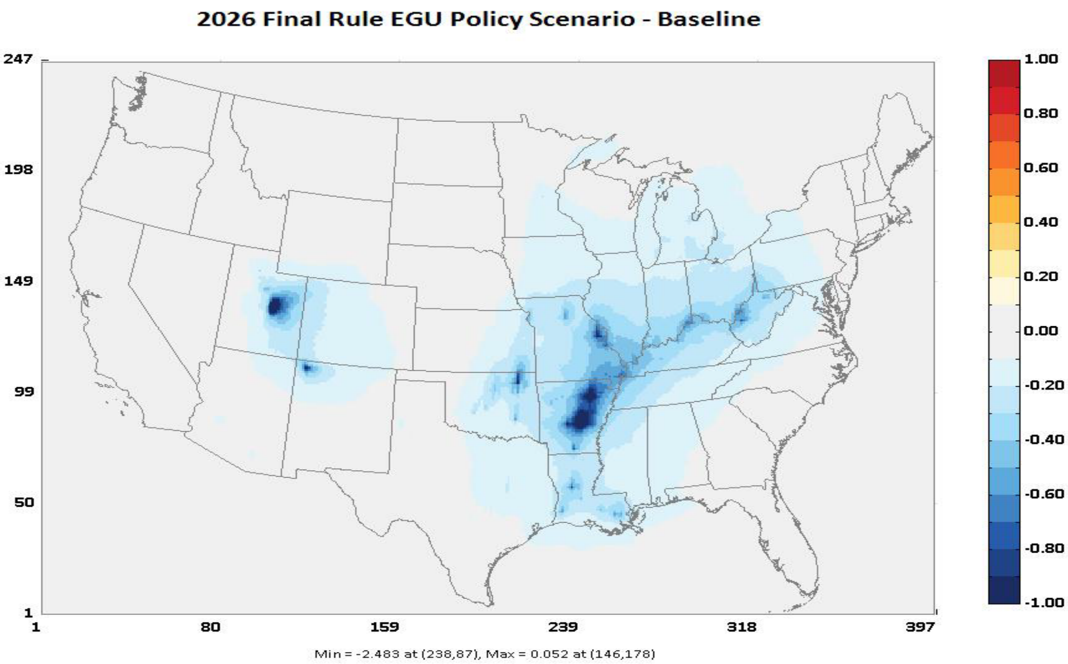


**Figure 3-8. Reduction in AS-MO3 (ppb): 2026 Final Rule EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

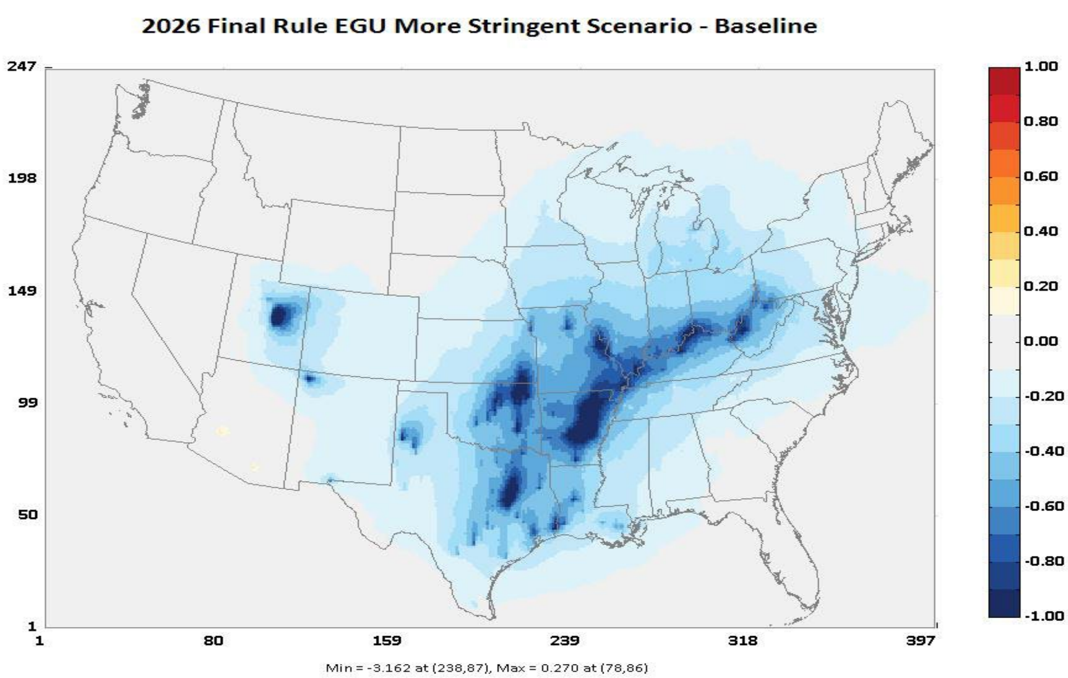


**Figure 3-9. Reduction in AS-MO3 (ppb): 2026 More Stringent EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

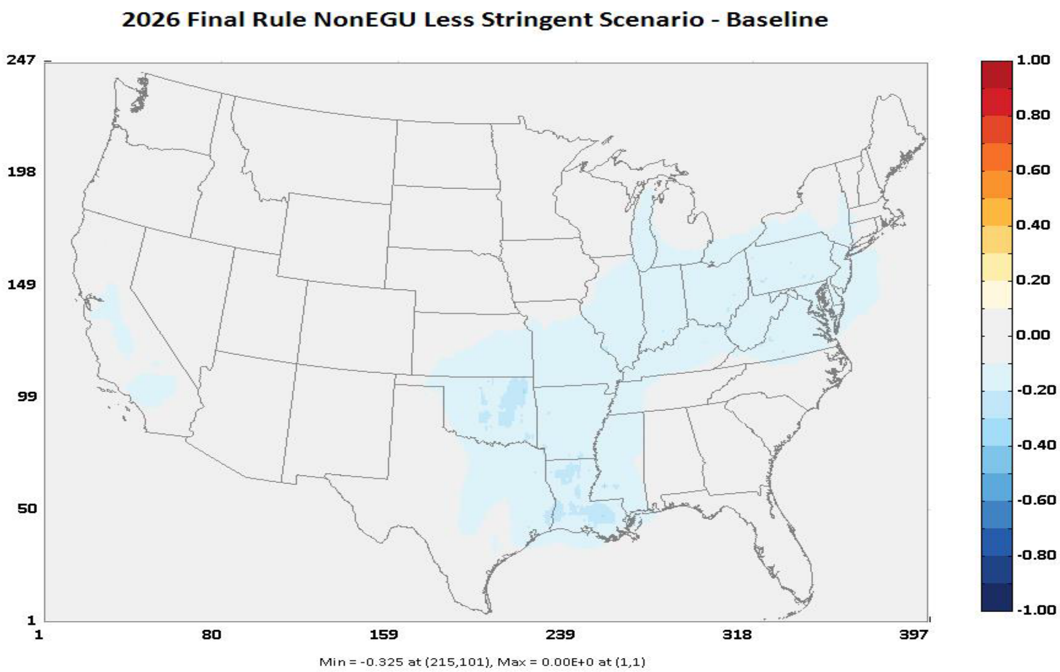


**Figure 3-10. Reduction in AS-MO3 (ppb): 2026 Less Stringent non-EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

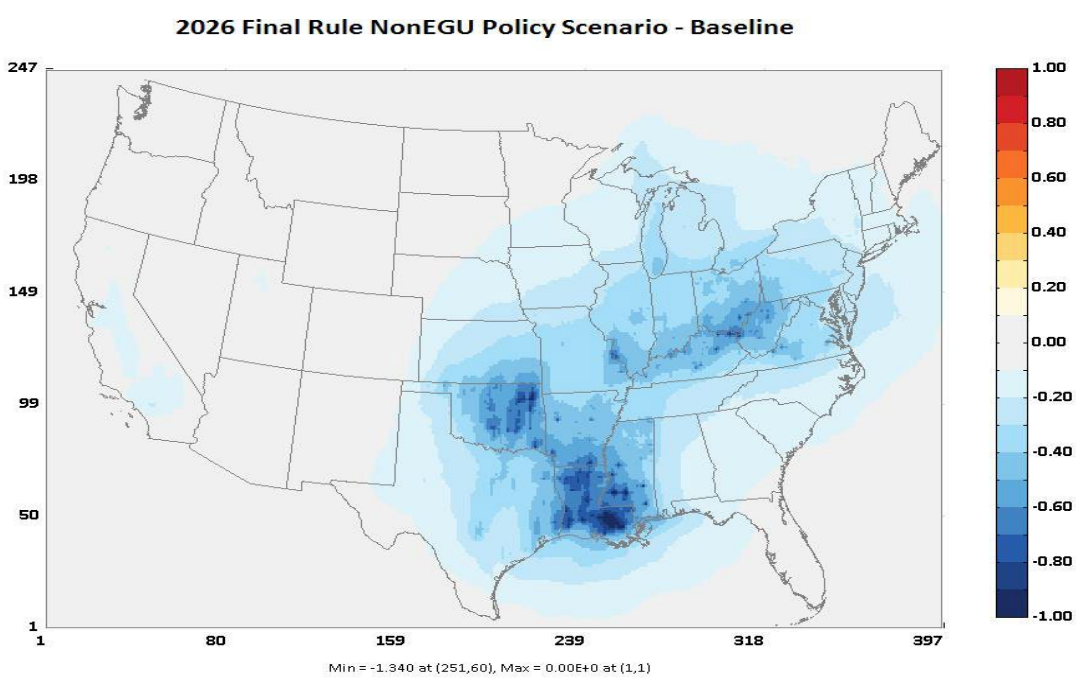


**Figure 3-11. Reduction in AS-MO3 (ppb): 2026 Final Rule non-EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

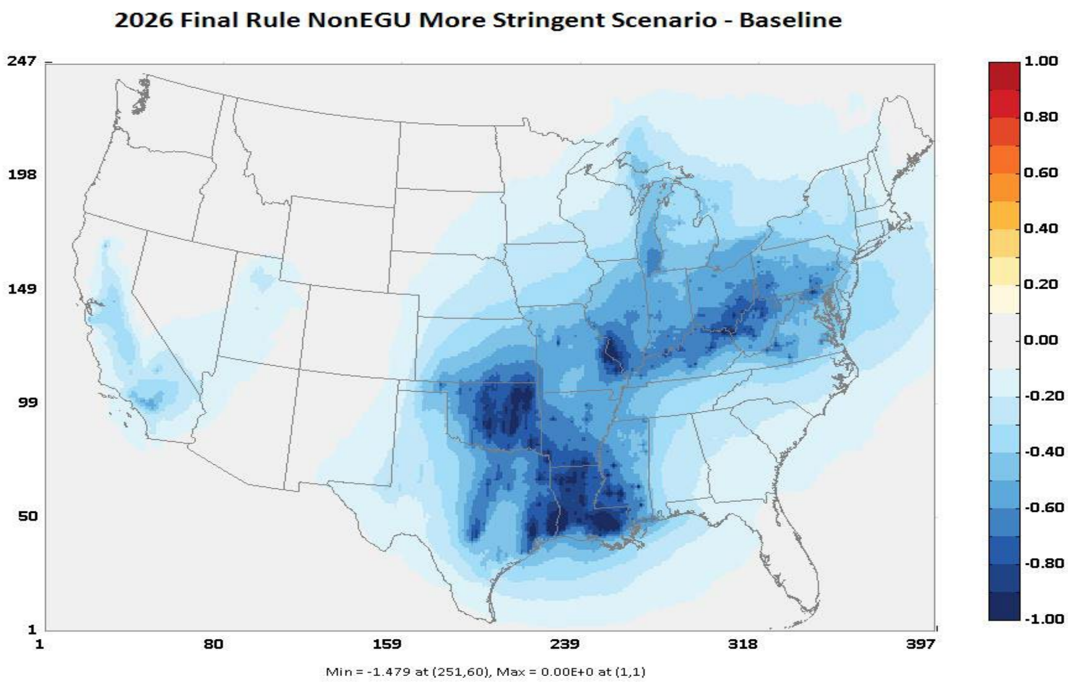


**Figure 3-12. Reduction in AS-MO3 (ppb): 2026 More Stringent non-EGU-only Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

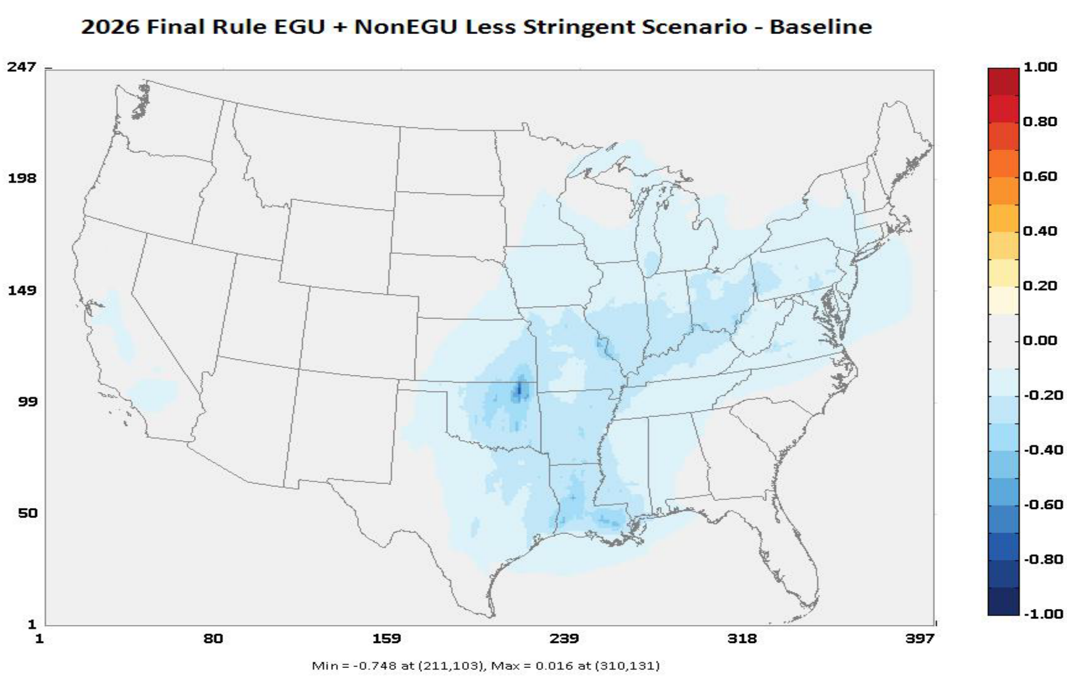


**Figure 3-13. Reduction in AS-MO3 (ppb): 2026 Less Stringent EGU+non-EGU Alterative vs the 2026 Baseline (scale: ± 1.0 ppb)**

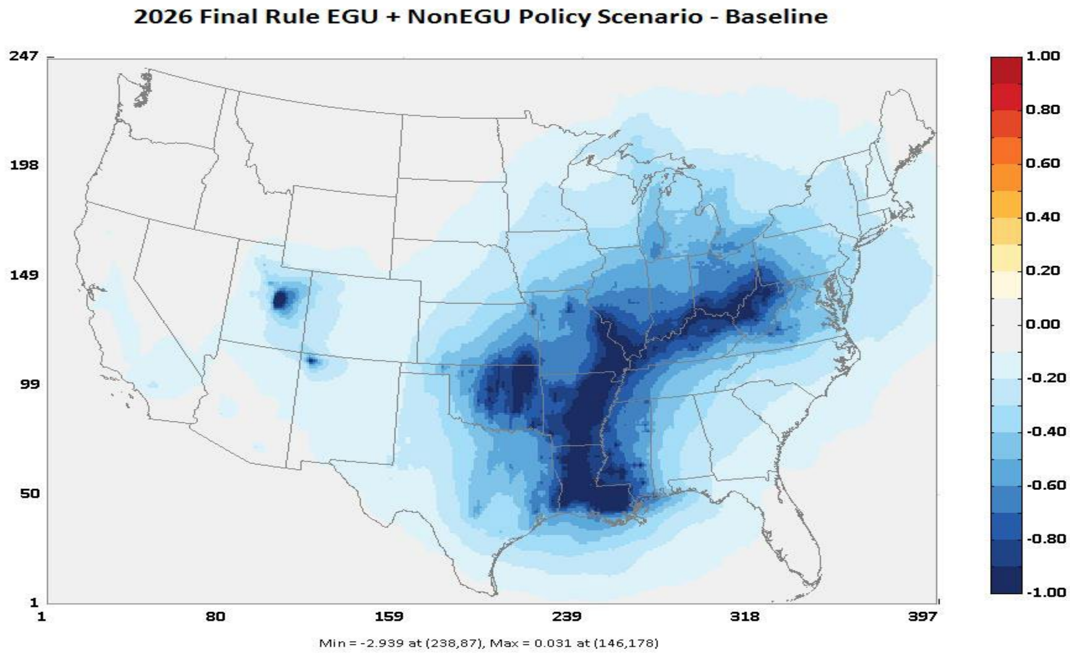


**Figure 3-14. Reduction in AS-MO3 (ppb): 2026 Final Rule EGU+non-EGU Alternative vs the 2026 Baseline (scale: ± 1.0 ppb)**

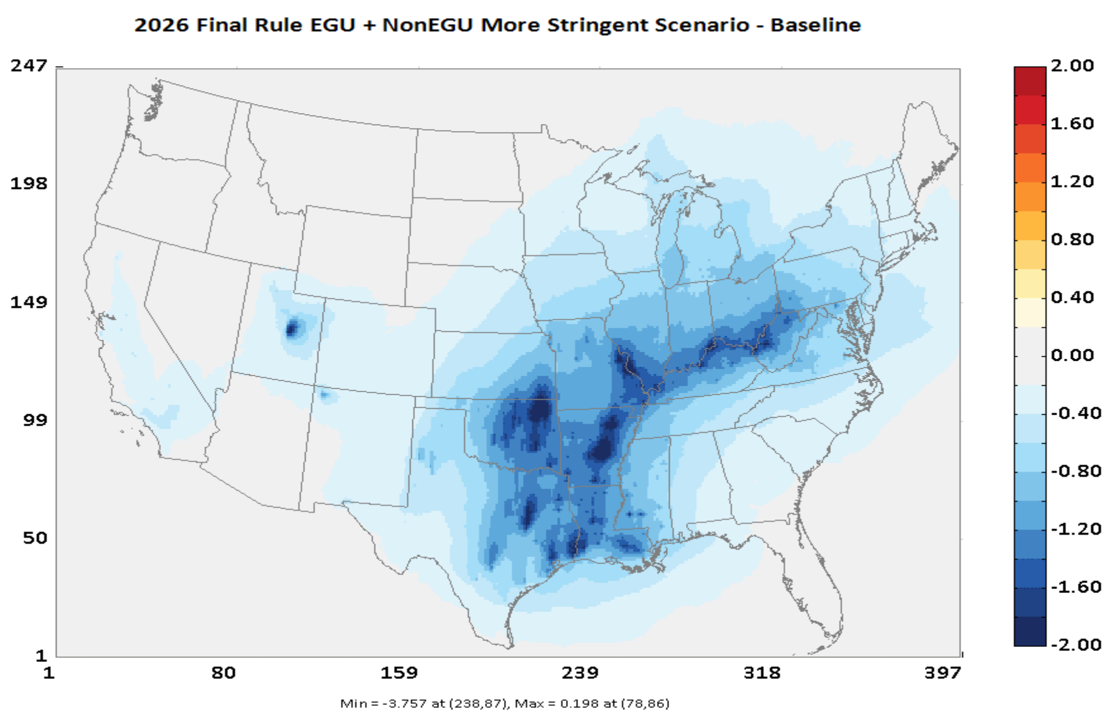


**Figure 3-15. Reduction in AS-MO3 (ppb): 2026 More Stringent EGU+non-EGU Alternative vs the 2026 Baseline (scale: ± 2.0 ppb)**

### *3.2.2 Spatial Distribution of $PM_{2.5}$ Impacts*

In contrast to ozone, $PM_{2.5}$ is comprised of both primary and secondary components. Secondary $PM_{2.5}$ species sulfate and nitrate often exhibit relatively smooth regional patterns without large local gradients while primary $PM_{2.5}$ components often have heterogenous spatial patterns with largest gradients near emissions sources. The spatial field of 2026 baseline annual $PM_{2.5}$ is provided in Figure 3-16. Both secondary and primary $PM_{2.5}$ contribute to the spatial pattern of 2026 baseline annual $PM_{2.5}$ as illustrated by the extensive areas of elevated concentrations over much of the East that are comprised of secondary $PM_{2.5}$ component species. In addition, relatively high concentrations are mainly evident in urban areas and in close proximity to major point sources. These “hot spots” generally reflect the impact of primary PM emissions. Locally high concentrations are also evident in parts of the Northwest as a result of wood stove emissions during the cooler months of the year (Hadley, 2021). High $PM_{2.5}$ concentrations are also evident in California’s Central Valley mainly comprised of particulate nitrate and sulfate (Hasheminassab, 2014).

The impacts of the regulatory control alternatives for EGUs in 2026 on annual EGU $NO_X$, $SO_2$, and $PM_{2.5}$ emissions by state are provided in Table 3-3. Note that negative values in Table 3-3 denote a reduction in emissions and positive values denote an increase in emissions. In Figures 3-17 through 3-19 we present the changes in annual average $PM_{2.5}$ concentrations between the 2026 baseline and the three EGU regulatory control alternatives. The spatial patterns of changes in annual average $PM_{2.5}$ are a result of (1) of the spatial distribution of EGU sources that are predicted to have changes in emissions in the control alternatives compared to the baseline and (2) of the physical or chemical processing that the model simulates in the atmosphere. The emissions data in Table 3-3 show that the reductions in $SO_2$ emissions expected to result from the final rule and more stringent alternative are much larger than emissions reductions of $NO_X$ or $PM_{2.5}$. Geographically, the $SO_2$ emissions reductions are most notable in Arkansas and Louisiana. In addition, there are relatively large reductions in $SO_2$ emissions in Kentucky, Michigan, and Texas. The spatial pattern of reductions in annual average $PM_{2.5}$ concentrations, as shown in Figures 3-17 through 3-19, are consistent with the location of $SO_2$ emissions reductions. The largest reductions in $PM_{2.5}$ are found in and downwind of the states with the largest reductions in emissions.

**Table 3-3. Impact on EGU Annual $NO_X$, $SO_2$, and $PM_{2.5}$ Emissions of each Regulatory Control Alternative for EGUs in 2026 (1,000 tons)[a]**

| State | Final Rule – Baseline | | | | Less Stringent – Baseline | | | | More Stringent – Baseline | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NOx | SO2 | $PM_{2.5}$ | | NOx | SO2 | $PM_{2.5}$ | | NOx | SO2 | $PM_{2.5}$ |
| Alabama | -0.2 | -0.2 | 0.0 | | -0.1 | -0.1 | 0.0 | | -1.1 | -1.3 | -0.1 |
| Arizona | -0.5 | -0.8 | 0.0 | | 0.1 | 0.1 | 0.0 | | 0.8 | 1.4 | 0.0 |
| Arkansas | -0.6 | -15.8 | -0.3 | | -0.6 | -0.1 | 0.0 | | -6.8 | -19.7 | -0.2 |
| California | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.3 | 0.0 | -0.1 |
| Colorado | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | -0.1 | 0.0 |
| Connecticut | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Delaware | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| District of Columbia | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Florida | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Georgia | 0.0 | 0.1 | 0.0 | | -0.1 | 0.0 | 0.0 | | 1.4 | 1.4 | 0.1 |
| Idaho | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Illinois | 0.1 | 0.1 | 0.1 | | 0.0 | 0.0 | 0.0 | | 1.1 | 2.4 | 0.1 |
| Indiana | -0.8 | -1.9 | -0.1 | | -1.1 | -2.8 | -0.2 | | 1.0 | 1.3 | 0.2 |
| Iowa | -0.1 | 0.1 | 0.0 | | -0.1 | -0.1 | 0.0 | | 0.1 | 0.0 | 0.0 |
| Kansas | -0.1 | 0.1 | 0.0 | | 0.0 | 0.0 | 0.0 | | 1.6 | 0.6 | 0.3 |
| Kentucky | 0.0 | 5.7 | 0.0 | | -0.3 | 8.5 | 0.0 | | -11.5 | -22.7 | -0.3 |
| Louisiana | -2.7 | -15.3 | -0.4 | | -2.6 | -9.5 | -0.3 | | -3.0 | -15.7 | -0.4 |
| Maine | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Maryland | 0.0 | -0.1 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Massachusetts | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Michigan | 0.0 | -3.0 | -0.2 | | 0.1 | 0.0 | 0.0 | | -8.1 | -19.4 | -0.8 |
| Minnesota | -1.9 | -0.3 | 0.0 | | -1.9 | -0.2 | 0.0 | | -1.7 | -0.2 | 0.0 |
| Mississippi | -0.1 | -0.1 | 0.0 | | 0.0 | -0.1 | 0.0 | | 0.2 | 0.3 | 0.1 |
| Missouri | 0.1 | -2.6 | -0.2 | | 0.1 | 0.0 | 0.0 | | -7.2 | -1.7 | -0.4 |
| Montana | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Nebraska | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Nevada | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.1 | 0.0 | 0.0 |
| New Hampshire | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| New Jersey | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.1 | 0.0 | 0.0 |
| New Mexico | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| New York | 0.0 | 0.0 | 0.0 | | -0.1 | 0.0 | 0.0 | | 0.1 | 0.0 | 0.0 |
| North Carolina | 0.0 | 0.3 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.3 | -1.4 | 0.0 |
| North Dakota | 0.6 | 0.9 | 0.0 | | 0.4 | 0.6 | 0.0 | | 1.0 | 1.3 | 0.1 |
| Ohio | -2.1 | -2.5 | -0.3 | | -2.1 | -2.2 | -0.2 | | -2.1 | -2.3 | -0.2 |
| Oklahoma | -2.1 | 2.0 | 0.0 | | -2.3 | 3.4 | 0.0 | | -4.8 | 2.3 | 0.0 |
| Oregon | -0.1 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |

| State | Final Rule – Baseline | | | | Less Stringent – Baseline | | | | More Stringent – Baseline | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NOx | SO2 | $PM_{2.5}$ | | NOx | SO2 | $PM_{2.5}$ | | NOx | SO2 | $PM_{2.5}$ |
| Pennsylvania | 0.4 | 0.2 | 0.2 | | -0.1 | -0.2 | 0.0 | | 1.5 | 1.5 | 0.5 |
| Rhode Island | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| South Carolina | 0.0 | -0.1 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | -0.2 | 0.0 |
| South Dakota | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Tennessee | -0.1 | 0.0 | 0.0 | | -0.1 | -0.1 | 0.0 | | 2.2 | 2.9 | 0.6 |
| Texas | 0.1 | -1.2 | 0.0 | | -0.1 | -2.0 | 0.0 | | -17.3 | -45.2 | -0.6 |
| Utah | 0.0 | -3.0 | -0.1 | | 0.0 | -0.7 | 0.0 | | -12.9 | 0.8 | 0.0 |
| Vermont | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 |
| Virginia | 0.0 | 0.0 | 0.1 | | 0.0 | 0.0 | 0.1 | | 0.1 | 0.0 | -0.1 |
| Washington | 0.0 | 0.0 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.2 | 0.0 | 0.0 |
| West Virginia | 3.0 | -1.8 | -0.2 | | 3.0 | 0.0 | 0.0 | | -7.4 | -5.9 | -0.8 |
| Wisconsin | 0.0 | 0.1 | 0.0 | | 0.0 | 0.0 | 0.0 | | 0.1 | 0.0 | 0.0 |
| Wyoming | 0.9 | 1.6 | 0.0 | | -1.1 | -1.3 | 0.0 | | 1.6 | 2.6 | 0.0 |
| Tribal Data | 0.0 | -0.4 | -0.2 | | 0.0 | 0.0 | 0.0 | | -3.0 | -0.9 | -0.5 |
| Nationwide | -6.2 | -37.7 | -1.5 | | -8.9 | -6.8 | -0.7 | | -73.0 | -118.1 | -2.3 |

[a] The imposition of the final rule results in changes in regional electricity flows, resulting in changes in net imports. As a result, some states (even those not subject to the rule) may see changes in emissions as a result of generation shifting.

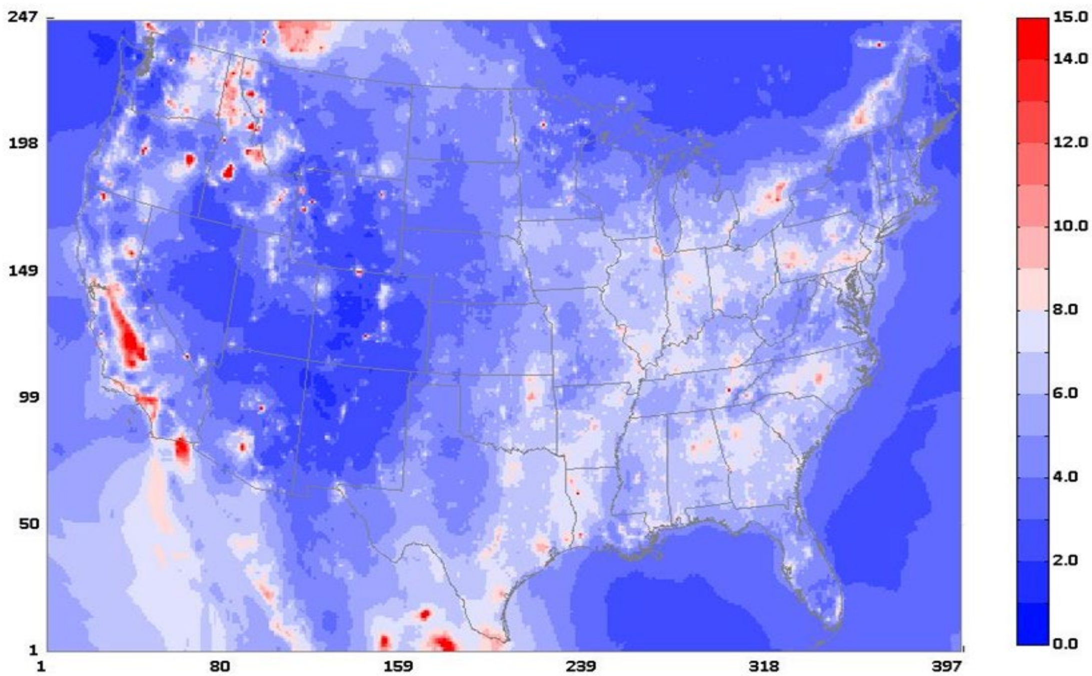


**Figure 3-16. 2026 Baseline Annual Average $PM_{2.5}$ Concentrations (µg/m³)**

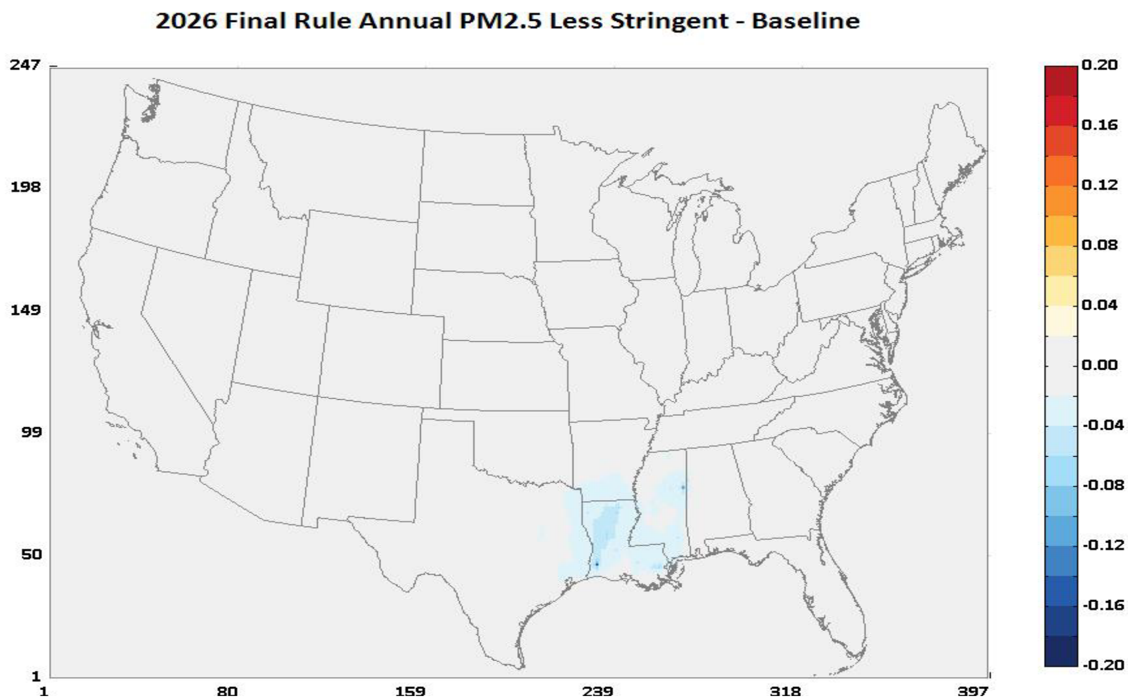


**Figure 3-17. Reduction in annual average $PM_{2.5}$ ($\mu g/m^3$): 2026 Less Stringent EGU-only Alternative vs the 2026 Baseline (scale: $\pm$ 0.2 $\mu g/m^3$)**

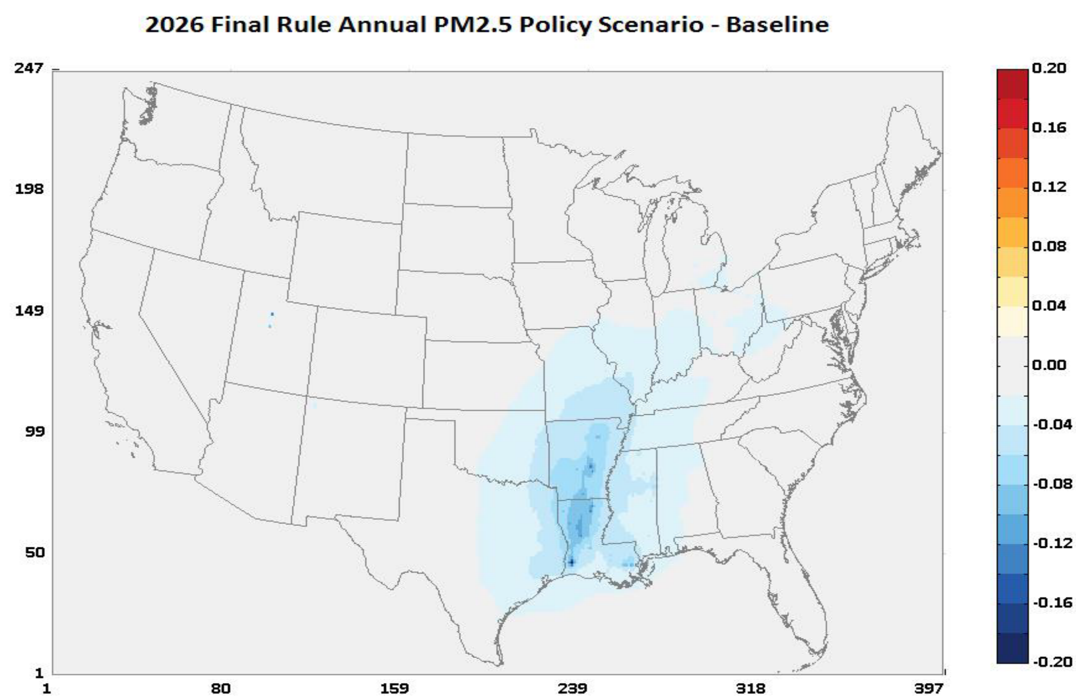


**Figure 3-18. Reduction in Annual Average $PM_{2.5}$ ($\mu g/m^3$): 2026 Final Rule EGU-only Alternative vs the 2026 Baseline (scale: $\pm$ 0.2 $\mu g/m^3$)**

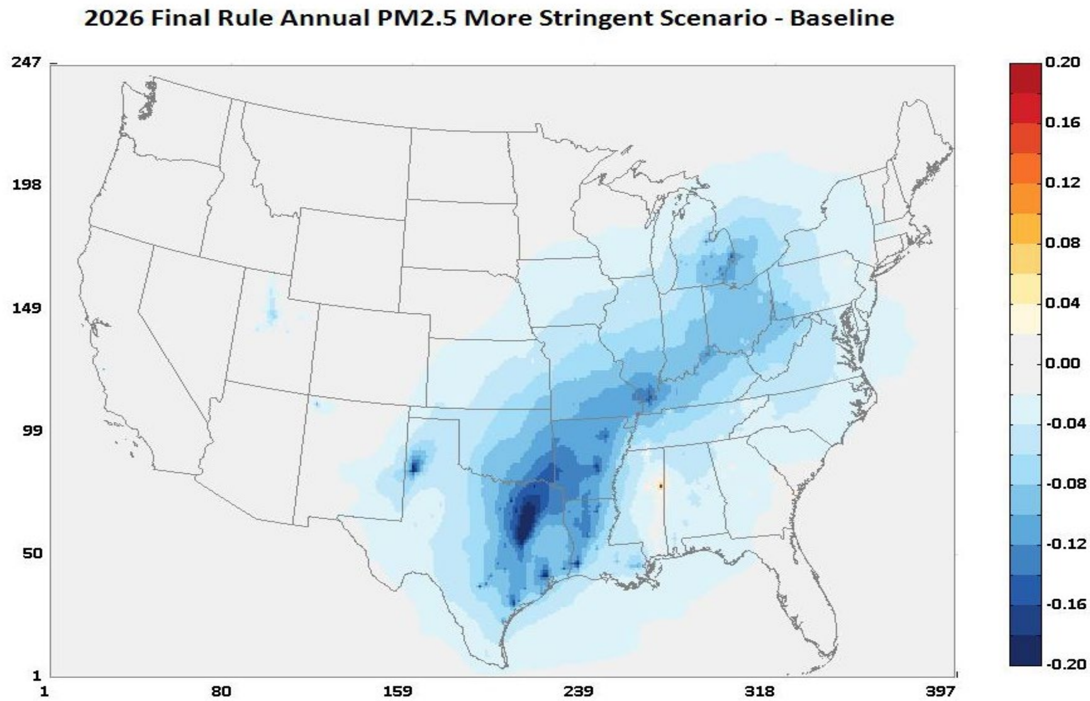


**Figure 3-19. Reduction in Annual Average $PM_{2.5}$ (µg/m$^3$): 2026 More Stringent EGU-only Alternative vs the 2026 Baseline (scale: $\pm$ 0.2 µg/m$^3$)**

## 3.3 Uncertainties and Limitations

One limitation of the scaling methodology for creating ozone and $PM_{2.5}$ surfaces associated with the baseline and regulatory control alternatives described above is that it treats air quality changes from the tagged sources as linear and additive. It therefore does not account for nonlinear atmospheric chemistry and does not account for interactions between emissions of different pollutants and between emissions from different tagged sources. This is consistent with how air quality estimations have been treated in past regulatory analyses (U.S. EPA 2012; 2019; 2020b). We note that air quality is calculated in the same manner for the baseline and the regulatory control alternatives, so any uncertainty associated with these assumptions is carried through both sets of scenarios in the same manner and is thus not expected to impact the air quality differences between scenarios. In addition, emissions changes between baseline and the regulatory control alternatives are relatively small compared to modeled 2026 emissions that form the basis of the source apportionment approach described in Section 3.1. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Dunker et al., 2002; Cohan et al., 2005; Napelenok et al., 2006; Koo et al., 2007; Zavala et al., 2009; Cohan and Napelenok, 2011) and that linear scaling from source apportionment can do a reasonable job of representing impacts of 100 percent of emissions from individual sources (Baker and Kelly 2014). Therefore, while simplistic, it is reasonable to expect that the emissions concentration differences between the baseline and regulatory control alternatives can be adequately represented using this methodology and any uncertainty should be weighed against the speed in which this method may be used to account for spatial differences in the effect of EGU emissions on ozone concentrations.

A second limitation is that the source apportionment contributions represent the spatial and temporal distribution of the emissions from each source tag as they occur in the 2026 modeled case. Thus, the contribution modeling results do not allow us to represent any changes to “within tag” spatial distributions. As a result, the method does not account for any changes of spatial patterns that would result from changes in the relative magnitude of sources within a source tag in the scenarios investigated here.

In addition, the 2023 and 2026 CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the base-year 2016 model outputs have been evaluated against ambient measurements and have been shown to adequately reproduce spatially and temporally varying ozone concentrations (U.S. EPA, 2022a; U.S. EPA, 2022b).

The regulatory control alternatives lead to decreased concentrations of ozone, the extent to which varies by location, relative to the baseline. However, the analysis does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory control alternatives, which introduces uncertainty in the benefits and costs of the alternatives. To the extent the Transport FIP for the 2015 ozone NAAQS will decrease $NO_X$ and consequentially ozone concentrations, these changes may affect compliance with existing NAAQS standards and subsequently affect the actual benefits and costs of the rule. In areas not projected to attain the 2015 ozone NAAQS without further emissions reductions from the baseline, states may be able to avoid applying some emissions control measures to reduce emissions from local sources as a result of this rule. If compliance behavior with the 2015 ozone NAAQS were accounted for in the baseline in this RIA there may be additional social benefits from reduced compliance costs, while the level and spatial pattern of changes in ozone concentrations, and their associated health and ecological benefits, would differ. The directional effect on the benefits, costs, and net-benefits of this source of uncertainty is ambiguous.

Similarly, the regulatory control alternatives may project decreases in ozone concentrations in areas attaining the NAAQS in the baseline. In practice, these potential changes in concentrations may influence NAAQS compliance plans in these areas, which in turn would further influence concentrations and the cost of complying with the NAAQS. However, such behavior will be mitigated by NAAQS requirements such as Prevention of Significant Deterioration (PSD) requirements. This RIA does not account for how interaction with NAAQS compliance would affect the benefits and costs of the regulatory control alternatives.

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# APPENDIX 3A: IMPACTS ON OZONE DESIGN VALUES OF THE FINAL RULE IN 2026

In this appendix we provide the estimated impacts on projected 2026 ozone design values that are expected to result from the combined EGU and non-EGU final rule analyzed in this RIA. As described in Chapter 1, the regulatory control alternatives include the final rule along with alternatives that reflect less stringent and more stringent controls on EGUs and non-EGUs. Because of timing constraints, we were only able to perform full-scale photochemical air quality modeling to quantify the ozone impacts for the 2026 final rule.

## 3A.1 Projected Impacts on Ozone Design Values

The "ppb" impacts in 2026 from the final rule control case are provided in Table 3A-1 for those monitoring sites that are identified as nonattainment or maintenance-only receptors in 2026 and/or in 2023, based on air quality modeling and monitored data. Table 3A-2 provides the same information for the additional violating monitor-based maintenance-only receptors in 2023.[62]

For the final rule control case, the largest reductions in ozone design values at the receptors in Tables 3A-1 and 3A-2 are predicted to occur in the Houston-Galveston-Brazoria, Texas area. In this area the reductions from the final rule case range from 0.7 to 0.9 ppb. At most of the receptors in both the Dallas/Ft Worth and the New York/Coastal Connecticut areas the reductions in ozone range from 0.4 to 0.5 ppb. At receptors in Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan, ozone is projected to decline by 0.3 to 0.4 ppb, but by as much as 0.5 ppb at the receptor in Muskegon, MI. Lesser reductions of 0.1 ppb are predicted in the urban and near-urban receptors in Chicago. In the West, ozone reductions just under 0.2 ppb are predicted at receptors in Denver with slightly greater reductions, just above 0.2 ppb, at receptors in Salt Lake City. At receptors in Phoenix, California, El Paso/Las Cruces, and southeast New Mexico the reductions in ozone are predicted to be less than 0.1 ppb. The geographical variations of the impacts on design values are generally consistent with the spatial fields in Figure 3-14, which shows the impact on AS-MO3 of the final rule case EGU+non-EGU $NO_X$ reductions in 2026. Table 3A-3 provides the impacts on EGU+non-EGU ozone season $NO_X$

[62] The approaches for identifying modeling-based and violating monitor-based receptors are described in the preamble for this final rule.

emissions that result from the emissions controls modeled in the final rule case. Note that negative values in Table 3A-3 denote a reduction in emissions whereas positive values denote an increase in emissions. The impacts on emissions are rank ordered by the amount of emissions reduction (i.e., negative values are at the top). That is, in Table 3A-3 the states with the largest $NO_X$ emissions reductions in the final rule case are at the top of the list. Examining the emissions data in Table 3A-3 together with the ppb impacts in Table 3A-1 and 3A-2 indicate that the largest reductions in receptor design values are projected to occur near and downwind of the states with the largest reductions in ozone season EGU+non-EGU $NO_X$ emissions.

**Table 3A-1. Ozone Impacts at Projected Nonattainment and Maintenance-Only Receptors (ppb) for the Final Rule Modeled Control Case in 2026**

| Site ID | State | County | Final Rule Case |
|---|---|---|---|
| 40278011 | Arizona | Yuma | -0.06 |
| 60650016 | California | Riverside | -0.06 |
| 60651016 | California | Riverside | -0.08 |
| 80350004 | Colorado | Douglas | -0.17 |
| 80590006 | Colorado | Jefferson | -0.14 |
| 80590011 | Colorado | Jefferson | -0.11 |
| 80690011 | Colorado | Larimer | -0.24 |
| 90010017 | Connecticut | Fairfield | -0.38 |
| 90013007 | Connecticut | Fairfield | -0.45 |
| 90019003 | Connecticut | Fairfield | -0.46 |
| 90099002 | Connecticut | New Haven | -0.43 |
| 170310001 | Illinois | Cook | -0.08 |
| 170314201 | Illinois | Cook | -0.09 |
| 170317002 | Illinois | Cook | -0.11 |
| 350130021 | New Mexico | Dona Ana | -0.02 |
| 350130022 | New Mexico | Dona Ana | -0.03 |
| 350151005 | New Mexico | Eddy | -0.02 |
| 350250008 | New Mexico | Lea | -0.02 |
| 480391004 | Texas | Brazoria | -0.82 |
| 481210034 | Texas | Denton | -0.42 |
| 481410037 | Texas | El Paso | -0.03 |
| 481671034 | Texas | Galveston | -0.92 |
| 482010024 | Texas | Harris | -0.68 |
| 482010055 | Texas | Harris | -0.75 |
| 482011034 | Texas | Harris | -0.72 |
| 482011035 | Texas | Harris | -0.70 |

| Site ID | State | County | Final Rule Case |
|---|---|---|---|
| 490110004 | Utah | Davis | -0.22 |
| 490353006 | Utah | Salt Lake | -0.22 |
| 490353013 | Utah | Salt Lake | -0.15 |
| 550590019 | Wisconsin | Kenosha | -0.21 |
| 551010020 | Wisconsin | Racine | -0.22 |
| 551170006 | Wisconsin | Sheboygan | -0.30 |

**Table 3A-2. Ozone Impacts at Violating-Monitor Maintenance-Only Receptors (ppb) for the Final Rule Modeled Control Case in 2026**

| Site ID | State | County | Final Rule Case |
|---|---|---|---|
| 40070010 | Arizona | Gila | -0.07 |
| 40130019 | Arizona | Maricopa | -0.04 |
| 40131003 | Arizona | Maricopa | -0.05 |
| 40131004 | Arizona | Maricopa | -0.05 |
| 40131010 | Arizona | Maricopa | -0.05 |
| 40132001 | Arizona | Maricopa | -0.04 |
| 40132005 | Arizona | Maricopa | -0.06 |
| 40133002 | Arizona | Maricopa | -0.04 |
| 40134004 | Arizona | Maricopa | -0.05 |
| 40134005 | Arizona | Maricopa | -0.04 |
| 40134008 | Arizona | Maricopa | -0.05 |
| 40134010 | Arizona | Maricopa | -0.06 |
| 40137020 | Arizona | Maricopa | -0.04 |
| 40137021 | Arizona | Maricopa | -0.06 |
| 40137022 | Arizona | Maricopa | -0.05 |
| 40137024 | Arizona | Maricopa | -0.04 |
| 40139702 | Arizona | Maricopa | -0.05 |
| 40139704 | Arizona | Maricopa | -0.06 |
| 40139997 | Arizona | Maricopa | -0.04 |
| 40218001 | Arizona | Pinal | -0.03 |
| 80013001 | Colorado | Adams | -0.13 |
| 80050002 | Colorado | Arapahoe | -0.18 |
| 80310002 | Colorado | Denver | -0.13 |
| 80310026 | Colorado | Denver | -0.13 |
| 90079007 | Connecticut | Middlesex | -0.49 |
| 90110124 | Connecticut | New London | -0.41 |
| 170310032 | Illinois | Cook | -0.10 |
| 170311601 | Illinois | Cook | -0.10 |

| Site ID | State | County | Final Rule Case |
|---|---|---|---|
| 181270024 | Indiana | Porter | -0.23 |
| 260050003 | Michigan | Allegan | -0.39 |
| 261210039 | Michigan | Muskegon | -0.50 |
| 320030043 | Nevada | Clark | -0.15 |
| 350011012 | New Mexico | Bernalillo | -0.04 |
| 350130008 | New Mexico | Dona Ana | -0.02 |
| 361030002 | New York | Suffolk | -0.39 |
| 390850003 | Ohio | Lake | -0.70 |
| 480290052 | Texas | Bexar | -0.28 |
| 480850005 | Texas | Collin | -0.48 |
| 481130075 | Texas | Dallas | -0.45 |
| 481211032 | Texas | Denton | -0.41 |
| 482010051 | Texas | Harris | -0.69 |
| 482010416 | Texas | Harris | -0.73 |
| 484390075 | Texas | Tarrant | -0.30 |
| 484391002 | Texas | Tarrant | -0.38 |
| 484392003 | Texas | Tarrant | -0.38 |
| 484393009 | Texas | Tarrant | -0.32 |
| 490571003 | Utah | Weber | -0.27 |
| 550590025 | Wisconsin | Kenosha | -0.22 |
| 550890008 | Wisconsin | Ozaukee | -0.24 |

**Table 3A-3. Impact on EGU and Non-EGU Ozone Season $NO_X$ Emissions by State in the 2026 Modeled Control Case (1,000 tons)**

| State | Final - Baseline |
|---|---|
| Louisiana | -12.6 |
| Oklahoma | -9.9 |
| Texas | -7.7 |
| Arkansas | -7.3 |
| Missouri | -6.9 |
| Michigan | -5.3 |
| Kentucky | -5.3 |
| Utah | -5.2 |
| Ohio | -4.9 |
| West Virginia | -3.7 |
| Indiana | -3.1 |
| Mississippi | -3.0 |
| Pennsylvania | -2.1 |

| State | Final - Baseline |
|---|---|
| Illinois | -2.1 |
| California | -1.7 |
| Virginia | -1.6 |
| Tribal | -1.3 |
| Minnesota | -1.2 |
| New York | -1.2 |
| New Jersey | -0.3 |
| Arizona | -0.3 |
| Alabama | -0.2 |
| Maryland | -0.1 |
| Nevada | 0.0 |
| Rhode Island | 0.0 |
| Florida | 0.0 |
| Maine | 0.0 |
| Oregon | 0.0 |
| Vermont | 0.0 |
| District of Columbia | 0.0 |
| Washington | 0.0 |
| Montana | 0.0 |
| Delaware | 0.0 |
| Massachusetts | 0.0 |
| New Hampshire | 0.0 |
| New Mexico | 0.0 |
| Connecticut | 0.0 |
| Tennessee | 0.0 |
| South Dakota | 0.0 |
| Georgia | 0.0 |
| Nebraska | 0.1 |
| Idaho | 0.1 |
| Colorado | 0.1 |
| North Dakota | 0.1 |
| Wisconsin | 0.1 |
| South Carolina | 0.2 |
| Iowa | 0.3 |
| North Carolina | 0.4 |
| Kansas | 0.4 |
| Wyoming | 0.5 |

## CHAPTER 4: COST, EMISSIONS, AND ENERGY IMPACTS

### Overview

This chapter reports the compliance costs, emissions, and energy analyses performed for the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS). The EPA used the Integrated Planning Model (IPM)[63] to conduct the electric generating units (EGU) analysis discussed in this chapter and information from the Control Measures Database (CMDB)[64] and the 2019 emissions inventory to conduct analysis for non-electric generating units (non-EGUs) for 2026. As explained in detail below, this chapter presents analysis for three regulatory control alternatives that differ in the level of EGU nitrogen oxides ($NO_X$) ozone season emissions budgets in the 22 states subject to this action beginning in 2023. These regulatory control alternatives impose different budget levels for EGUs. The different budget levels are calculated assuming the application of different $NO_X$ mitigation technologies. The analysis for EGUs in the chapter does not include effects from certain provisions of the Inflation Reduction Act (IRA) of 2022 in the baseline. The effects of accounting for the IRA on the power sector costs, emission reductions and other impacts of this final rule are provided in a sensitivity analysis presented in Appendix 4A. The chapter also presents three regulatory control alternatives for non-EGUs that differ in the control technologies assumed to be adopted for compliance.

The chapter is organized as follows: following a summary of the regulatory control alternatives analyzed and a summary of the EPA's methodologies, we present estimates of compliance costs for EGUs, as well as estimated impacts on emissions, generation, capacity, fuel use, fuel price, and retail electricity price for a few years. We then present a summary of the results of the non-EGU assessment for 2026. Section 4.6 of this chapter describes the relationship between the compliance cost estimates and social costs.

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[63] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.
[64] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

## 4.1 Regulatory Control Alternatives

This rule establishes $NO_X$ emissions budgets requiring fossil fuel-fired electric generating units (EGUs) in 22 states to participate in an allowance-based ozone season (May 1 through September 30) trading program beginning in 2023. The EGUs covered by the FIPs and subject to the budget are fossil-fired EGUs with >25-megawatt (MW) capacity. For details on the derivation of these budgets, please see Section V.C. of the preamble.

The FIP requirements establish ozone season $NO_X$ emissions budgets for EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) $NO_X$ Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[65] The EPA is amending existing FIPs for 12 states currently participating in the CSAPR $NO_X$ Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update (with respect to the 2008 ozone NAAQS) with new emissions budgets. For seven states currently covered by the CSAPR $NO_X$ Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. The EPA is issuing new FIPs for three states not currently covered by any CSAPR $NO_X$ ozone season trading program: Minnesota, Nevada, and Utah.

In this rule, we introduce additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and a backstop daily emission rate for most coal-fired units, along with an adjustment to the total size of the allowance bank, which is 21 percent of the sum of the state emissions budgets for the

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

current control period until 2030 (at which point it declines to 10.5%), that were not included in previous CSAPR $NO_X$ ozone season trading programs. These enhancements will help maintain control stringency over time and improve emissions performance at individual units, offering an extra measure of assurance that existing pollution controls will be operated during the ozone season. This analysis incorporates the daily emission rate requirement for units with existing controls by forcing operation of these controls in the ozone season for affected sources starting in the 2023 run year (although the rule would not impose some of these limits until 2024).

The additional EGU emissions reductions[66] beginning in 2026 are based on the feasibility of control installation for EGUs in 19 states (19-state region) that remain linked to downwind nonattainment and maintenance receptors in 2026.[67] Starting in 2030, consistent with the structure of the final rule, this analysis imposes the backstop emission rate for certain larger coal-fired units that do not already have SCR installed, which forces these units identified as having SCR retrofit potential to either install new SCR retrofits, find other means of compliance, or retire.[68] The analysis does not explicitly capture the dynamic budget adjustments over time in the modeling, but the forced operation of controls during the ozone season over the forecast period (even in the absence of binding mass limits) approximates this feature of the program design.[69] For details of the controls modeled for each of the regulatory control alternatives please see

[66] The model was not explicitly constrained to limit the bank to 21% of the sum of state budgets in the first period and 10.5% thereafter. However, the model solve was reviewed to ensure that any allowances withdrawn from the bank did not violate this threshold. If this condition had been violated (which did not occur for these runs), the model would have been re-run with an additional limit incorporated.

[67] For EGUs, the 19 states linked in 2026 include Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to the EPA's assumed EGU SCR retrofit mitigation technologies.

[68] The rule assumes SCR retrofit potential starting in 2026, and this is reflected in the 2026/27 state emission budgets. The daily backstop emission rate does not apply for large coal units that do not already have SCR controls until the second ozone season after they install the control or by 2030 at the latest. The EPA's IPM model run years are 2025, 2028 and 2030. The SCR compliance behavior is generally expected to occur no later than 2030. Therefore, the EPA models this daily backstop emission rate in 2030 (when choosing between model run year 2025 and 2028) while imposing 2026 and 2027 SCR-retrofit-related emission reductions reflected in those control periods' emission budgets in the model run-year 2025 to model compliance cost in the first years by which the technology may be put into place for some units. (In this case, we are treating 2025 as sufficiently reflective of conditions in 2026 to be usable for this RIA analysis.)

[69] In years in which the dynamic budgets are implemented, the budgets would be calculated based on historical heat input data and assuming optimization of existing controls as well as installation of the controls required by the rule. While the modeling does not include lower budgets in response to modeled declines in heat input, forcing existing controls to operate in an environment of fluctuating future heat input approximates the underlying behavior and captures the associated costs.

Table 4-2 below.

This rule also includes $NO_X$ emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. Table 4-1 presents the industries, emissions unit types, form of emissions limit, and $NO_X$ emissions limitations for the final rule. For the less and more stringent alternatives, specific emission limits are not identified, and certain control technologies are assumed for compliance with emissions limits that would be more or less stringent than the final rule.

**Table 4-1. Summary of Non-EGU Industries, Emissions Unit Types, Form of Final Emissions Limits, and Final Emissions Limits**

| Industry | Emissions Unit Type | Form of Final Emissions Limits | Final Emissions Limits |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engines | Grams per horsepower per hours (g/hp-hr) | Four Stroke Rich Burn: 1.0 g/hp-hr<br>Four Stroke Lean Burn: 1.5 g/hp-hr<br>Two Stroke Lean Burn: 3.0 g/hp-hr |
| Cement and Concrete Product Manufacturing | Kilns | Pounds per ton (lbs/ton) of clinker | Long Wet: 4.0 lb/ton<br>Long Dry: 3.0 lb/ton<br>Preheater: 3.8 lb/ton<br>Precalciner: 2.3 lb/ton<br>Preheater/Precalciner: 2.8 lb/ton |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | lbs $NO_X$ per/ton of steel and lbs/mmBtu[a] | Test and set limit based on installation of Low-NOx Burners |
| Glass and Glass Product Manufacturing | Furnaces | lbs/ton glass produced | Container Glass Furnace: 4.0 lb/ton<br>Pressed/Blown Glass Furnace: 4.0 lb/ton<br>Fiberglass Furnace: 4.0 lb/ton<br>Flat Glass Furnace: 9.2 lb/ton |
| Iron and Steel Mills and Ferroalloy Manufacturing<br>Metal Ore Mining<br>Basic Chemical Manufacturing<br>Petroleum and Coal Products Manufacturing<br>Pulp, Paper, and Paperboard Mills | Boilers | lbs/mmBtu[a] | Coal: 0.20 lb/mmBtu<br>Residual Oil: 0.20 lb/mmBtu<br>Distillate Oil: 0.12 lb/mmBtu<br>Natural Gas: 0.08 lb/mmBtu |
| Solid Waste Combustors and Incinerators | Combustors or Incinerators | ppmvd on a 24-hour averaging period and ppmvd on a 30-day averaging period | 110 ppmvd on a 24-hour averaging period<br>105 ppmvd on a 30-day averaging period |

[a] Heat input limit.

This regulatory impact analysis (RIA) evaluates the benefits, costs and certain impacts of compliance with three regulatory control alternatives: the Transport FIP for the 2015 ozone NAAQS, a less-stringent alternative, and a more-stringent alternative. Table 4-2 below presents the less stringent alternatives, final rule requirements, and more stringent alternatives for EGUs and non-EGUs. For the purposes of summarizing the results of the benefits and costs of these alternatives, the less stringent alternative for EGUs is presented with the less stringent alternative for non-EGUs. However, the cost, emissions, and energy impacts for the EGU and non-EGU alternatives are evaluated separately.

**Table 4-2. Regulatory Control Alternatives for EGUs and Non-EGUs**

| Regulatory Control Alternative | $NO_X$ Controls Implemented for EGUs within IPM[a, b] |
|---|---|
| Less Stringent Alternative | 1) 2023 onwards: Fully operate existing selective catalytic reduction (SCRs) during ozone season<br>2) 2023 onwards: Fully operate existing selective non-catalytic reduction (SNCRs) during ozone season<br>3) In 2023 install state-of-the-art combustion controls[c]<br>4) In 2030 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls.[d] |
| Final Rule | (All Controls above and)<br>5) In 2025 model run year, impose Engineering Analysis derived emissions budgets that assume installation of SCR controls on coal units greater than 100 MW within the 19-state region that lack SCR controls. |
| More Stringent Alternative | (Controls 1 – 5 above and)<br>6) In 2025 model run year, impose backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, forcing units to retrofit or retire. |
| **Regulatory Control Alternative** | **$NO_X$ Emissions Limits for Non-EGUs – Emissions Unit Types, Industries, and Controls Assumed for Compliance** |
| Less Stringent Alternative | 1) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – Adjust Air-to-Fuel Ratio<br>2) Kilns in Cement and Cement Product Manufacturing – install SNCR<br>3) Reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing – install Low NOx burners (LNB)<br>4) Furnaces in Glass and Glass Product Manufacturing – install LNB<br>5) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install SNCR<br>6) Combustors or Incinerators in Solid Waste Combustors and Incinerators – install Advanced NSCR (ANSCR) or LN$^{TM}$ and SNCR[e] |
| Final Rule | (Controls 2, 3, 4, and 6 above, plus changes in assumed controls noted below)<br>7) Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas – depending on engine type, install *Layered Combustion, non-selective catalytic reduction (NSCR), or SCR*<br>8) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (coal- or oil-fired) or LNB and FGR (natural gas-fired only)* |
| More Stringent Alternative | (Controls 3, 6, 7 above, plus changes in assumed controls noted below) |

| | |
|---|---|
| | 9) Kilns in Cement and Cement Product Manufacturing – install *SCR*<br>10) Furnaces in Glass and Glass Product Manufacturing – install *SCR*<br>11) Boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills – install *SCR (natural gas-fired only)* |

[a] 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.
[b] NOx mass budgets are imposed in all run years in IPM (2023-2050) consistent with the measures highlighted in this table.
[c] The final rule implementation allows for the reduction associated with state-of-the-art combustion controls to occur by 2024. It is captured in 2023 in this analysis to fully assess the impact of the mitigation measures occuring prior to 2026.
[d] For the 19 states with EGU obligations that are linked in 2026 the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas units greater than 100 MW that have historically emitted at least 150 tons of $NO_X$ per ozone season. The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to the EPA's assumed EGU SCR retrofit mitigation technologies. The 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.
[e] Covanta has developed a proprietary low NOx combustion system (LN™) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

### *4.1.1 EGU Regulatory Control Alternatives Analyzed*

The illustrative emission budgets in this RIA represent EGU $NO_X$ ozone season emission budgets for each state in 2023 and in 2026.[70] This RIA analyzes the Transport FIP for the 2015 ozone NAAQS emission budgets, as well as a more and a less stringent alternative to the Transport FIP for the 2015 ozone NAAQS. The more and less stringent alternatives differ from the final rule in that they set different $NO_x$ ozone season emission budgets for the affected EGUs and different dates for compliance with the backstop emission rate. All three scenarios use emission budgets that were developed using uniform control stringency represented by $900 per ton of $NO_x$ (2016$) in 2023 (i.e., optimizing existing controls and installation of state-of-the-art combustion controls). The final rule and more stringent alternative use emission budgets that were developed using a uniform control stringency represented by $11,000 per ton of $NO_x$ (2016$) in 2025 (i.e., installation of SCR and SNCR post-combustion controls), while the less

[70] Mapping each year in the analysis time period to a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. Run year 2023 is mapped to calendar year 2023, while run year 2025 is mapped to 2024-26, run year 2028 is mapped to 2027-29, run year 2030 is mapped to 2030-31, run year 2035 is mapped to 2032-37, run year 2040 is mapped to 2038-42, while run year 2045 is mapped to 2043-47.

stringent alternative uses emissions budgets that were developed using a uniform control stringency represented by \$11,000 per ton of $NO_x$ (2016\$) in 2030. The final rule and less-stringent alternative defer the backstop emission rate to the 2030 run year, while the more stringent alternative imposes the backstop emission rate in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed by the relevant run year (2025 or 2030 depending on alternative) on all coal units within the 19-state region that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units).

The state emission budgets in this RIA are illustrative for several reasons. First, they reflect an estimate of the future budget based on the EPA's preset budget methodology. However, as described in the preamble, the implemented state budget may be either the preset budget or the dynamic budget starting in 2026. As noted above, other parameters are used to capture the dynamic budget impacts in this modeling, as the future heat input needed to derive that budget number is not yet known. Second, the budgets are illustrative as the utilized 2023 preset budgets reflect full implementation of existing control optimization and upgrade to state-of-the-art combustion control potential. However, the final rule state emission budgets and implementation allows the limited number of reductions related to state-of-the-art combustion control to be realized up through 2024. Finally, the illustrative budgets in this RIA were derived using draft results from the EPA's data and engineering analysis up through October 2022. The preset budgets reflected in the final rule are slightly different in some cases due to new data or comment incorporation that occurred between October of 2022 and January 2023. The Agency conducted additional sensitivity analysis using IPM demonstrating that the substituting in the final preset state emission budgets instead of the illustrative ones modeled made no significant difference in the cost implications described in the body of the RIA. The analysis is provided in the docket for this rulemaking.

The three illustrative regulatory control alternatives presented in this RIA provide a reasonable approximation of the impacts of the rule, as well as an evaluation of the relative impacts of two regulatory alternatives. Table 4-3. reports the illustrative EGU $NO_X$ ozone season emission budgets that are evaluated in this RIA for the 2023 – 2030 IPM run years. As described above, starting in 2023, IPM is constrained to disallow emissions from affected EGUs in the 22 states to exceed the sum of emissions budgets but for the ability to use banked allowances from previous years for compliance. For individual states, IPM is constrained to disallow emissions from exceeding 121% of the state emission budget (the assurance levels). In the IPM modeling of these RIA alternatives, no further reductions in budgets occur after 2030, and budgets remain in place for future years.[71] These budgets are imposed in addition to the control measures outlined in Table 4-2.

**Table 4-3. Illustrative $NO_X$ Ozone Season Emission Budgets (Tons) Evaluated by IPM Run Year**

| Region | Final Rule and More Stringent Alternative | | | | Less Stringent Alternative | | | |
|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2028 | 2030 | 2023 | 2025 | 2028 | 2030 |
| Alabama | 6,595 | 6,236 | 6,236 | 4,610 | 6,595 | 6,236 | 6,236 | 4,610 |
| Arkansas | 8,927 | 4,031 | 4,031 | 3,582 | 8,927 | 8,700 | 8,700 | 3,582 |
| Illinois | 7,474 | 5,363 | 4,555 | 4,050 | 7,474 | 6,415 | 4,985 | 4,050 |
| Indiana | 12,440 | 8,633 | 8,633 | 6,307 | 12,440 | 9,658 | 9,658 | 6,307 |
| Kentucky | 13,204 | 7,862 | 7,862 | 7,679 | 13,204 | 12,515 | 12,515 | 7,679 |
| Louisiana | 9,311 | 3,864 | 2,969 | 2,969 | 9,311 | 9,089 | 6,684 | 2,969 |
| Maryland | 1,206 | 592 | 592 | 592 | 1,206 | 592 | 592 | 592 |
| Michigan | 10,275 | 5,997 | 5,997 | 5,691 | 10,275 | 8,626 | 8,626 | 5,691 |
| Minnesota | 5,504 | 2,905 | 2,905 | 1,663 | 5,504 | 2,905 | 2,905 | 1,663 |
| Mississippi | 5,024 | 1,859 | 1,527 | 1,527 | 5,024 | 4,763 | 2,817 | 1,527 |
| Missouri | 12,598 | 7,329 | 7,329 | 6,770 | 12,598 | 11,063 | 11,063 | 6,770 |
| Nevada | 2,391 | 1,051 | 1,051 | 818 | 2,391 | 1,051 | 1,051 | 818 |
| New Jersey | 768 | 768 | 768 | 768 | 768 | 768 | 768 | 768 |
| New York | 3,858 | 3,333 | 3,333 | 3,333 | 3,858 | 3,858 | 3,858 | 3,333 |
| Ohio | 9,134 | 7,953 | 6,934 | 6,399 | 9,134 | 7,953 | 6,934 | 6,399 |
| Oklahoma | 10,271 | 3,842 | 3,842 | 3,842 | 10,271 | 9,044 | 9,044 | 3,842 |
| Pennsylvania | 8,918 | 7,146 | 7,146 | 4,816 | 8,918 | 8,691 | 8,691 | 4,816 |
| Texas | 40,294 | 22,964 | 22,407 | 21,631 | 40,294 | 36,173 | 34,678 | 21,631 |
| Utah | 15,755 | 2,604 | 2,604 | 2,604 | 15,755 | 9,934 | 9,934 | 2,604 |
| Virginia | 3,065 | 2,373 | 2,373 | 1,951 | 3,065 | 2,756 | 2,756 | 1,951 |
| West Virginia | 13,306 | 9,678 | 9,678 | 9,678 | 13,306 | 11,958 | 11,958 | 9,678 |
| Wisconsin | 6,295 | 3,407 | 3,407 | 3,407 | 6,295 | 3,407 | 3,407 | 3,407 |
| **Aggregated State Emission Budgets** | **206,616** | **119,789** | **116,178** | **104,685** | **206,616** | **176,153** | **167,860** | **104,685** |

[71] In 2030 onwards, dynamic budgets may cause the budgets to decrease. While the EPA does not model this feature, the assumption of continued optimization of existing controls approximates compliance behavior and associated costs that would result from dynamic budgets.

Note that EGUs have flexibility in determining how they will comply with the allowance trading program. As discussed below, the way that they comply may differ from the methods forecast in the modeling for this RIA. See Section 4.3 for further discussion of the modeling approach used in the analysis presented below.

*4.1.2 Non-EGU Regulatory Control Alternatives Analyzed*

As discussed in Section I.B. of the preamble and Sections 4.4 and 4.5 below, we used the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost per ton values from the control measures database (CMDB), to estimate $NO_X$ emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of $SO_2$, $PM_{2.5}$, $CO_2$ and other pollutants that may be associated with controls on non-EGU emissions units. For details about the non-EGU assessment and the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs* available in the docket.[72]

The rule imposes emissions limits on each of the emission unit types identified in Table 4-1. The less stringent alternative assumes less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills relative to the final rule. The more stringent alternative assumes more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass and Glass Products Manufacturing, and the natural gas-fired boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills relative to the final rule. Table 4-4 below provides a summary of the 2019 ozone season emissions for non-EGUs for the

[72] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668

20 states subject to the FIP in 2026, along with the estimated ozone season reductions for the final rule and the less and more stringent alternatives.

**Table 4-4. Ozone Season $NO_X$ Emissions and Emissions Reductions for the Final Rule and the Less and More Stringent Alternatives for Non-EGUs**

| State | 2019 Ozone Season Emissions[a] | Final Rule: Ozone Season NOx Reductions | Less Stringent: Ozone Season NOx Reductions | More Stringent: Ozone Season NOx Reductions[b] |
|---|---|---|---|---|
| AR | 8,790 | 1,546 | 457 | 1,690 |
| CA | 16,562 | 1,600 | 1,432 | 4,346 |
| IL | 15,821 | 2,311 | 751 | 2,991 |
| IN | 16,673 | 1,976 | 1,352 | 3,428 |
| KY | 10,134 | 2,665 | 583 | 3,120 |
| LA | 40,954 | 7,142 | 1,869 | 7,687 |
| MD | 2,818 | 157 | 147 | 1,145 |
| MI | 20,576 | 2,985 | 760 | 5,087 |
| MO | 11,237 | 2,065 | 579 | 4,716 |
| MS | 9,763 | 2,499 | 507 | 2,650 |
| NJ | 2,078 | 242 | 242 | 258 |
| NV | 2,544 | 0 | 0 | 0 |
| NY | 5,363 | 958 | 726 | 1,447 |
| OH | 18,000 | 3,105 | 1,031 | 4,006 |
| OK | 26,786 | 4,388 | 1,376 | 5,276 |
| PA | 14,919 | 2,184 | 1,656 | 4,550 |
| TX | 61,099 | 4,691 | 1,880 | 9,963 |
| UT | 4,232 | 252 | 52 | 615 |
| VA | 7,757 | 2,200 | 978 | 2,652 |
| WV | 6,318 | 1,649 | 408 | 2,100 |
| **Totals** | **302,425** | **44,616** | **16,786** | **67,728** |

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.
[b] Note that for some industries the more stringent alternative reflects assumed technologies (and estimated emissions reductions) that are not widely demonstrated in practice in the U.S.

## 4.2 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. The EPA used IPM to project likely future electricity market conditions with and without the Transport FIP for the 2015 ozone NAAQS.

IPM, developed by ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. Due to lack of lead time, the EPA does not allow IPM to build certain new capital investments such as new, unplanned natural gas or renewable capacity or new SCR or SNCR through the 2023 run year in response to the state emission budgets (i.e., retrofits, retirements or builds additional to those selected in the baseline are not allowed in 2023). The compliance analysis of the final rule and alternatives assumes new combustion controls in the 2023 analysis year (although the rule would require these in 2024). After 2023, this limit is relaxed, and the model is no longer prevented from undertaking these capital investments.

The EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[73]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model uses natural gas fuel supply curves and regional gas delivery costs (basis differentials) to simulate the fuel price associated with a given level of gas consumption within the system. These inputs are derived using ICF's Gas Market Model (GMM), a supply/demand equilibrium model of the North American gas market.[74]

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[73] Detailed information and documentation of EPA's Baseline run using IPM (v6), including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.

[74] See Chapter 8 of EPA's Baseline run using IPM v6 documentation, available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck, and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[75]

To estimate the annualized costs of additional capital investments in the power sector, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[76] It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.

The EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the Cross-State Air Pollution Rule (U.S. EPA, 2011), the Mercury and Air Toxics Standards (U.S. EPA, 2011a), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015), the Carbon Pollution Standards for New Power Plants (U.S. EPA, 2015a), the Cross-State Air Pollution Rule Update (U.S. EPA, 2016), the Affordable Clean Energy Rule (U.S. EPA, 2019), the Clean Power Plan Repeal (U.S. EPA, 2019), and the Revised Cross-State Air Pollution Update Rule (U.S. EPA, 2021). The EPA has also used IPM to estimate the air pollution

[75] See Chapter 7 of the IPM v6 documentation. The documentation for EPA's power sector modeling platform v6 - summer 2021 reference case consists of a comprehensive document for the Summer 2021 release of IPM v. 6.20 and is available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.

[76] See Chapter 10 of the documentation for EPA's power sector modeling platform v6 - summer 2021 reference case, available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case

reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014), Disposal of Coal Combustion Residuals from Electric Utilities (U.S. EPA, 2015b), Steam Electric Effluent Limitation Guidelines (ELG) (U.S. EPA, 2015c), and Steam Electric Reconsideration Rule (U.S. EPA, 2020).

The model and the EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in October 2014 U.S. EPA commissioned a peer review[77] of EPA Baseline run version 5.13 using the Integrated Planning Model. Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies.[78] The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 20 years. IPM has also been employed by states (e.g., for the Regional Greenhouse Gas Initiative, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

### 4.3 The EPA's Power Sector Modeling of the Baseline run and Three Regulatory Control Alternatives

The IPM "baseline run" for any regulatory impact analysis is a business-as-usual scenario that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. As such, an IPM baseline run represents an element of the baseline for this RIA.[79] The EPA frequently updates the IPM baseline run to reflect the latest

[77] See Response and Peer Review Report EPA Baseline run Version 5.13 Using IPM, available at: https://www.epa.gov/airmarkets/response-and-peer-review-report-epa-base-case-version-513-using-ipm.
[78] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act
[79] As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g., changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the proposed rule by firms and the public." (USEPA, 2010).

available electricity demand forecasts from the U.S. Energy Information Administration (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

### *4.3.1 The EPA's IPM Baseline run v.6.20*

For our analysis of the final Transport FIP for the 2015 ozone NAAQS, the EPA used an updated version of the Summer 2021 release of IPM version 6.20 to provide power sector emissions data for air quality modeling, as well as a companion updated database of EGU units (the National Electricity Energy Data System, or NEEDS, Summer 2022[80]) that is used in the EPA's modeling applications of IPM. The IPM Baseline run includes the CSAPR, CSAPR Update, and the Revised CSAPR Update, as well as the Mercury and Air Toxics Standards. The Baseline run also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.[81] While finalized in December 2021, the impacts of the 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards are not captured in the baseline; the rule includes requirements for model years 2023 through 2026. The impacts of the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review are also not captured in the baseline.[82] Additionally, the model was also updated to account for current elevated input fuel pricing, with natural gas prices in the 2023 and 2025 run years hardwired based on futures prices,[83] and coal prices escalated in the 2023 run year. The model runs for the main RIA analysis do not capture the impacts of the Inflation Reduction Act (IRA). Appendix 4A includes a representation of key IRA provisions in the baseline and under a scenario that includes the final rule as modeled here, along with the associated costs and emission reductions. The analysis of power sector cost and impacts presented in this chapter is based on a single IPM Baseline run, and represents incremental

[80] https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.20
[81] For a full list of modeled policy parameters, please see: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case
[82] Available at: https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for
[83] 2023 and 2025 Henry Hub gas prices were exogenously input based on the average of the daily values of the NYMEX Natural Gas Henry Hub Annual Strip over the 5/09/22 – 6/21/22 period, which reflected the most recent set of values available at the time of this analysis. Hence the price of natural gas in these run years is derived based on futures pricing and not a solved for output. Subsequent years reflect fundamentals-based pricing.

impacts projected solely as a result of compliance with the emissions budgets presented in Table 4-3. above and the backstop emission rate.

*4.3.2 Methodology for Evaluating the Regulatory Control Alternatives*

To estimate the costs, benefits, and economic and energy market impacts of the Transport FIP for the 2015 ozone NAAQS, the EPA conducted quantitative analysis of the three regulatory control alternatives: the Transport FIP for the 2015 ozone NAAQS emission budgets and a more and a less stringent alternative. Details about these regulatory control alternatives, including state-specific EGU $NO_X$ ozone-season emissions budgets for each alternative as analyzed in this RIA, are provided above in Section 4.1.

Before undertaking power sector analysis to evaluate compliance with the regulatory control alternatives, the EPA first considered available EGU $NO_X$ mitigation strategies that could be implemented for the 2023 ozone season. The EPA considered all widely-used EGU $NO_X$ control strategies: optimizing[84] $NO_X$ removal by existing operational selective catalytic reduction (SCRs) and turning on and optimizing existing idled SCRs; optimizing existing idled selective non-catalytic reduction (SNCRs); installation of (or upgrading to) state-of-the-art $NO_X$ combustion controls; and installing new SCRs and SNCRs. The EPA determined that affected EGUs within the 22 states could implement the $NO_X$ mitigation strategies based on optimization of existing controls for the 2023 ozone season.[85] (The final rule does not phase in reductions associated with upgraded combustion controls until 2024, but the modeling for this RIA assumes this control strategy in the 2023 run year.) After assessing the available NOx mitigation methods, this RIA projects the system-wide least-cost strategies for complying with the annual budgets and the backstop emission rate. Least-cost compliance may lead to the application of different control strategies at a given source compared to the particular control measure assumed for that source in the analysis used to calculate the budgets, which is in keeping with the cost-saving compliance flexibility afforded by this allowance trading program.

Within IPM, units are assigned $NO_x$ emission rates based on historical data. To account for changes in emission rates based on the seasonal operation of controls, each unit is assigned

[84] Optimization of controls refers to the process of fully operating controls in order to meet the "widely achievable emission rate" as outlined in the EGU $NO_X$ Mitigation Strategies Final Rule TSD.
[85] The analysis assumes that SNCR and SCR optimization and state-of-the-art combustion control installation is available starting in 2023 and is adopted by all units identified by the Engineering Analysis. This compliance choice is an exogenous input into IPM.

four modes of operation. When the model is run, IPM selects the appropriate mode for each season based on historical data (i.e., how the unit operated in the past), whether the unit is subject to any seasonal or annual NOx reduction requirements, and whether the unit installs any additional controls.[86] The rule's emission control requirements for EGUs only apply during the program's ozone season (May 1 through September 30).

Many of these mitigation strategies are captured within IPM. However, due to limitations on model size, IPMv.6.20 does not have the ability to endogenously determine whether to operate existing EGU post-combustion $NO_X$ controls (i.e., SCR or SNCR), optimize existing SCRs and SNCRs, and install combustion controls in response to a regulatory emissions requirement.[87] The treatment of these controls in the analyses are described in turn. The operating status of existing post-combustion $NO_X$ controls at a particular EGU in a model scenario is determined by the model user. In order to evaluate compliance with the regulatory alternatives, the EPA determined outside of IPM the operation of existing controls that are idle in the baseline that would be expected for compliance with each of the evaluated regulatory alternatives and for which model years they can feasibly be applied. The EPA considers a unit to have optimized use of an SCR if emissions rates are equal to (or below) the "widely achievable" rate of 0.08 lbs/MMBtu for coal steam units, 0.03 lbs/MMBtu for oil/gas and combustion turbine units, and 0.012 lb/MMBtu for combined cycle units.[88] Within IPM, units with partially operating or idled SCRs are defined as SCR-equipped units with ozone season $NO_X$ emission rates exceeding the optimized rates in the baseline run. These units had their emission rates lowered to the applicable "widely achievable" optimized emissions rate. These control options (optimizing partially operating SCR controls or turning on idled SCR controls) are achievable in 2023 and have a uniform control cost of $900 per ton (2016$) for coal units that partially operate their controls and $1,600 per ton (2016$) for coal units that have idled their controls, and $900 per ton (2016$) for the other identified sources. As explained below in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units or to their

[86] For details on the emission rate assumptions within the model, please refer to chapter 3 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.

[87] EGUs with idled SCR or SNCR in the Baseline run represent a small percentage (less than 10 percent) of the EGU fleet that is equipped with $NO_X$ post-combustion controls.

[88] For details on the derivation of this standard, please see preamble Section VI.B.1.

modeled heat rates. Under the proposed rule, 261 units are projected to fully run existing SCR controls in 2023 and in each year thereafter until the year the unit retires or at the end of the model period.

The EPA considers a unit to have optimized use of an SNCR if NOx emissions rates are equal to or less than the mode 2 rate from the NEEDS database (Summer 2021). As described in Chapter 3 of the EPA's power sector IPM Modeling Documentation, these backstop NOx mode rates are calculated from historical data and reflect operation of existing post-combustion controls. Mode 2 for SNCR-controlled coal units is intended to reflect the operation of that unit's post-combustion control based on prior years when that unit operated its control. Hence any units with existing SNCRs with NOx emission rates greater than their mode 2 rates in the 22-state region had their rates lowered to their mode 2 rates. These control options are achievable in 2023 and have a uniform control cost of $1,800 per ton (2016$). As explained below in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units. Under this rule, 44 units are projected to fully run existing SNCR controls in 2023 and in each year thereafter until the year the unit retires or at the end of the model period.

Finally, unit combustion control configurations listed in NEEDS were compared against Table 3-14 in the documentation for the EPA Power Sector Modeling Platform v.6.20 Summer 2021 Reference Case, which lists state-of-the-art combustion control configurations based on unit firing type. This allowed the EPA to identify units that would receive state-of-the-art combustion control upgrades in IPM. The EPA then followed the procedure in the EGU NOx Mitigation Strategies Final Rule TSD to calculate each of these unit's new $NO_X$ emission rate. These upgrades were assumed to occur in the 2023 run year (though the rule does not reflect them until 2024) and have a uniform control cost of $1,600 per ton (2016$). As explained below in Section 4.3.3, the costs associated with this measure are accounted for outside of the model, and no further adjustments were made inside the model to the variable and fixed operating cost of these units. Under this rule, nine units are projected to install state-of-the-art combustion controls in 2023 and operate them in each year thereafter until the year the unit retires or at the end of the model period. The book-life of the new combustion controls is assumed to be 15 years, hence the stream of costs from 2023-45 fully captures the cost of any incremental controls under the rule. The EGU $NO_X$ mitigation strategies that are assumed to operate or are available to reduce $NO_X$ in response to each of the regulatory control alternatives are shown in Table 4-2 above; more information about the estimated costs of these controls can be found in the EGU $NO_X$ Mitigation Strategies Final Rule TSD.

Under the final rule 8 GW of SCR installations are projected. Under the more stringent alternative 15 GW of SCR installations are projected. Under the less stringent alternative 8 GW of new SCR installations are projected. The book-life of the new SCRs is assumed to be 15 years, hence the stream of costs from 2023-45 fully captures the cost of any incremental controls under the rule. Under the final rule and less stringent alternative an incremental 13 GW of coal (63 units) retirements are projected by 2030. Under the more stringent alternative 8 GW of coal retirements are projected by 2030. The associated costs of retirement are fully captured within the total costs of this rule presented in the RIA.

In addition to the limitation on ozone season $NO_X$ emissions required by the EGU emissions budgets for the 22 states and the backstop emission rate, there are four important features of the allowance trading program represented in the model that may influence the level and location of $NO_X$ emissions from affected EGUs, including: the ability of affected EGUs to buy and sell $NO_X$ ozone season allowances from one another for compliance purposes; the ability of affected EGUs to bank $NO_X$ ozone season allowances for future use; the effect of limits on the total ozone season $NO_X$ emissions from affected EGUs in each state required by the assurance provisions; and the treatment of banked pre-2023 vintage $NO_X$ ozone season allowances issued under the Revised CSAPR Update now being revised under this rule. Each of these features of the ozone season allowance trading program is described below. The analysis does not explicitly capture the dynamic budget adjustments over time, but the forced operation of controls during the ozone season over the forecast period (even in the absence of binding mass limits) approximates this feature of the program design.

Affected EGUs are expected to choose the least-cost method of complying with the requirements of the allowance trading program, and the distribution of ozone season $NO_X$ emissions across affected EGUs is generally governed by this cost-minimizing behavior in the analysis. The total ozone season $NO_X$ emissions from affected EGUs in this analysis are limited to the amount allowed by the sum of the $NO_X$ budgets across the 22 states, the starting bank of allowances, and any additional allowances that are banked for future use. The number of banked allowances is influenced by the determination of whether (i) existing controls that are idle in the baseline run are turned on, (ii) it is less costly to abate ozone season $NO_X$ emissions in a current ozone season than to abate emissions in a later ozone season, and (iii) the restriction on the total size of the bank, which is 21 percent of the sum of the state emissions budgets for the current control period until 2030 (at which point it declines to 10.5%). Affected EGUs are expected to bank $NO_X$ ozone season allowances in the 2023 ozone season for use in a later ozone season. The model starts with an assumed bank level in 2023 (described below) and endogenously determines the bank in each subsequent year.

The rule allows pre-2023 vintage $NO_X$ ozone season allowances to be used for compliance with this rule. The sources that would be participants in a revised Group 3 Trading Program under this rule are transitioning from several different starting points – with some sources already in the Group 3 Trading Program under its current regulations, some sources coming from the Group 2 Trading Program, and some sources not currently participating in any seasonal $NO_X$ trading program. As described in Section VI.B.12 of the preamble, the EPA is transitioning provisions that differ across the sets of potentially affected sources based on the sources' different starting points. Based on the EPA's expectation of the size of the $NO_X$ allowance bank after the one-time conversion carried out pursuant to the terms of this rule, the treatment of these banked allowances is represented in the modeling as an additional 43,389 tons of $NO_X$ allowances, the equivalent of one year of the variability limit associated with the emission budgets, that may be used by affected EGUs during the 2023 ozone season or in later ozone seasons under the Transport FIP for the 2015 ozone NAAQS and the more and less stringent alternatives.

While there are no explicit limits on the exchange of allowances between affected EGUs and on the banking of 2023 and future-year vintage $NO_X$ ozone season allowances, the assurance provisions limit the amount of seasonal $NO_X$ emissions by affected EGUs in each of the 22 states. The assurance level limits affected EGU emissions over an ozone season to the state's $NO_X$ ozone season emissions budget plus an increment equal to 21 percent of each state's emissions budget. This increment is called the variability limit. See Section VI.B.5 of the preamble for a discussion of the purpose of the assurance provision and further detail about how the variability limits and assurance levels are determined. If a state exceeds its assurance level in a given year, sources within that state are assessed a 3-to-1 allowance surrender penalty on the excess tons. Section VI.B.5 of the preamble also explains how the EPA then determines which EGUs are subject to this surrender requirement. In the modeling, the assurance provisions are represented by a limit on the total ozone season $NO_X$ emissions that may be emitted by affected EGUs in each state, and thus the modeling does not permit affected EGUs to collectively emit beyond their respective state's assurance levels and thus incur penalties.

### *4.3.3 Methodology for Estimating Compliance Costs*

This section describes the EPA's approach to quantify estimated compliance costs in the power sector associated with the three illustrative regulatory control alternatives. These compliance costs include estimates projected directly by the model as well as calculations performed outside of the model that use IPM model inputs and methods. The model projections capture the costs associated with shifting generation to lower-$NO_X$ emitting EGUs. As discussed in the previous subsection, the costs of increasing the use and optimizing the performance of existing and operating SCRs and SNCRs,[89] and for installing or upgrading $NO_X$ combustion controls, were estimated outside of the model. The costs for these three $NO_X$ mitigation strategies are calculated based on IPM emissions projections and use the same $NO_X$ control cost equations used in IPM. Therefore, this estimate is consistent with modeled projections and provides the best available quantification of the costs of these $NO_X$ mitigation strategies.

The following steps summarize the EPA's methodology for estimating the component of compliance costs that are calculated outside of the model for the final rule alternative in 2023. Similar calculations are performed for every year in the forecast horizon[90]:

(1) In the model projections, identify all EGUs in the 22 states that can adopt the following $NO_X$ mitigation strategies (described in previous subsection):

- Fully operating existing SCRs
- Fully operating existing SNCRs
- Installing state-of-the-art combustion controls

(2) Estimate the total $NO_X$ reductions that are attributable to each of these strategies:

[89] This includes optimizing the performance of SCRs that were not operating.
[90] For more information on the derivation of costs and useful life of combustion controls, please see EGU $NO_X$ Mitigation Strategies Final Rule TSD.

- Fully operating existing SCRs at coal steam, oil/gas steam, combined cycle, and combustion turbine units: 5,314 tons
- Fully operating existing SNCRs: 1,192 tons
- Installing state-of-the-art combustion controls: 6,288 tons

(3) Estimate the average cost (in 2016$) associated with each of these strategies:[91]

- Fully operating existing SCRs at coal steam units, oil/gas steam, combined cycle, and combustion turbine units: $900/ton
- Fully operating existing SNCRs: $1,800/ton
- Installing state-of-the-art combustion controls: $1,600/ton

(4) Multiply (2) by (3) to estimate the total cost associated with each of these strategies.

Table 4-5 summarizes the results of this methodology for the final rule alternative in 2023.

**Table 4-5. Summary of Methodology for Calculating Compliance Costs Estimated Outside of IPM for the Transport FIP for the 2015 Ozone NAAQS, 2023 (2016$)**

| $NO_X$ Mitigation Strategy | $NO_X$ Ozone Season Emissions (tons) | Average Cost ($/ton) | Total Cost ($MM) |
|---|---|---|---|
| Optimize existing SCRs at coal steam, oil/gas, combined cycle, and combustion turbine units | 5,341 | 900 | 5 |
| Optimize existing SNCRs | 1,192 | 1,800 | 2 |
| Installing state- of-the-art combustion controls | 2,251 | 1,600 | 4 |

The EPA exogenously updated the emissions rates for the identified EGUs within the 22 states consistent with the set of controls determined for 2023-2025 within IPM. The model was updated to incorporate the emissions budgets identified for each case, and the first-year bank adjustment as outlined in Section 4.3.2. The backstop emission rate was also imposed on affected uncontrolled units as outlined in Table 4-2, either in 2025 (in the more stringent alternative) or in 2030 (in the final rule and less stringent alternatives), which forced units to choose to either retrofit or retire in either of those years, respectively.

The change in the reported power system production cost between the rule alternative model run and the baseline run was used to capture the cost of generation shifting and the cost of

[91] See EGU $NO_X$ Mitigation Strategies Proposed Rule TSD for derivation of cost-per-ton estimates for fully operating SCRs and upgrading to state-of-the-art combustion controls.

new SCR installations. The total costs of compliance with the regulatory control alternatives are estimated as the sum of the costs that are modeled within IPM and the costs that are calculated outside the model.

### 4.4 Estimating Emissions Units, Emissions Reductions, and Costs for Non-EGUs

For non-EGUs, the EPA developed an analytical framework to facilitate decisions about industries and emission unit types for inclusion in a proposed Transport FIP for the 2015 ozone NAAQS transport obligations. A February 28, 2022 memorandum, titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026*, documents the analytical framework used to identify industries and emission unit types included in the proposed FIP.[92] To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved state implementation plan (SIP) submittals, consent decrees, and permit limits. That evaluation is detailed in the *Non-EGU Sectors Technical Support Document (TSD)* prepared for the proposed FIP.[93] The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. Below is a summary of the adjustments and additions to the emissions requirements and limitations the EPA made between the proposed FIP and this final rule.

- For Pipeline Transportation of Natural Gas, the EPA is finalizing the same emissions limits as proposed; however, the EPA is adjusting the applicability criteria to exclude emergency engines. Further, to allow for the industry to install controls on the engines with the largest potential for emissions reductions at cost-effective thresholds, the final regulations allow for the use of facility-wide emissions averaging for engines in the industry.
- For Cement and Concrete Product Manufacturing, in the final rule the EPA has removed the daily source cap limit, which could have resulted in an artificially restrictive $NO_X$

[92] The memorandum is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.
[93] The TSD is available in the docket here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.

emissions limit for affected cement kilns due to lower operating periods resulting from to the COVID-19 pandemic.

- For Iron and Steel and Ferroalloy Manufacturing, the EPA is only finalizing a test-and-set requirement for reheat furnaces premised on the installation of low-$NO_X$ burners. By not finalizing the other proposed emissions limits that were likely to require the installation of SCR, the EPA has addressed the various concerns regarding the feasibility and cost-effectiveness of installation of the other proposed controls at other unit types at these facilities.
- For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions.
- For boilers in Iron and Steel and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills, the EPA is finalizing a low-use exemption to eliminate the need to install controls on low-use boilers that would have resulted in relatively small reductions.
- For municipal waste combustors in Solid Waste Combustors and Incinerators, the EPA is finalizing emissions limits, summarized in Table 4-1.

In the final rule, the EPA is requiring that controls be installed and operational by the 2026 ozone season, except where an individual source qualifies for a limited extension of time to comply based on a specific demonstration of necessity. Where an individual source submits a satisfactory demonstration that an extension of time to comply beyond 2026 is necessary, the EPA may grant an extension of up to one year for that source to fully implement the controls, after which the source may request and the EPA may grant an additional extension of up to two additional years for full compliance, where specific criteria are met. The EPA's evaluation of timing issues associated with this rule are further discussed in Section VI.A of the preamble. Because it is not possible to currently know which sources or how many may seek or be granted an extension of time to comply with the emissions limits, we assume in the RIA that all covered non-EGUs comply with the rule beginning in 2026.

With the exception of Solid Waste Combustors and Incinerators for each industry and emissions unit type, using a 2019 inventory prepared from the emissions inventory system (EIS) the EPA first estimated a list of emissions units captured by the applicability criteria for the final rule. For Solid Waste Combustors and Incinerators, the EPA estimated the list for MWCs using the 2019 inventory and the NEEDS-v6-summer-2021-reference-case workbook.[94] Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain control technologies could meet the final emissions limits.

Using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits (see Table 4-18 below), and information on control efficiencies and default cost/ton values from the CMDB[95], the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. For the final rule the EPA did not run the Control Strategy Tool (CoST) to estimate emissions reductions and costs and programmed the assessment using R.[96] The EPA did not estimate emissions reductions of $SO_2$, $PM_{2.5}$, $CO_2$ and other pollutants that may be associated with controls on non-EGU emissions units. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs* available in the docket.[97]

The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may be different than those estimated in this assessment; the estimated emissions reductions from and costs to meet the final rule emissions limits may be different than those estimated in this assessment. The reported total costs do not include the costs of

[94] Available here: https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.
[95] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.
[96] R is a free software environment for statistical computing and graphics. Additional information is available here: https://www.r-project.org/. The R code that processed the data to estimate the emissions reductions and costs is available upon request.
[97] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668

monitoring, recordkeeping, reporting, or testing. The EPA submitted an information collection request (ICR) to OMB associated with the monitoring, calibrating, recordkeeping, reporting, and testing activities required for non-EGU emissions units -- *ICR for the Final Rule, Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units*, EPA ICR No. 2705.01. The ICR is summarized in Section X.B.2 of the final rule preamble. The EPA estimates monitoring, recordkeeping, reporting, and testing costs of approximately $3.8 million per year on average for the first three years. These costs are not reflected in the cost estimates in Table 4-19 and Table 4-20 below.

## 4.5 Estimated Impacts of the Regulatory Control Alternatives

### *4.5.1 Emissions Reduction Assessment for EGUs*

As indicated in Chapter 1, the EGU $NO_X$ emissions reductions are presented in this RIA from 2023 through 2042 and are based on IPM projections. As outlined in Section 4.3.2 IPM is operating existing and newly installed controls seasonally based on historical operation patterns and seasonal and annual emission constraints within the model. Table 4-6 presents the estimated reduction in power sector $NO_X$ emissions resulting from compliance with the evaluated regulatory control alternatives (i.e., emissions budgets) in the 22 states, as well as the impact on other states. The emission reductions follow an expected pattern: the less stringent alternative produces smaller emissions reductions than the final rule emissions budgets, and the more stringent alternative results in more $NO_X$ emissions reductions.

**Table 4-6. EGU Ozone Season NOx Emissions and Emissions Changes for the Baseline run and the Regulatory Control Alternatives from 2023 - 2045[98]**

| Ozone Season NOx (thousand tons) | | Total Emissions | | | | Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | | Baseline run | Final Rule | Less-Stringent Alternative | More-Stringent Alternative | Final Rule | Less-Stringent Alternative | More-Stringent Alternative |
| 2023 | 22 States | 230 | 220 | 220 | 220 | -10 | -10 | -10 |
| | Other States | 143 | 143 | 143 | 143 | 0 | 0 | 0 |
| | Nationwide | 373 | 363 | 363 | 363 | -10 | -10 | -10 |
| 2024 | 22 States | 203 | 181 | 193 | 168 | -22 | -10 | -35 |
| | Other States | 128 | 129 | 128 | 130 | 1 | 0 | 2 |
| | Nationwide | 331 | 310 | 321 | 298 | -21 | -10 | -33 |
| 2025 | 22 States | 176 | 143 | 167 | 116 | -34 | -9 | -60 |
| | Other States | 113 | 115 | 113 | 117 | 2 | 0 | 4 |
| | Nationwide | 289 | 258 | 279 | 233 | -32 | -10 | -56 |
| 2026 | 22 States | 167 | 140 | 159 | 114 | -27 | -8 | -53 |
| | Other States | 107 | 109 | 107 | 110 | 2 | 0 | 3 |
| | Nationwide | 274 | 248 | 266 | 224 | -25 | -8 | -49 |
| 2027 | 22 States | 157 | 137 | 151 | 111 | -20 | -6 | -46 |
| | Other States | 101 | 103 | 101 | 104 | 2 | 0 | 3 |
| | Nationwide | 258 | 239 | 252 | 215 | -19 | -6 | -43 |
| 2028 | 22 States | 147 | 134 | 143 | 109 | -14 | -4 | -39 |
| | Other States | 95 | 96 | 95 | 97 | 2 | 0 | 3 |
| | Nationwide | 242 | 230 | 238 | 206 | -12 | -4 | -36 |
| 2030 | 22 States | 137 | 101 | 102 | 103 | -36 | -35 | -33 |
| | Other States | 91 | 93 | 94 | 94 | 2 | 3 | 3 |
| | Nationwide | 228 | 194 | 195 | 197 | -34 | -33 | -31 |
| 2035 | 22 States | 132 | 101 | 101 | 103 | -30 | -30 | -29 |
| | Other States | 88 | 89 | 89 | 90 | 1 | 1 | 2 |
| | Nationwide | 220 | 190 | 190 | 193 | -29 | -30 | -27 |
| 2040 | 22 States | 119 | 89 | 89 | 91 | -30 | -30 | -29 |
| | Other States | 79 | 79 | 79 | 79 | 0 | 0 | 0 |
| | Nationwide | 198 | 169 | 168 | 170 | -30 | -30 | -29 |
| 2045 | 22 States | 102 | 80 | 80 | 80 | -22 | -22 | -22 |
| | Other States | 76 | 76 | 76 | 76 | 0 | 0 | 0 |
| | Nationwide | 178 | 156 | 156 | 156 | -22 | -22 | -22 |

Within the compliance modeling, in addition to compliance with the mass budgets, emissions reductions are also driven by the assumption that units fully operate their controls

[98] This analysis is limited to the geographically contiguous lower 48 states.

during the ozone season. For units with existing controls, this is reflected in the achievement of the "widely achievable" rate as outlined in Section 4.3.2. For units that lack existing SCR controls, this is reflected in the decision to install new controls (which must be operated in the ozone season) or retire. The final rule and more stringent alternative feature identical Engineering Analysis derived budgets based on installation of SCRs in the 2025 run year in the 19-state region. However, the final rule alternative defers the backstop emission rate until the 2030 run year for units without SCRs, while the more stringent alternative assumes the backstop emission rate is imposed in the 2025 run year. The less stringent alternative imposes Engineering Analysis derived budgets based on installation of SCRs in the 2030 run year in the 19-state region, and the backstop emission rate taking effect in the 2030 run year.

Hence emission reductions are lower under the less stringent alternative compared to the final rule through 2030 (since the mass budget is less stringent). The more stringent alternative features the backstop emission rate in effect in the 2025 run year, for which the model is set up to constrain affected EGUs to retrofit or retire in the 2025 run year, driving higher abatement (and more SCR retrofits) than the final rule before 2030. However, in 2030, the modeling of the final rule and less stringent alternatives estimates more retirements relative to the more stringent alternative. The more stringent alternative extends the operating life of plants that chose to retrofit in 2025 rather than retire and therefore, in 2030 onwards, emissions reductions for the final rule and less stringent alternative are slightly greater, since budgets are the same and the backstop emission rate is also in effect in both scenarios. For details on the EGU emissions controls assumed in each of the regulatory control alternatives, please see Table 4-2.

The results of the EPA's analysis show that, with respect to compliance with the EGU $NO_X$ emission budgets in 2023, maximizing the use of existing operating SCRs provides the largest amount of ozone season $NO_X$ emission reductions (54 percent, affecting 261 units), installing state-of-the-art combustion controls provides the next highest levels of ozone season reductions (22 percent, affecting 9 units), while optimizing existing SNCRs (12 percent, affecting 44 units) and generation shifting (11 percent) make up the remaining ozone season $NO_X$ reductions. (Although the budgets are not set using generation shifting, the IPM modeling for the RIA allows generation shifting as a compliance strategy and thus some reductions associated with generation shifting are observed in this analysis.) Based on this analysis of how

EGUs are expected to comply with the Transport FIP for the 2015 ozone NAAQS, none of the Group 3 states are projected to exceed their variability limits, nor use a substantial number of allowances from the starting bank during the 2023-2042 period.[99]

In addition to the ozone season $NO_X$ reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels (i.e., co-pollutants) that result from compliance strategies to reduce seasonal NOx emissions. These other emissions include the annual total changes in emissions of NOx, $SO_2$, $CO_2$, and direct $PM_{2.5}$ emissions changes. The emissions reductions are presented in Table 4-7.

[99] As shown in Table 4-6, in 2023 and 2025 seasonal NOx emissions from affected EGUs in the Group 3 states are projected to emit at levels equal to or below the aggregated state budgets, and therefore (i) will not bank additional allowances, or (ii) on net, not use any banked allowances available at the end of the previous year or, in the case of 2023, from the starting bank.

**Table 4-7. EGU Annual Emissions and Emissions Changes for $NO_X$, $SO_2$, $PM_{2.5}$, and $CO_2$ for the Regulatory Control Alternatives for 2023-2045**

| Annual $NO_X$ (thousand tons) | | Total Emissions | | | | Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | | Baseline run | Final Rule | Less-Stringent Alternative | More-Stringent Alternative | Final Rule | Less-Stringent Alternative | More-Stringent Alternative |
| 2023 | 22 States | 561 | 546 | 546 | 546 | -15 | -15 | -15 |
| | Other States | 328 | 329 | 329 | 329 | 0 | 0 | 0 |
| | Nationwide | 889 | 874 | 875 | 874 | -15 | -15 | -15 |
| 2024 | 22 States | 491 | 464 | 476 | 429 | -26 | -15 | -62 |
| | Other States | 286 | 287 | 286 | 291 | 1 | 0 | 5 |
| | Nationwide | 777 | 752 | 762 | 720 | -25 | -15 | -57 |
| 2025 | 22 States | 420 | 383 | 406 | 312 | -38 | -14 | -108 |
| | Other States | 244 | 246 | 243 | 253 | 2 | -1 | 9 |
| | Nationwide | 664 | 629 | 649 | 566 | -35 | -15 | -99 |
| 2026 | 22 States | 398 | 367 | 386 | 301 | -31 | -12 | -96 |
| | Other States | 232 | 234 | 231 | 240 | 2 | -1 | 8 |
| | Nationwide | 630 | 601 | 617 | 541 | -29 | -12 | -88 |
| 2027 | 22 States | 375 | 351 | 366 | 290 | -24 | -9 | -85 |
| | Other States | 220 | 222 | 220 | 227 | 2 | 0 | 7 |
| | Nationwide | 595 | 573 | 586 | 517 | -22 | -9 | -78 |
| 2028 | 22 States | 353 | 336 | 346 | 279 | -17 | -7 | -73 |
| | Other States | 208 | 210 | 209 | 214 | 1 | 0 | 5 |
| | Nationwide | 561 | 545 | 554 | 493 | -16 | -7 | -68 |
| 2030 | 22 States | 324 | 261 | 262 | 270 | -64 | -62 | -54 |
| | Other States | 208 | 210 | 211 | 212 | 1 | 3 | 4 |
| | Nationwide | 533 | 471 | 473 | 482 | -62 | -59 | -50 |
| 2035 | 22 States | 304 | 254 | 254 | 259 | -49 | -49 | -44 |
| | Other States | 197 | 201 | 201 | 201 | 3 | 3 | 4 |
| | Nationwide | 501 | 455 | 455 | 460 | -46 | -46 | -41 |
| 2040 | 22 States | 267 | 221 | 221 | 225 | -46 | -46 | -41 |
| | Other States | 173 | 174 | 174 | 174 | 1 | 1 | 1 |
| | Nationwide | 440 | 395 | 395 | 400 | -45 | -45 | -40 |
| 2045 | 22 States | 218 | 195 | 195 | 197 | -23 | -23 | -22 |
| | Other States | 160 | 160 | 160 | 160 | 0 | 1 | 0 |
| | Nationwide | 378 | 355 | 356 | 357 | -23 | -22 | -21 |

| Annual $SO_2$ (thousand tons) | | Total Emissions | | | | Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | | Baseline run | Final Rule | Less-Stringent Alternative | More-Stringent Alternative | Final Rule | Less-Stringent Alternative | More-Stringent Alternative |
| 2023 | 22 States | 916 | 915 | 913 | 915 | -1 | -3 | -1 |
| | Other States | 279 | 279 | 279 | 279 | 0 | 0 | 0 |
| | Nationwide | 1195 | 1194 | 1192 | 1194 | -1 | -3 | -1 |
| 2024 | 22 States | 787 | 766 | 782 | 723 | -21 | -5 | -64 |
| | Other States | 239 | 240 | 239 | 243 | 1 | 0 | 4 |
| | Nationwide | 1025 | 1006 | 1021 | 966 | -19 | -5 | -59 |
| 2025 | 22 States | 657 | 617 | 651 | 531 | -40 | -6 | -127 |
| | Other States | 199 | 201 | 198 | 207 | 2 | -1 | 8 |
| | Nationwide | 856 | 818 | 849 | 738 | -38 | -7 | -118 |
| 2026 | 22 States | 574 | 543 | 569 | 463 | -31 | -5 | -111 |
| | Other States | 181 | 183 | 181 | 188 | 2 | 0 | 7 |
| | Nationwide | 755 | 726 | 750 | 651 | -29 | -5 | -104 |
| 2027 | 22 States | 491 | 469 | 487 | 395 | -22 | -4 | -96 |
| | Other States | 163 | 164 | 163 | 168 | 1 | 0 | 5 |
| | Nationwide | 654 | 633 | 650 | 563 | -21 | -4 | -91 |
| 2028 | 22 States | 408 | 395 | 405 | 327 | -13 | -3 | -80 |
| | Other States | 145 | 145 | 146 | 149 | 0 | 0 | 4 |
| | Nationwide | 553 | 540 | 551 | 476 | -13 | -2 | -77 |
| 2030 | 22 States | 385 | 289 | 283 | 330 | -95 | -102 | -54 |
| | Other States | 147 | 150 | 151 | 151 | 2 | 4 | 3 |
| | Nationwide | 532 | 439 | 434 | 481 | -93 | -98 | -51 |
| 2035 | 22 States | 366 | 342 | 344 | 349 | -24 | -22 | -16 |
| | Other States | 135 | 138 | 138 | 137 | 3 | 3 | 2 |
| | Nationwide | 501 | 480 | 482 | 486 | -21 | -19 | -15 |
| 2040 | 22 States | 305 | 279 | 279 | 294 | -26 | -26 | -12 |
| | Other States | 126 | 127 | 127 | 127 | 1 | 1 | 1 |
| | Nationwide | 432 | 406 | 406 | 420 | -25 | -25 | -11 |
| 2045 | 22 States | 220 | 206 | 206 | 214 | -15 | -14 | -6 |
| | Other States | 128 | 128 | 128 | 128 | 0 | 0 | 0 |
| | Nationwide | 349 | 334 | 334 | 342 | -15 | -15 | -7 |

| Annual $PM_{2.5}$ (thousand tons) | | Total Emissions | | | | Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | | **Baseline run** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** |
| 2023 | 22 States | 63 | 63 | 63 | 63 | 0 | 0 | 0 |
| | Other States | 40 | 40 | 40 | 40 | 0 | 0 | 0 |
| | Nationwide | 103 | 103 | 103 | 103 | 0 | 0 | 0 |
| 2024 | 22 States | 57 | 56 | 56 | 55 | -1 | 0 | -2 |
| | Other States | 36 | 36 | 36 | 37 | 0 | 0 | 1 |
| | Nationwide | 93 | 92 | 93 | 92 | -1 | 0 | -1 |
| 2025 | 22 States | 51 | 49 | 50 | 47 | -2 | -1 | -3 |
| | Other States | 33 | 33 | 33 | 34 | 0 | 0 | 1 |
| | Nationwide | 84 | 82 | 83 | 81 | -2 | -1 | -2 |
| 2026 | 22 States | 49 | 48 | 49 | 46 | -1 | 0 | -3 |
| | Other States | 33 | 33 | 33 | 34 | 0 | 0 | 1 |
| | Nationwide | 82 | 81 | 81 | 80 | -1 | 0 | -2 |
| 2027 | 22 States | 48 | 47 | 48 | 46 | -1 | 0 | -2 |
| | Other States | 32 | 32 | 32 | 33 | 0 | 0 | 1 |
| | Nationwide | 80 | 80 | 80 | 79 | -1 | 0 | -2 |
| 2028 | 22 States | 47 | 46 | 47 | 45 | 0 | 0 | -2 |
| | Other States | 32 | 32 | 32 | 33 | 0 | 0 | 1 |
| | Nationwide | 79 | 78 | 79 | 77 | 0 | 0 | -1 |
| 2030 | 22 States | 45 | 43 | 43 | 44 | -2 | -2 | 0 |
| | Other States | 32 | 32 | 32 | 32 | 0 | 0 | 0 |
| | Nationwide | 76 | 75 | 75 | 76 | -1 | -1 | 0 |
| 2035 | 22 States | 46 | 44 | 44 | 45 | -2 | -2 | -1 |
| | Other States | 30 | 30 | 30 | 30 | 0 | 0 | 0 |
| | Nationwide | 75 | 74 | 74 | 75 | -1 | -1 | 0 |
| 2040 | 22 States | 44 | 43 | 43 | 44 | -2 | -2 | 0 |
| | Other States | 28 | 28 | 28 | 28 | 0 | 0 | 0 |
| | Nationwide | 73 | 71 | 71 | 72 | -2 | -2 | 0 |
| 2045 | 22 States | 42 | 42 | 42 | 42 | 0 | 0 | 0 |
| | Other States | 28 | 28 | 28 | 28 | 0 | 0 | 0 |
| | Nationwide | 70 | 70 | 70 | 70 | 0 | 0 | 0 |

| Annual $CO_2$ (million short tons) | | Total Emissions | | | | Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | | Baseline run | Final Rule | Less-Stringent Alternative | More-Stringent Alternative | Final Rule | Less-Stringent Alternative | More-Stringent Alternative |
| 2023 | 22 States | 1033 | 1032 | 1032 | 1032 | 0 | 0 | 0 |
| | Other States | 591 | 592 | 592 | 591 | 0 | 0 | 0 |
| | Nationwide | 1624 | 1624 | 1624 | 1624 | 0 | 0 | 0 |
| 2024 | 22 States | 947 | 935 | 943 | 919 | -12 | -4 | -28 |
| | Other States | 539 | 541 | 540 | 548 | 2 | 0 | 8 |
| | Nationwide | 1487 | 1476 | 1483 | 1467 | -10 | -4 | -20 |
| 2025 | 22 States | 862 | 838 | 854 | 806 | -24 | -8 | -56 |
| | Other States | 488 | 491 | 488 | 504 | 3 | 0 | 17 |
| | Nationwide | 1350 | 1329 | 1342 | 1310 | -21 | -8 | -40 |
| 2026 | 22 States | 844 | 826 | 839 | 796 | -18 | -6 | -48 |
| | Other States | 477 | 480 | 477 | 492 | 3 | 0 | 15 |
| | Nationwide | 1322 | 1306 | 1316 | 1288 | -16 | -6 | -34 |
| 2027 | 22 States | 827 | 814 | 823 | 786 | -13 | -3 | -41 |
| | Other States | 467 | 469 | 467 | 480 | 2 | 0 | 13 |
| | Nationwide | 1294 | 1284 | 1290 | 1266 | -10 | -3 | -28 |
| 2028 | 22 States | 809 | 803 | 808 | 776 | -7 | -1 | -33 |
| | Other States | 457 | 459 | 457 | 468 | 2 | 0 | 12 |
| | Nationwide | 1266 | 1261 | 1265 | 1244 | -5 | -1 | -22 |
| 2030 | 22 States | 784 | 753 | 755 | 769 | -31 | -29 | -16 |
| | Other States | 450 | 455 | 456 | 458 | 5 | 6 | 7 |
| | Nationwide | 1235 | 1209 | 1211 | 1227 | -26 | -23 | -8 |
| 2035 | 22 States | 792 | 774 | 774 | 781 | -19 | -18 | -12 |
| | Other States | 436 | 438 | 438 | 439 | 2 | 3 | 3 |
| | Nationwide | 1228 | 1212 | 1213 | 1220 | -16 | -15 | -8 |
| 2040 | 22 States | 727 | 706 | 706 | 716 | -21 | -21 | -11 |
| | Other States | 411 | 411 | 412 | 412 | 1 | 1 | 1 |
| | Nationwide | 1138 | 1117 | 1117 | 1128 | -20 | -20 | -10 |
| 2045 | 22 States | 670 | 662 | 662 | 666 | -9 | -9 | -4 |
| | Other States | 400 | 400 | 400 | 400 | 0 | 0 | 0 |
| | Nationwide | 1070 | 1061 | 1062 | 1066 | -9 | -8 | -4 |

*4.5.2 Compliance Cost Assessment for EGUs*

The estimates of the changes in the cost of supplying electricity for the regulatory control alternatives are presented in Table 4-8.[100] Since the final rule does not result in any additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table.

**Table 4-8. National Power Sector Compliance Cost Estimates (millions of 2016$) for the Regulatory Control Alternatives**

| | Final Rule | More-Stringent Alternative | Less-Stringent Alternative |
|---|---|---|---|
| 2023-2027 (Annualized) | 14 | 677 | -19 |
| 2023-2045 (Annualized) | 449 | 645 | 446 |
| 2023 (Annual) | 57 | 49 | 56 |
| 2024 (Annual) | -5 | 835 | -35 |
| 2025 (Annual) | -5 | 835 | -35 |
| 2026 (Annual) | -5 | 835 | -35 |
| 2027 (Annual) | 24 | 762 | -47 |
| 2030 (Annual) | 705 | 835 | 772 |
| 2035 (Annual) | 817 | 592 | 847 |
| 2045 (Annual) | 182 | 251 | 168 |

"2023-2027 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2023 through 2027 and discounted using a 3.76 real discount rate.[101] This does not include compliance costs beyond 2027. "2023-2045 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2023 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. "2023 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those years.[102]

There are several notable aspects of the results presented in Table 4-8. One notable result is that the estimated annual compliance costs for the final rule and less stringent alternative are negative (i.e., a cost reduction) in 2023 through 2026, although this regulatory control alternative reduces $NO_X$ emissions by 40 thousand tons as shown in Table 4-6. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the

[100] Reported yearly costs reflect costs incurred in IPM run year mapped to respective calendar year. For details, please see Chapter 2 of the IPM documentation.
[101] This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual value over a 5-year period (2023-2027) and a 23-year period (2023-2045) using the 3.76% rate as well. Tables ES-15 and 8-7 report the NPV of the annual stream of costs from 2023-2042 using 3% and 7% consistent with OMB guidance.
[102] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

assumption of perfect foresight. IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period.[103] The specific reason for why costs are negative in these years for these two alternatives follows.

Under the final rule and more stringent alternative budgets assume SCR/SNCR optimization, state-of-the-art combustion control and SCR installations are selected by the 2025 run year. Under the less stringent alternative, budgets assume SCR/SNCR optimization, state-of-the-art combustion control by the 2025 run year, but SCR installation is not assumed until the 2030 run year. Under the final rule and the less stringent alternative, the backstop emission rate is imposed in the 2030 run year, while under the more stringent alternative, the backstop emission rate is imposed in the 2025 run year. In the case of the final rule and less stringent alternative, we see two waves of incremental coal retirement relative to the baseline – roughly 2 GW are retired in the 2025 run year (responding to tightening budgets), and an incremental 12 GW of retirements in the 2030 run year (responding to the backstop emission rate). In the case of the more stringent alternative, we see a single wave of an incremental 12 GW relative to the baseline in 2025.

The first wave of coal retirements reflects units that face challenging near-term conditions in the baseline but would have been more economically valuable later in the baseline forecast period, when demand growth and other firm retirements would improve their competitive position. Hence early retirement of this capacity in the final rule and less stringent alternative results in slightly lower near-term costs, but higher longer-term costs, and a point estimate of negative costs in a single year.[104] In the 2030 run year, the imposition of the backstop emission rate under the final rule and the less stringent alternative results in a greater amount of coal retirement reflective of projected economic preferences of unit owners/operators searching for least-cost compliance strategies. Under the more stringent alternative, the backstop emission rate

[103] For more information, please see Chapter 2 of the IPM documentation.
[104] As a sensitivity, the EPA re-calculated costs assuming annual costs cannot be negative. This resulted in annualized 2023-42 costs under the final rule increasing from $448.6 million to $449.5 million (less than 1%) and did not change the conclusions of this RIA.

is imposed in 2025, which results in a single wave of coal retirements and higher costs throughout the forecast period.

Under the final rule, operating existing SCR and SNCR controls and upgrading to state-of-the-art combustion controls provides a large share of the total emissions reductions in 2023. The model is constrained in 2023 to builds and retrofits that occurred in the baseline and features higher natural gas and coal prices reflecting near term trends. This means there is less flexibility to respond to the mass budgets, and costs are higher in 2023 than in 2025 and 2028, when fuel prices return to fundamentals and builds are not constrained to baseline levels. The imposition of the deferred backstop emission rate in 2030 results in retrofit/retirement decisions being made in that year as least-cost compliance strategies and fleet turnover as a result. Hence costs rise in 2030, and projected costs for the final rule peak in 2035 at $817 million (2016$) and annualized costs for the 2023-2045 period are $449 million (2016$). To put these costs into context, the incremental 2035 projected cost constitutes 0.6 percent of total projected baseline system production costs.

Under the more stringent alternative, while budgets are unchanged from the final rule, the backstop emission rate is imposed in the 2025 run year. In the model, affected units are required to retrofit/retire sooner, and costs peak in 2025 at $835 million as a result. The annualized costs over the 2023-2045 period are $645 million.

Under the less stringent alternative, the backstop emission rate is imposed in the 2030 run year consistent with the final rule, but mass budgets in the 2025 and 2028 run years are less stringent since they are based on Engineering Analysis that does not assume installation of new SCRs. Hence costs are lower in the 2025 and 2028 run years, before converging to final rule levels in 2030 and beyond. Costs peak in 2035 at $772 million as a result. The annualized costs over the 2023-2045 period are $446 million.

In addition to evaluating annual compliance cost impacts, the EPA believes that a full understanding of these three regulatory control alternatives benefits from an evaluation of annualized costs over the 2023-2027 timeframe. Starting with the estimated annual cost time series, it is possible to estimate the net present value of that stream, and then estimate a levelized annual cost associated with compliance with each regulatory control alternative.[105] For this analysis we first calculated the NPV of the stream of costs from 2023 through 2027[106] using a 3.76 percent discount rate. In this cost annualization we use a 3.76 percent discount rate, which is consistent with the rate used in IPM's objective function for minimizing the NPV of the stream of total costs of electricity generation. This discount rate is meant to capture the observed equilibrium market rate at which investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[107] After calculating the NPV of the cost streams, the same 3.76 percent discount rate and 2023-2027 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 4-8.[108] The same approach was used to develop the annualized cost estimates for the 2023-2045 timeframe. Additionally, note that the 2023-2027 and 2023-2045 equivalent annualized compliance cost estimates have the expected relationship to each other; the annualized costs are lowest for the less stringent alternative, and highest for the more stringent alternative.

*4.5.3 Impacts on Fuel Use, Prices and Generation Mix*

The Transport FIP for the 2015 ozone NAAQS is expected to result in significant $NO_X$ emissions reductions. It is also expected to have some impacts to the economics of the power sector. While these impacts are relatively small in percentage terms, consideration of these potential impacts is an important component of assessing the relative impact of the regulatory control alternatives. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, capacity by fuel type, and retail electricity prices for the 2023, 2025 and 2030 IPM model run years.

Table 4-9 and Table 4-10 present the percentage changes in national coal and natural gas usage by EGUs in the 2023, 2025, and 2030 run years. These fuel use estimates reflect a modest

[105] The XNPV() function in Microsoft Excel 2013 was used to calculate the NPV of the variable stream of costs, and the PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.
[106] Consistent with the relationship between IPM run years and calendar years, EPA assigned 2023 compliance cost estimates to both 2022 and 2023 in the calculation of NPV, and 2025 compliance cost to 2024 and 2025. For more information, see Chapter 7 of the IPM Documentation.
[107] The IPM Baseline run documentation (Section 10.4.1 Introduction to Discount Rate Calculations) states "The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 3.76%."
[108] The PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

shift to natural gas and renewables from coal in 2025 as a result of tightening budgets. In the 2025 run year, coal consumption reductions under the more stringent alternative are driven by increasing coal EGU retirements and reduced coal dispatch as a result of tightening budgets and the need to install SCR controls or retire uncontrolled units as shown in Table 4-14. To put these reductions into context, under the Baseline, power sector coal consumption is projected to decrease from 603 million tons in 2023 to 417 million tons in 2025 (15 percent annually), whereas under the final rule coal consumption is projected to decrease from 603 million tons in 2023 to 402 million tons in 2025 (17 percent annually). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.[109]

Under the more stringent alternative, the model projects a higher ratio of SCR retrofits to retirements, and the bulk of these changes occur in the 2025 run year as compared to the final rule and less stringent alternative when the majority of retirements and retrofits are projected to occur in 2030. This in turn results in higher costs in run year 2025 under the more stringent alternative, but comparatively lower costs in run year 2030. Under the less stringent alternative and final rule, cost impacts are projected to be lower in 2025 and higher in 2030. This in turn drives the differential impacts seen in the retail rate impacts.

**Table 4-9. 2023, 2025 and 2030 Projected U.S. Power Sector Coal Use for the Baseline and the Regulatory Control Alternatives**

| | | Million Tons | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|---|
| | **Year** | **Baseline** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** |
| Appalachia | 2023 | 121 | 121 | 121 | 121 | 0% | 0% | 0% |
| Interior | | 96 | 96 | 96 | 96 | 0% | 0% | 0% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% | 0% |
| West | | 382 | 382 | 382 | 382 | 0% | 0% | 0% |
| Total | | 603 | 603 | 603 | 603 | 0% | 0% | 0% |
| Appalachia | 2025 | 80 | 79 | 79 | 77 | -2% | -2% | -4% |
| Interior | | 76 | 75 | 76 | 71 | -1% | 0% | -7% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% | 0% |
| West | | 257 | 244 | 254 | 231 | -5% | -1% | -10% |
| Total | | 417 | 402 | 412 | 382 | -4% | -1% | -8% |

[109] US EIA Monthly Energy Review, Table 6.2, January 2022.

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Appalachia | 2030 | 49 | 47 | 47 | 48 | -4% | -3% | -2% |
| Interior | | 51 | 49 | 49 | 52 | -3% | -3% | 2% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% | 0% |
| West | | 170 | 154 | 155 | 160 | -10% | -9% | -6% |
| Total | | 274 | 254 | 256 | 265 | -7% | -7% | -4% |

**Table 4-10. 2023, 2025 and 2030 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Regulatory Control Alternatives**

| Trillion Cubic Feet | | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|
| **Year** | **Baseline** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** |
| 2023 | 7.7 | 7.7 | 7.7 | 7.7 | 0% | 0% | 0% |
| 2025 | 9.2 | 9.4 | 9.3 | 9.6 | 2% | 0% | 4% |
| 2030 | 12.2 | 12.4 | 12.4 | 12.4 | 1% | 1% | 1% |

Table 4-11 and Table 4-12 present the projected coal and natural gas prices in 2023, 2025 and 2030, as well as the percent change from the baseline run projected due to the regulatory control alternatives. These minor impacts in 2023 are consistent with the small changes in fuel use summarized above. The projected impacts in 2025 are larger in absolute value and consistent with tightening budgets.

**Table 4-11. 2023, 2025 and 2030 Projected Minemouth and Power Sector Delivered Coal Price (2016$) for the Baseline and the Regulatory Control Alternatives**

| | | $/MMBtu | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|---|
| | | **Baseline** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** |
| Minemouth | 2023 | 1.6 | 1.6 | 1.6 | 1.6 | 0% | 0% | 0% |
| Delivered | | 2.2 | 2.2 | 2.2 | 2.2 | 0% | 0% | 0% |
| Minemouth | 2025 | 1.1 | 1.1 | 1.1 | 1.2 | 0% | 0% | 1% |
| Delivered | | 1.7 | 1.7 | 1.7 | 1.7 | -1% | 0% | -1% |
| Minemouth | 2030 | 1.1 | 1.2 | 1.2 | 1.2 | 1% | 1% | 1% |
| Delivered | | 1.6 | 1.6 | 1.6 | 1.6 | -2% | -2% | -1% |

**Table 4-12. 2023, 2025 and 2030 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2016$) for the Baseline and the Regulatory Control Alternatives**

| | | $/MMBtu | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|---|
| | | **Baseline** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** |
| Henry Hub | 2023 | 4.8 | 4.8 | 4.8 | 4.8 | 0% | 0% | 0% |
| Delivered | | 4.9 | 4.9 | 4.9 | 4.9 | 0% | 0% | 0% |
| Henry Hub | 2025 | 3.4 | 3.4 | 3.4 | 3.4 | 0% | 0% | 0% |
| Delivered | | 3.5 | 3.5 | 3.5 | 3.5 | 0% | 0% | 0% |
| Henry Hub | 2030 | 2.7 | 2.7 | 2.7 | 2.7 | 0% | 1% | 0% |
| Delivered | | 2.8 | 2.8 | 2.8 | 2.8 | 0% | 1% | 0% |

Table 4-13 presents the projected percentage changes in the amount of electricity generation in 2023, 2025 and 2030 by fuel type. Consistent with the fuel use projections and emissions trends above, the EPA projects an overall shift from coal to gas and renewables. The projected impacts grow in 2025 reflecting the tightening budgets and are most pronounced in 2030 reflecting the imposition of the deferred backstop emission rate in the final rule.

**Table 4-13. 2023, 2025 and 20230 Projected U.S. Generation by Fuel Type for the Baseline and the Regulatory Control Alternatives**

| | | Generation (TWh) | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|---|
| | Year | **Baseline** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** |
| Coal | 2023 | 1,133 | 1,133 | 1,133 | 1,133 | 0% | 0% | 0% |
| Natural Gas | | 1,090 | 1,090 | 1,090 | 1,090 | 0% | 0% | 0% |
| Nuclear | | 775 | 775 | 775 | 775 | 0% | 0% | 0% |
| Hydro | | 289 | 289 | 289 | 289 | 0% | 0% | 0% |
| Non-Hydro RE | | 756 | 756 | 756 | 756 | 0% | 0% | 0% |
| Oil/Gas Steam | | 27 | 27 | 27 | 27 | 0% | 0% | 0% |
| Other | | 33 | 33 | 33 | 33 | 0% | 0% | 0% |
| Grand Total | | 4,103 | 4,103 | 4,103 | 4,103 | 0% | 0% | 0% |
| Coal | 2025 | 793 | 765 | 784 | 737 | -4% | -1% | -7% |
| Natural Gas | | 1,311 | 1,332 | 1,314 | 1,356 | 2% | 0% | 3% |
| Nuclear | | 724 | 724 | 724 | 724 | 0% | 0% | 0% |
| Hydro | | 294 | 295 | 295 | 295 | 0% | 0% | 0% |
| Non-Hydro RE | | 995 | 1,002 | 1,000 | 1,006 | 1% | 1% | 1% |
| Oil/Gas Steam | | 18 | 18 | 18 | 19 | -1% | -2% | 2% |
| Other | | 32 | 32 | 32 | 32 | 0% | 0% | 0% |

| | | Generation (TWh) | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|---|
| | Year | **Baseline** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** | **Final Rule** | **Less-Stringent Alternative** | **More-Stringent Alternative** |
| Grand Total | | 4,167 | 4,168 | 4,168 | 4,168 | 0% | 0% | 0% |
| Coal | 2030 | 523 | 489 | 492 | 507 | -7% | -6% | -3% |
| Natural Gas | | 1,691 | 1,710 | 1,709 | 1,708 | 1% | 1% | 1% |
| Nuclear | | 611 | 614 | 613 | 603 | 1% | 0% | -1% |
| Hydro | | 300 | 300 | 300 | 301 | 0% | 0% | 0% |
| Non-Hydro RE | | 1,111 | 1,122 | 1,121 | 1,116 | 1% | 1% | 0% |
| Oil/Gas Steam | | 22 | 22 | 22 | 23 | 0% | 0% | 4% |
| Other | | 32 | 32 | 32 | 32 | 0% | 0% | 0% |
| Grand Total | | 4,289 | 4,288 | 4,288 | 4,289 | 0% | 0% | 0% |

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind.

Table 4-14 presents the projected percentage changes in the amount of generating capacity in 2023, 2025 and 2030 by primary fuel type. As explained above, the baseline run was constrained to disallow endogenous retirement in 2023 to reflect near term limits. The policy scenarios were limited to add no more capacity economically than was added under the baseline in 2023 (also reflecting near term limits). These restrictions were removed in all subsequent run years. As a result, none of the regulatory control alternatives are expected to have a net impact on overall capacity by primary fuel type in 2023. By 2030 the rule is projected to result in an additional 14 GW of coal retirements nationwide relative to the baseline, reflecting utilities making least-cost decisions on how to achieve efficient compliance with the rule while maintaining sufficient generating capacity to ensure grid reliability.[110] This constitutes a reduction of 13 percent of national coal capacity, partially reflecting some earlier retirement that would otherwise have occurred later in the forecast period in the baseline. Under the baseline run, total coal retirements between 2023 and 2030 are projected to be 74 GW (or 10.6 GW annually). Under the final rule, total coal retirements between 2023 and 2030 are projected to be 89 GW (or 12.7 GW annually). This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020.[111]

[110] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy or grid reliability, see Section VI.B of the preamble, and the Reliability Assessment TSD included in the docket.
[111] See EIA's Today in Energy: https://www.eia.gov/todayinenergy/detail.php?id=50838.

Additionally, the rule is projected to incentivize an incremental 8 GW of SCR retrofit at coal plants. The rule is also projected to result in an incremental 3 GW of renewable capacity additions in 2025 (primarily consisting of solar capacity builds). These builds reflect early action, i.e., builds that would otherwise have occurred later in the forecast period. By 2035-40 total solar capacity equilibrates between the baseline and final rule alternatives.

**Table 4-14. 2023, 2025 and 2030 Projected U.S. Capacity by Fuel Type for the Baseline run and the Regulatory Control Alternatives**

| | | Capacity (GW) | | | | Percent Change from Baseline run | | |
|---|---|---|---|---|---|---|---|---|
| | Year | Baseline run | Final Rule | Less-Stringent Alt | More-Stringent Alt | Final Rule | Less-Stringent Alt | More-Stringent Alt |
| Coal | 2023 | 187 | 187 | 187 | 187 | 0% | 0% | 0% |
| Natural Gas | | 441 | 441 | 441 | 441 | 0% | 0% | 0% |
| Nuclear | | 97 | 97 | 97 | 97 | 0% | 0% | 0% |
| Hydro | | 102 | 102 | 102 | 102 | 0% | 0% | 0% |
| Non-Hydro RE | | 241 | 241 | 241 | 241 | 0% | 0% | 0% |
| Oil/Gas Steam | | 73 | 73 | 73 | 73 | 0% | 0% | 0% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% | 0% |
| Grand Total | | 1,148 | 1,148 | 1,148 | 1,148 | 0% | 0% | 0% |
| Coal | 2025 | 140 | 138 | 138 | 128 | -1% | -1% | -9% |
| Natural Gas | | 436 | 436 | 436 | 439 | 0% | 0% | 1% |
| Nuclear | | 91 | 91 | 91 | 91 | 0% | 0% | 0% |
| Hydro | | 102 | 102 | 102 | 102 | 0% | 0% | 0% |
| Non-Hydro RE | | 301 | 304 | 303 | 305 | 1% | 1% | 1% |
| Oil/Gas Steam | | 60 | 60 | 60 | 62 | 0% | 1% | 4% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% | 0% |
| Grand Total | | 1,135 | 1,137 | 1,136 | 1,133 | 0% | 0% | 0% |
| Coal | 2030 | 112 | 98 | 98 | 103 | -13% | -13% | -8% |
| Natural Gas | | 468 | 477 | 477 | 474 | 2% | 2% | 1% |
| Nuclear | | 76 | 76 | 76 | 75 | 1% | 0% | -1% |
| Hydro | | 103 | 103 | 103 | 103 | 0% | 0% | 0% |
| Non-Hydro RE | | 339 | 343 | 342 | 343 | 1% | 1% | 1% |
| Oil/Gas Steam | | 62 | 64 | 64 | 64 | 2% | 3% | 2% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% | 0% |
| Grand Total | | 1,168 | 1,168 | 1,167 | 1,168 | 0% | 0% | 0% |

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

The EPA estimated the change in the retail price of electricity (2016$) using the Retail Price Model (RPM).[112] The RPM was developed by ICF for the EPA and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and industrial) and regions, weighted by the amount of electricity used by each class and in each

[112] See documentation available at: https://www.epa.gov/airmarkets/retail-price-model

region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with EIA electricity market data for each of the 25 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).[113]

Table 4-15, Table 4-16, and Table 4-17 present the projected percentage changes in the retail price of electricity for the three regulatory control alternatives in 2023, 2025 and 2030, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to be small in 2023. In 2025, the EPA estimates that this rule will result in a less than 0.2 percent increase in national average retail electricity price, or by about 0.19 mills/kWh. In 2030, the EPA estimates that this rule will result in a 0.9% increase in national average retail electricity price, or by about 0.80 mills/KWh.

[113] See documentation available at: https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2020).pdf

**Table 4-15. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2023**

| All Sector | 2023 Average Retail Electricity Price (2016 mills/kWh) | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|
| **Region** | **Baseline** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** |
| TRE | 77.5 | 77.5 | 77.5 | 77.5 | 0% | 0% | 0% |
| FRCC | 109.1 | 109.1 | 109.1 | 109.1 | 0% | 0% | 0% |
| MISW | 98.4 | 98.4 | 98.4 | 98.4 | 0% | 0% | 0% |
| MISC | 93.2 | 93.2 | 93.2 | 93.2 | 0% | 0% | 0% |
| MISE | 89.8 | 89.8 | 89.8 | 89.8 | 0% | 0% | 0% |
| MISS | 84.6 | 84.6 | 84.6 | 84.6 | 0% | 0% | 0% |
| ISNE | 151.3 | 151.4 | 151.3 | 151.9 | 0% | 0% | 0% |
| NYCW | 680.1 | 684.4 | 683.4 | 696.4 | 1% | 0% | 2% |
| NYUP | 148.1 | 148.1 | 148.1 | 148.3 | 0% | 0% | 0% |
| PJME | 140.4 | 141.4 | 141.2 | 144.4 | 1% | 1% | 2% |
| PJMW | 93.2 | 93.2 | 93.2 | 93.3 | 0% | 0% | 0% |
| PJMC | 79.8 | 79.8 | 79.8 | 79.9 | 0% | 0% | 0% |
| PJMD | 73.9 | 73.9 | 73.8 | 74.0 | 0% | 0% | 0% |
| SRCA | 97.6 | 97.5 | 97.5 | 97.6 | 0% | 0% | 0% |
| SRSE | 104.4 | 104.4 | 104.4 | 104.4 | 0% | 0% | 0% |
| SRCE | 76.3 | 76.3 | 76.3 | 76.3 | 0% | 0% | 0% |
| SPPS | 79.9 | 79.9 | 79.9 | 80.0 | 0% | 0% | 0% |
| SPPC | 103.0 | 103.0 | 103.0 | 103.0 | 0% | 0% | 0% |
| SPPN | 63.6 | 63.6 | 63.6 | 63.6 | 0% | 0% | 0% |
| SRSG | 103.3 | 103.3 | 103.3 | 103.3 | 0% | 0% | 0% |
| CANO | 153.0 | 153.0 | 153.0 | 153.0 | 0% | 0% | 0% |
| CASO | 186.3 | 186.3 | 186.3 | 186.3 | 0% | 0% | 0% |
| NWPP | 72.7 | 72.7 | 72.7 | 72.7 | 0% | 0% | 0% |
| RMRG | 96.0 | 96.0 | 96.0 | 96.0 | 0% | 0% | 0% |
| BASN | 90.8 | 90.9 | 90.9 | 90.9 | 0% | 0% | 0% |
| NATIONAL | 113.0 | 113.2 | 113.1 | 113.6 | 0% | 0% | 0% |

**Table 4-16. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2025**

| All Sector | 2025 Average Retail Electricity Price (2016 mills/kWh) | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|
| **Region** | **Baseline** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** |
| TRE | 71.6 | 72.7 | 72.5 | 83.9 | 2% | 1% | 16% |
| FRCC | 98.1 | 98.1 | 98.1 | 98.1 | 0% | 0% | 0% |
| MISW | 94.7 | 94.7 | 94.7 | 95.3 | 0% | 0% | 1% |
| MISC | 87.6 | 87.5 | 87.4 | 89.8 | 0% | 0% | 3% |
| MISE | 79.1 | 79.9 | 79.8 | 84.8 | 1% | 1% | 6% |
| MISS | 77.6 | 77.9 | 77.6 | 79.4 | 0% | 0% | 2% |
| ISNE | 134.7 | 134.8 | 134.8 | 135.5 | 0% | 0% | 1% |
| NYCW | 180.1 | 180.3 | 180.1 | 180.7 | 0% | 0% | 0% |
| NYUP | 114.8 | 114.9 | 114.7 | 115.4 | 0% | 0% | 1% |
| PJME | 116.3 | 116.4 | 116.1 | 117.0 | 0% | 0% | 1% |
| PJMW | 86.3 | 86.7 | 86.4 | 90.6 | 0% | 0% | 5% |
| PJMC | 76.2 | 75.4 | 75.6 | 83.0 | -1% | -1% | 10% |
| PJMD | 67.2 | 67.5 | 67.3 | 71.4 | 0% | 0% | 6% |
| SRCA | 92.3 | 92.3 | 92.3 | 92.3 | 0% | 0% | 0% |
| SRSE | 95.4 | 95.4 | 95.4 | 95.0 | 0% | 0% | 0% |
| SRCE | 69.8 | 69.7 | 69.7 | 70.4 | 0% | 0% | 1% |
| SPPS | 76.7 | 77.1 | 76.8 | 79.4 | 0% | 0% | 3% |
| SPPC | 100.2 | 100.5 | 100.4 | 102.6 | 0% | 0% | 2% |
| SPPN | 63.0 | 62.7 | 62.9 | 61.6 | 0% | 0% | -2% |
| SRSG | 99.5 | 99.5 | 99.5 | 99.5 | 0% | 0% | 0% |
| CANO | 152.1 | 152.1 | 152.1 | 152.7 | 0% | 0% | 0% |
| CASO | 186.6 | 186.5 | 186.6 | 187.1 | 0% | 0% | 0% |
| NWPP | 72.2 | 72.2 | 72.2 | 72.4 | 0% | 0% | 0% |
| RMRG | 90.8 | 90.9 | 90.8 | 91.0 | 0% | 0% | 0% |
| BASN | 89.0 | 89.1 | 89.0 | 90.3 | 0% | 0% | 1% |
| NATIONAL | 95.6 | 95.7 | 95.6 | 98.0 | 0% | 0% | 2% |

**Table 4-17. Average Retail Electricity Price by Region for the Baseline and the Regulatory Control Alternatives, 2030**

| All Sector | 2030 Average Retail Electricity Price (2016 mills/kWh) | | | | Percent Change from Baseline | | |
|---|---|---|---|---|---|---|---|
| **Region** | **Baseline** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** | **Final Rule** | **Less-Stringent Alt.** | **More-Stringent Alt.** |
| TRE | 79.2 | 83.0 | 83.1 | 78.4 | 5% | 5% | -6% |
| FRCC | 92.5 | 92.5 | 92.6 | 92.5 | 0% | 0% | 0% |
| MISW | 90.6 | 90.6 | 90.7 | 90.6 | 0% | 0% | 0% |
| MISC | 86.0 | 86.6 | 86.6 | 86.9 | 1% | 1% | 0% |
| MISE | 102.1 | 102.0 | 102.1 | 102.0 | 0% | 0% | 0% |
| MISS | 75.8 | 77.1 | 77.1 | 76.3 | 2% | 2% | -1% |
| ISNE | 144.6 | 145.2 | 145.2 | 145.8 | 0% | 0% | 0% |
| NYCW | 190.3 | 192.1 | 192.2 | 194.1 | 1% | 1% | 1% |
| NYUP | 117.0 | 118.7 | 118.9 | 120.4 | 2% | 2% | 1% |
| PJME | 106.2 | 107.8 | 107.9 | 105.3 | 2% | 2% | -2% |
| PJMW | 91.9 | 92.5 | 92.5 | 92.0 | 1% | 1% | -1% |
| PJMC | 81.2 | 81.3 | 81.4 | 81.3 | 0% | 0% | 0% |
| PJMD | 75.7 | 76.8 | 76.9 | 76.7 | 1% | 2% | 0% |
| SRCA | 89.0 | 89.0 | 89.0 | 89.0 | 0% | 0% | 0% |
| SRSE | 88.4 | 88.4 | 88.4 | 88.4 | 0% | 0% | 0% |
| SRCE | 67.2 | 67.6 | 67.6 | 67.6 | 1% | 1% | 0% |
| SPPS | 77.3 | 77.9 | 78.0 | 78.2 | 1% | 1% | 0% |
| SPPC | 91.4 | 92.2 | 92.3 | 91.8 | 1% | 1% | -1% |
| SPPN | 63.3 | 63.0 | 63.0 | 63.2 | -1% | -1% | 0% |
| SRSG | 91.6 | 91.5 | 91.4 | 91.7 | 0% | 0% | 0% |
| CANO | 166.5 | 167.4 | 167.4 | 166.3 | 1% | 1% | -1% |
| CASO | 198.3 | 198.5 | 198.5 | 198.2 | 0% | 0% | 0% |
| NWPP | 72.6 | 72.5 | 72.5 | 72.5 | 0% | 0% | 0% |
| RMRG | 85.3 | 85.5 | 85.6 | 85.3 | 0% | 0% | 0% |
| BASN | 86.4 | 87.3 | 87.3 | 87.6 | 1% | 1% | 0% |
| NATIONAL | 96.1 | 96.9 | 97.0 | 96.3 | 1% | 1% | -1% |

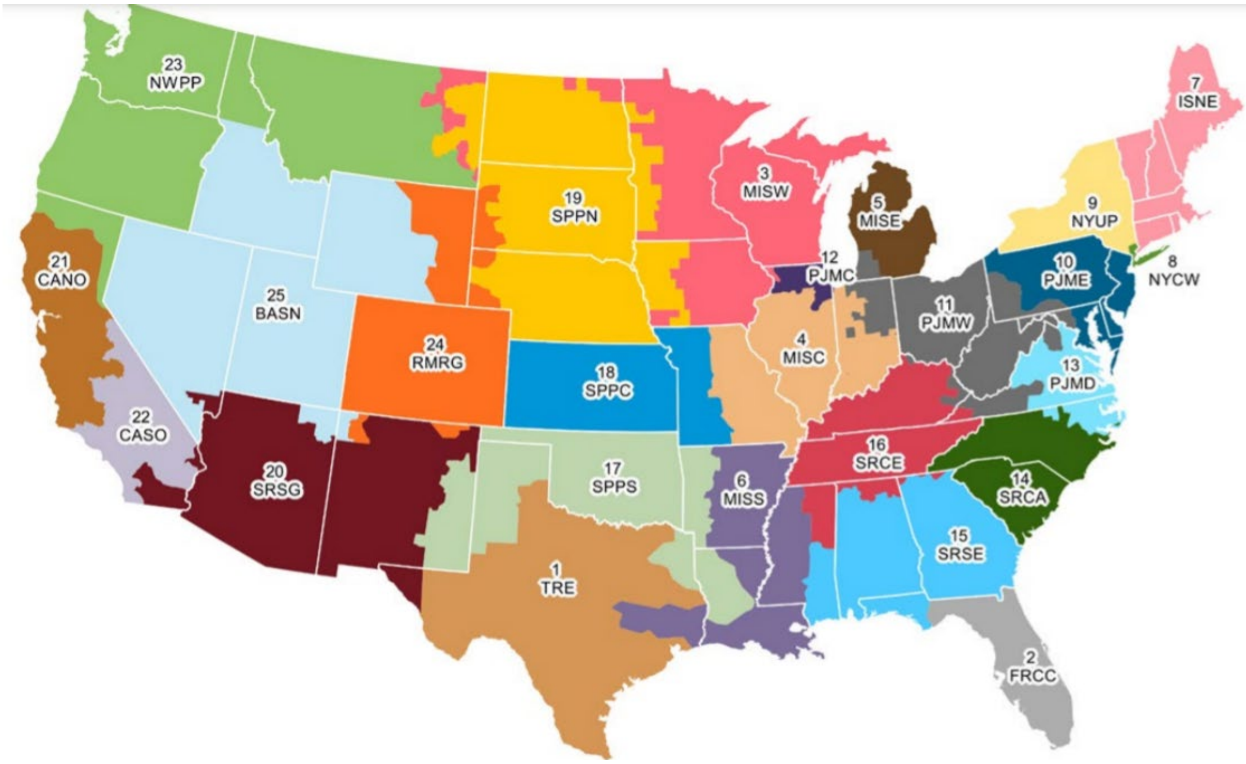


**Figure 4-1. Electricity Market Module Regions**
*Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)*

*4.5.4 Emissions Reductions and Compliance Cost Assessment for Non-EGUs for 2026*

As stated in Section 4.4, using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the CMDB, the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. The EPA did not estimate emissions reductions of $SO_2$, $PM_{2.5}$, $CO_2$ and other pollutants that may be associated with controls on non-EGU emissions units. Table 4-18 summarizes the industries, emissions unit types, control technologies, and number of emissions units estimated to be subject to the rule. The rule alternative includes an estimated 1,228 non-EGU emissions units. Table 4-19 summarizes the industries, emissions unit types, assumed control technologies, estimated annual total annual costs (2016$), and estimated ozone season emissions reductions for the rule. Table 4-20 summarizes the industries, emissions unit types, assumed control technologies, and estimated average annual costs (2016$). Lastly, Table 4-21 below summarizes the estimated reductions and estimated annual total and average annual costs (2016$) for the less and more stringent alternatives.

Because the Transport FIP for the 2015 ozone NAAQS includes ozone season emissions limits for the non-EGU emissions units and because we do not know if all affected sources will run controls year-round or only during ozone season, we include estimates of ozone season NOx emissions reductions and not annual estimates in Table 4-19 and Table 4-21. Note that some of the EGU controls are assumed to run year-round. Also, because the Transport FIP for the 2015 ozone NAAQS includes emissions limits, and the non-EGU assessment does not account for growth in the affected industries and capital turnover over time, the reductions are estimated to be the same each year over the period from 2026 to 2042.

For additional 2026 non-EGU assessment results -- including (i) by state and (ii) by state and industry, estimated emissions reductions and costs, see the memorandum in the docket titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs*.

**Table 4-18. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies that Meet Final Emissions Limits, Estimated Number of Control Installations**

| Industry/Industries | Emissions Unit Type | Assumed Control Technologies that Meet Final Emissions Limits | Estimated Number of Units Per Assumed Control |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engines | NSCR or Layered Combustion (Reciprocating) | 323 |
| | | Layered Combustion (2-cycle Lean Burn) | 394 |
| | | SCR (4-cycle Lean Burn) | 158 |
| | | NSCR (4-cycle Rich Burn) | 30 |
| Cement and Concrete Product Manufacturing | Kiln | SNCR | 16 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | LNB | 19 |
| Glass and Glass Product Manufacturing | Furnaces | LNB | 61 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Boilers | LNB + FGR (Gas, No Coal or Oil) | 151 |
| Metal Ore Mining | | SCR (Any Coal, Any Oil) | 15 |
| Basic Chemical Manufacturing | | | |

| Industry/Industries | Emissions Unit Type | Assumed Control Technologies that Meet Final Emissions Limits | Estimated Number of Units Per Assumed Control |
|---|---|---|---|
| Petroleum and Coal Products Manufacturing | | | |
| Pulp, Paper, and Paperboard Mills | | | |
| Solid Waste Combustors and Incinerators[a] | Combustors or Incinerators | ANSCR | 57 |
| | | $LN^{TM}$ and SNCR | 4 |
| | | **Total** | **1,228** |

[a] Twelve MWCs have existing controls, and we estimated these units will use more reagent in those controls to meet the final emissions limits.

### Table 4-19. Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Total Annual Costs (2016$), Estimated Ozone Season NOx Emissions Reductions in 2026

| Industry/Industries | Emissions Unit Type | Assumed Control Technologies that Meet Final Emissions Limits | Annual Costs (million 2016$) | Ozone Season Emissions Reductions |
|---|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engine | NSCR or Layered Combustion, Layered Combustion, SCR, NSCR | 385 | 32,247 |
| Cement and Concrete Product Manufacturing | Kiln | SNCR | 10.1 | 2,573 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | LNB | 3.58 | 408 |
| Glass and Glass Product Manufacturing | Furnaces | LNB | 7.05 | 3,129 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Boilers | SCR, LNB + FGR | 8.84 | 440 |
| Metal Ore Mining | | | 0.621 | 18 |
| Basic Chemical Manufacturing | | | 49.7 | 1,748 |
| Petroleum and Coal Products Manufacturing | | | 5.13 | 147 |
| Pulp, Paper, and Paperboard Mills | | | 62.3 | 1,836 |
| Solid Waste Combustors and Incinerators | Combustors or Incinerators | ANSCR or $LN^{TM}$ and SNCR | 38.9 | 2,071 |
| | | **Totals** | **572** | **44,616** |

**Table 4-20. Summary of Non-EGU Industries, Emissions Unit Types, Assumed Control Technologies, Estimated Average Cost/Ton (2016$)**

| Industry/Industries | Emissions Unit Type | Assumed Control Technologies that Meet Final Emissions Limits | Average Cost/Ton Values (2016$) |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | Reciprocating Internal Combustion Engine | NSCR or Layered Combustion, Layered Combustion, SCR, NSCR | 4,981 |
| Cement and Concrete Product Manufacturing | Kiln | SNCR | 1,632 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Reheat Furnaces | LNB | 3,656 |
| Glass and Glass Product Manufacturing | Furnaces | LNB | 939 |
| Iron and Steel Mills and Ferroalloy Manufacturing | Boilers | SCR or LNB + FGR | 8,369 |
| Metal Ore Mining | | | 14,595 |
| Basic Chemical Manufacturing | | | 11,845 |
| Petroleum and Coal Products Manufacturing | | | 14,582 |
| Pulp, Paper, and Paperboard Mills | | | 14,134 |
| Solid Waste Combustors and Incinerators | Combustors or Incinerators | ANSCR or LN™ and SNCR[a] | 7,836 |
| | | **Overall Average Cost/Ton** | **5,339** |

[a] Covanta has developed a proprietary low NOx combustion system (LNTM) that involves staging of combustion air. The system is a trademarked system and Covanta has received a patent for the technology.

**Table 4-21. Estimated Emissions Reductions for 2026-2042 (ozone season tons) and Estimated Annual Total Costs for the Less and More Stringent Alternatives**

| Alternative | Ozone Season NOx Emissions Reductions | Annual Total Cost (million 2016$) (Average Annual Cost/Ton) |
|---|---|---|
| **Less Stringent Alternative** | 16,786 | $144 ($3,573) |
| **More Stringent Alternative** | 67,958 | $1,280 ($7,852) |

### *4.5.5 Total Emissions Reductions and Compliance Costs for EGUs and Non-EGUs*

For select years between 2023 and 2042, Table 4-22 below summarizes the total estimated emissions reductions and undiscounted compliance costs for EGUs and non-EGUs for the final rule and the less and more stringent alternatives. For a complete stream of undiscounted cost values, please see Chapter 8, Table 8-6.

Table 4-23 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates for EGUs and non-EGUs for the final rule and the less and more stringent alternatives. We present the PV of the costs over the twenty-year period 2023 to 2042. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis.

**Table 4-22. Total Estimated $NO_x$ Emissions Reductions (ozone season, thousand tons) and Compliance Costs (million 2016$), 2023-2042**

| | | Final Rule | Less Stringent Alternative | More Stringent Alternative | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|---|---|---|---|
| | | Emissions Reductions (ozone season, thousand tons) | | | Compliance Costs (million 2016$) | | |
| 2023 | EGUs | 10 | 10 | 10 | 57 | 56 | 49 |
| | Non-EGUs | -- | -- | -- | - | - | - |
| | **Total** | **10** | **10** | **10** | **57** | **56** | **49** |
| 2026 | EGUs | 27 | 8 | 53 | (5) | (35) | 840 |
| | Non-EGUs | 45 | 17 | 68 | 570 | 140 | 1,300 |
| | **Total** | **72** | **25** | **121** | **570** | **110** | **2,100** |
| 2027 | EGUs | 20 | 6 | 46 | 24 | (47) | 760 |
| | Non-EGUs | 45 | 17 | 68 | 570 | 140 | 1,300 |
| | **Total** | **65** | **23** | **114** | **600** | **97** | **2,000** |
| 2030 | EGUs | 36 | 35 | 33 | 710 | 770 | 840 |
| | Non-EGUs | 45 | 17 | 68 | 570 | 140 | 1,300 |
| | **Total** | **81** | **52** | **101** | **1,300** | **920** | **2,100** |
| 2035 | EGUs | 30 | 30 | 29 | 820 | 850 | 590 |
| | Non-EGUs | 45 | 17 | 68 | 570 | 140 | 1,300 |
| | **Total** | **75** | **47** | **97** | **1,400** | **990** | **1,900** |
| 2042 | EGUs | 30 | 30 | 29 | 820 | 830 | 600 |
| | Non-EGUs | 45 | 17 | 68 | 570 | 140 | 1,300 |
| | **Total** | **75** | **47** | **97** | **1,400** | **970** | **1,900** |

**Table 4-23. Total National Compliance Cost Estimates (millions of 2016$) for the Final Rule and the Less and More Stringent Alternatives**

| | Final Rule | | Less Stringent Alternative | | More Stringent Alternative | |
|---|---|---|---|---|---|---|
| | 3 Percent | 7 Percent | 3 Percent | 7 Percent | 3 Percent | 7 Percent |
| Present Value EGU 2023-2042 | $6,800 | $3,900 | $6,800 | $3,900 | $9,500 | $6,500 |
| Present Value Non-EGU 2023-2042 | $6,700 | $4,300 | $1,700 | $1,100 | $15,000 | $9,500 |
| **Present Value Total 2023-2042** | **$13,000** | **$8,200** | **$8,500** | **$5,000** | **$24,000** | **$16,000** |
| EGU Equivalent Annualized Value | $460 | $370 | $460 | $370 | $640 | $620 |
| Non-EGU Equivalent Annualized Value | $450 | $400 | $110 | $100 | $1,000 | $900 |
| **Total Equivalent Annualized Value** | **$910** | **$770** | **$570** | **$470** | **$1,600** | **$1,500** |

Note: Values have been rounded to two significant figures

## 4.6 Social Costs

As discussed in the EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (U.S. EPA, 2010). This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed because of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected because of a regulation to assess its net impact on society.

The social costs of this regulatory action will not necessarily be equal to the expenditures by the electricity sector and other affected industries to comply with the final rule. Nonetheless, here we use total national compliance costs for EGUs and non-EGUs as a proxy for social costs. Table  above presents the total annual estimated compliance costs for EGUs for 2023 and EGUs and non-EGUs for 2026-2042.

The compliance cost estimates for EGUs in the rule and more or less stringent regulatory control alternatives presented above are the change in expenditures by the electricity generating sector required by the power sector for compliance under each alternative. The change in the expenditures required by the power sector to achieve and maintain compliance reflect the changes in electricity production costs resulting from application of $NO_X$ control strategies necessary to comply with the emissions budgets and the backstop emission rate. The production cost changes include changes in fuel expenditures.

Ultimately, depending on the market structure and the demand and supply price elasticities for electricity, some compliance costs may be borne by electricity consumers through higher electricity prices. Furthermore, the share of compliance costs ultimately borne by owners of electricity generating capacity and other capital may be borne unevenly, with some firms becoming more profitable as a result of the regulation. These asset owners and electricity consumers include U.S. citizens and residents as well as non-residents (e.g., foreign owners of electricity-consuming commercial enterprises). For additional discussion of impacts on fuel use and electricity prices, see Section 4.5.3 above.

The compliance cost estimates for non-EGUs in the rule and more or less stringent regulatory control alternatives are the change in expenditures by the industries required for compliance under each alternative. The change in the expenditures required by the industries to maintain compliance reflect the changes in production costs resulting from application of $NO_X$ control technologies or measures. As in the power sector, ultimately, depending on market structure and the demand and supply price elasticities for these industrial products, some part of the compliance costs may be borne by consumers through higher prices, and these costs are distributed among U.S. citizens and residents and foreign asset owners.

For non-EGUs the estimated compliance costs in Table 4-22 are derived using the control measures database, and for EGUs the estimated compliance costs are generated using the Integrated Planning Model (IPM). IPM solves for the least-cost approach to meet new regulatory requirements in the electricity sector with highly detailed information on electricity generation and air pollution control technologies and primary energy sector market conditions (coal and natural gas) while meeting fixed electricity demands, regulatory requirements, and other constraints. However, potential effects outside of the electricity, coal and natural gas sectors are not evaluated within IPM.

Changes in production in a directly regulated sector may have indirect effects on a myriad of other markets when output from that sector – for this rule electricity and certain industrial products - is used as an input in the production of many other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices.

When new regulatory requirements are expected to result in effects outside of regulated and closely related sectors, a key challenge is determining whether they are of sufficient magnitude to warrant explicit evaluation (Hahn and Hird 1990). It is not possible to estimate the magnitude and direction of these potential effects outside of the regulated sector(s) without an economy-wide modeling approach. For example, studies of air pollution regulations for the power sector have found that the social costs and benefits may be greater or lower than when secondary market impacts are considered, and that the direction of the estimates may depend on the form of the regulation (e.g., Goulder et al. 1999, Williams 2002, Goulder et al. 2016).

Economy-wide models - and, more specifically, computable general equilibrium (CGE) models - are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy. It is structured around the assumption that, for some discrete period of time, an economy can be characterized by a set of equilibrium conditions in which supply equals demand in all markets. When the imposition of a regulation alters conditions in one market, a general equilibrium approach will determine a new set of prices for all markets that will return the economy to equilibrium. These prices in turn determine the outputs and consumption of goods and services in the new equilibrium. In addition, a new set of prices and demands for the factors of production (labor, capital, and land), the returns to which compose the income of businesses and households, will be determined in general equilibrium. The social cost of the regulation can then be estimated by comparing the value of variables in the pre-regulation "baseline" equilibrium with those in the post-regulation, simulated equilibrium.

In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory development. In its final report (U.S. EPA 2017), the SAB recommended that the EPA begin to integrate CGE modeling into regulatory analysis to offer a more comprehensive assessment of the effects of air regulations. The SAB noted that CGE models can provide insight into the likely social costs of a regulation even when they do not include a characterization of the likely social benefits of the regulation. CGE models may also offer insights into the ways costs are distributed across regions, sectors, or households.

The SAB also noted that the case for using CGE models to evaluate a regulation's effects is strongest when the costs of compliance are expected to be large in magnitude and the sector has strong linkages to the rest of the economy. The report also noted that the extent to which CGE models add value to the analysis depends on data availability. CGE models provide aggregated representations of the entire economy and are designed to capture substitution possibilities between production, consumption, and trade; interactions between economic sectors; and interactions between a policy shock and pre-existing distortions, such as taxes. However, one also needs to adequately represent a regulation in the model to estimate its effects.

In response to the SAB's recommendations, the EPA built a new CGE model called SAGE. A second SAB panel performed a peer review of SAGE, and the reviewed concluded in 2020.[114] While the EPA now has a peer reviewed CGE model for analyzing the potential economy-wide effects of regulations, we have not used the model in the RIA for this rule due to the expedited rulemaking timeline. However, the EPA continues to be committed to the use of CGE models to evaluate the economy-wide effects of its regulations.

### 4.7 Limitations

The EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are uncertain. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls and new capacity construction costs to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions for EGUs. The annualized cost of the rule for EGUs, as quantified here, is the EPA's best assessment of the cost of implementing the rule for

[114] See U.S. EPA (2020). The model peer review and other SAB reports can be downloaded at: https://sab.epa.gov/ords/sab/f?p=100:12:15036376991605:::12::

the power sector. These costs are generated from rigorous economic modeling of changes in the power sector due to implementation of the rule.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the rule. To estimate these annualized costs, as discussed earlier in this chapter, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses to calculate annual costs. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are the EPA's best estimate of the direct private compliance costs of the rule.

In addition, there are several key areas of uncertainty related to the electric power sector that are worth noting, including:

- Electric demand: The analysis includes an assumption for future electric demand. To the extent electric demand is higher and lower, it may increase/decrease the projected future composition of the fleet.
- Natural gas supply and demand: The recent run up in fuel costs is reflected through an increase in natural gas price inputs for 2023 and 2025 model run years, and coal price inputs in the 2023 model run year. Large increases in supply over the last few years, and relatively low prices, are represented in the analysis for subsequent run years. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units).
- Longer-term planning by utilities: Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements, some of which are not legally binding, are not necessarily reflected in the baseline, and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.
- Inflation Reduction Act (IRA): The IRA was passed in August of 2022, at which time the modeling in support of this rule was in an advanced stage and timing considerations did

not allow for incorporation of the effects of this legislation. In order to illustrate the impact of the IRA on this rulemaking, the EPA included a baseline that incorporates key provisions of the IRA as well as imposing the final rule as modeled in this RIA on that baseline. The results from these scenarios are compared with the non-IRA scenarios and provided in Appendix 4A. The analysis quantifies total costs and emission changes but does not quantify the benefits associated with these emission changes.

These are key uncertainties that may affect the overall composition of electric power generation fleet and could thus have an effect on the estimated costs and impacts of this action. However, these uncertainties would affect the modeling of the baseline and illustrative policy alternatives similarly, and therefore the impact on the incremental projections (reflecting the potential costs/benefits of the illustrative final rule alternative) would be more limited and are not likely to result in notable changes to the assessment of the Transport FIP for the 2015 ozone NAAQS found in this chapter. While it is important to recognize these key areas of uncertainty, they do not change the EPA's overall confidence in the estimated impacts of the illustrative final rule alternative presented in this chapter. The EPA continues to monitor industry developments and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

The baseline includes modeling to capture the finalized 2020 Effluent Limitation Guidelines (ELG), it also incorporates information provided by owners of affected facilities to state permitting authorities in October 2021 that indicate their likely compliance pathway, including retirement by 2028. Potential future incorporation of this information may result in additional coal plant retirements relative to the baseline scenario, which would - all else equal - reduce the modeled costs and benefits of the rule depending on the extent that these retirements occur before compliance deadlines for this action. Similarly, the baseline accounts for the effect of expected compliance methods for the 2020 CCR Rule. However, plants may adopt compliance methods that are different than those represented in the baseline.

As discussed in section 4.3.2, IPM v.6.20 does not have the capacity to endogenously determine whether to maximize the use of existing EGU post-combustion $NO_X$ controls (i.e., SCR), or install/upgrade combustion controls in response to a regulatory control requirement.

These decisions were imposed exogenously on the model, as documented in section 4.3.2. While the emissions projections reflect operation of these controls, the projected compliance costs were supplemented with exogenously estimated costs of optimizing SCR operation, optimizing SNCR operation, and installing/upgrading combustion controls (see section 4.3.3). As a result of this modeling approach, the dispatch decisions made within the model do not take into consideration the additional operating costs associated with these three types of compliance strategies (the operating costs of the units on which these strategies are imposed do not reflect the additional costs of these strategies). The effect of changes in facility and system-wide emissions from these changes in operating costs are also not accounted for in the air quality modeling for the regulatory alternatives described in Chapter 3.

The impacts of the Later Model Year Light-Duty Vehicle GHG Emissions Standards[115] is not captured in the baseline. This rule is projected to increase the total demand for electricity by 0.5% in 2030 and 1% in 2040 relative to 2020 levels.[116] This translates into a 0.4% increase in electricity demand in 2030 and a 0.8% increase in electricity demand in 2040 relative to the baseline electricity demand projections assumed in this analysis. The impact of the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review[117] are also not included in this analysis. Inclusion of these standards would likely increase the price of natural gas modestly as a result of limitations on the usage of reciprocating internal combustion engines in the pipeline transportation of natural gas. All else equal inclusion of these two programs would likely result in a modest increase in the total cost of compliance for this rule.

Lastly, the EPA estimated the non-EGU emissions units subject to the final rule using the 2019 inventory from the emissions inventory system (EIS) and supplemented the information by reviewing online permits for the estimated emissions units in the Cement and Concrete Product Manufacturing, Glass and Glass Product Manufacturing, and Iron and Steel Mills and Ferroalloy Manufacturing industries. Because the number of estimated emissions units for reciprocating

[115] Available at: https://www.federalregister.gov/documents/2021/08/10/2021-16582/revised-2023-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-standards
[116] Regulatory Impact Analysis available at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1012ONB.pdf
[117] Available at: https://www.federalregister.gov/documents/2021/11/15/2021-24202/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

internal combustion engines and boilers was larger, the EPA did a limited permit review for those units. For boilers, the EPA also reviewed the database used in the July 2022 revised Boiler MACT. Using the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the CMDB, the EPA estimated $NO_X$ emissions reductions and costs for the year 2026. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions reductions and costs associated with the assumed control technologies that would meet the final emissions limits.[118] The control cost estimates assume an average level of retrofit difficulty for control applications, and do not include monitoring, recordkeeping, reporting, or testing costs. It is not possible to determine whether this approach leads to an overestimate or underestimate of the costs, NOx, and other pollutant emissions changes, benefits, and other impacts, including the effect on downwind receptors, of the rule and the analyzed alternatives. Between proposal and the final rule, based on comments received and additional research about whether a unit already had an existing control, the EPA updated the estimated emissions reductions and costs reflecting this information. For the final rule, if the EPA was aware of the presence of a control, in many cases it then assumed that the unit did not need additional control. And, if it was not aware of the presence of a control, it assumed that a control was required, and the costs and benefits were accounted for based on this approach.

We are not able to project potential changes in the number of existing and new units resulting from industry growth or capital turnover, over time in the baseline. The effects of the uncertainty in these changes on costs, emissions reductions and benefits of the final rule are ambiguous. We are also not able to project whether the emissions limitations would require further NOx emissions reductions at new units relative to what is required of them in the baseline.

Also, we are not able to project whether non-EGU units will make operational changes for compliance with the final rule and whether those changes will lead to changes in emissions other

[118] The EPA did not run the Control Strategy Tool to estimate emissions reductions and costs and programmed the assessment using R. R is a free software environment for statistical computing and graphics. Additional information is available here: https://www.r-project.org/. The R code that processed the data to estimate the emissions reductions and costs is available upon request.

than $NO_X$. For example, if the non-EGUs respond to this final rule by replacing an old unit with a newer, more efficient unit, emissions of other pollutants from non-EGUs may also decrease. Furthermore, certain non-EGUs may choose compliance approaches for the final rule that also incidentally reduce NOx emissions outside of the ozone season, which would yield additional benefits from reduced $PM_{2.5}$ exposure. If ultimate compliance with this final rule incidentally reduces NOx and other pollutants emissions outside of the ozone season, the benefits from non-EGUs, all else equal, are likely underestimated.

### 4.8 References


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# APPENDIX 4A: INFLATION REDUCTION ACT EGU SENSITIVITY RUN RESULTS

In this appendix we describe the EGU compliance behavior, costs, and emissions reductions that include adjustments made to the IPM baseline for the Inflation Reduction Act (IRA) of 2022. The IRA includes significant additional new generation incentives targeting more efficient and lower-emitting sources of generation that is likely to meaningfully affect the U.S. generation mix in the future and increase the pace of new lower-emitting generation replacing some of older higher-emitting generating capacity. This supplementary analysis quantifies the incremental impacts of the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) under the alternative baseline characterization and compares impacts with the main analysis described in Chapter 4. As described in Chapter 4, the model runs that inform air quality do not include the IRA due to time limitations. However, for completeness this appendix seeks to quantify the effect on the expected power sector outcomes of the final rule with this alternative baseline.

## 4A.1 Modeling the IRA in IPM

This supplementary analysis incorporates several key aspects of the IRA that influence EGU behavior in the IPM baseline. The analysis addresses aspects of the IRA to the extent possible given overall timing limitations in the production of this RIA and uncertainties around some of the final rule's potential impacts. The main IPM model updates are included in Table 4A.1. No adjustments are made to electricity demand to reflect the impact of incremental electrification, since this parameter is subject to a significant amount of uncertainty and is more likely to drive results later in the forecasted period.

**Table 4A-1. IRA Provisions Modeled in IPM**

| |
|---|
| **PTC/ITC and Clean Energy Tax Credits**<br>• Wage and apprenticeship requirements are assumed to be met.<br>• Extended to include stand-alone storage and new nuclear resources.<br>• All storage assumed to qualify for 10% bonus energy tax credit.<br>• All other technologies assumed to qualify for a prorated bonus energy tax credit based on the share of energy community land area to total land area within an IPM zone.<br>• Credits remain in place until later of 2032 or the year in which power sector emissions are 25% or less of 2021 historical levels (used as a proxy for 2022 emissions).<br><br>**Capital Cost Step Adder Adjustment**<br>• The short-term capital cost adder step widths for solar, wind, geothermal, hydro, and nuclear technologies are relaxed to reflect the IRA's impact on improvements to manufacturing capability. The scalars are linearly interpolated in between 2023 and 2035. However, a scalar of 1.0 is also used for 2025 to reflect near term limitations.<br><br>**45(q) Tax Credits for CCUS**<br>• A $CO_2$ storage tax credit of $60/metric tonne for EOR sites and $85/metric tonne for non EOR sites is provided to the CCS investments made in the 2030 and 2035 run years.<br><br>**Other**<br>• Nuclear endogenous retirements are disabled. Nuclear units are retired per a predetermined retirement schedule. Exceptions are made if a specific unit's age based on its license expiration date is greater than 60 years.<br>• Lower price steps are added to the 2045 and 2050 natural gas supply curves to reflect lower gas consumption.<br>• The $CO_2$ financing uncertainty adder is removed from fossil builds. |

Throughout the rest of this appendix, costs and emissions outcomes are provided for the Baseline and final rule with and without the IRA active to provide a comparison between compliance with the final rule under each baseline characterization.

### *4A.1.1 Compliance Cost Assessment for EGUs*

The estimates of incremental costs of supplying electricity for the final rule with and without IRA provisions are presented in Table 4A-2. Since the final rule generally does not result in significant, additional recordkeeping, monitoring or reporting requirements for EGUs, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are not included within the estimates in this table.

**Table 4A-2. National Power Sector Compliance Cost Estimates (millions of 2016$) for the Final Rule With and Without the IRA**

| | Final Rule + IRA | Final Rule |
|---|---|---|
| 2023-2027 (Annualized) | 13 | 14 |
| 2023-2045 (Annualized) | 196 | 449 |
| 2023 (Annual) | 47 | 57 |
| 2024 (Annual) | -17 | -5 |
| 2025 (Annual) | -17 | -5 |
| 2026 (Annual) | -17 | -5 |
| 2027 (Annual) | 67 | 24 |
| 2030 (Annual) | 577 | 705 |
| 2035 (Annual) | 297 | 817 |
| 2045 (Annual) | 163 | 182 |

"2023-2027 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2023 through 2027 and discounted using a 3.76 real discount rate.[119] This does not include compliance costs beyond 2027. "2023-2045 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2023 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. "2023 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those years.[120]

The impact of the IRA is to increase the economic competitiveness of lower emitting and renewable technologies relative to the higher emitting technologies that this rule seeks to regulate. Since the IRA incentives persist over the forecast period, we do not see the "rush to build" that characterizes modeling of incentives that will expire in the near future. As such the impact of the IRA is felt to a greater extent over the medium and longer term when the incentives are further aided by sector cost declines and performance improvements assumed over time. As a result, compliance costs are projected to be similar to the scenario without the IRA over the five-year period (2023-27) but are less than half the costs over the 2023-2045 period ($449 million 2016$ without the IRA and $196 million 2016$ including the IRA). Moreover, the costs peak in 2030 at $577 million 2016$ with the IRA as compared to peaking in 2035 at $817 million 2016$ under the no IRA scenario.

[119] This table reports compliance costs consistent with expected electricity sector economic conditions. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. The NPV of costs was then used to calculate the levelized annual value over a 5-year period (2023-2027) and a 20-year period (2023-2042) using the 3.76% rate as well.

[120] Cost estimates include financing charges on capital expenditures that would reflect a transfer and would not typically be considered part of total social costs.

*4A.1.2 Emissions Reduction Assessment for EGUs*

As indicated in Chapter 1, the $NO_X$ emissions reductions are presented in this RIA from 2023 through 2045 and are based on IPM projections. As outlined in Section 4.3.2 IPM is operating existing and newly installed controls seasonally based on historical operation patterns and seasonal and annual emission constraints within the model. Table 4A-3 presents the estimated reduction in power sector $NO_X$ emissions resulting from compliance with the final rule in the 22 states, as well as the impact on other states both with and without the IRA. The emission reductions follow an expected pattern: near term $NO_X$ emissions reductions are similar with and without the IRA in place, while longer-term reductions are lower in the presence of the IRA, reflecting a lower emitting baseline as a result of the greater levels of clean energy incentives modeled. Differences in emissions reductions after 2030 suggest that some units that are projected to retire in 2030 due to the final rule reported in Chapter 4 have already been retired due to the IRA by this point. Further, the EPA observes that the differences in estimated costs and emissions reductions in the IRA sensitivity suggests that there would also be differences in estimated health and climate benefits under this scenario, although the Agency did not have time under this rulemaking schedule to quantify those differences.

**Table 4A-3. EGU Ozone Season $NO_X$ Emissions and Emissions Changes (thousand tons) for the Baseline run and Final Rule with and without IRA from 2023 - 2045**

| Ozone Season $NO_X$ (thousand tons) | | Total Emissions | | | | Change from Baseline run | |
|---|---|---|---|---|---|---|---|
| | | Baseline run + IRA | Final Rule + IRA | Baseline run | Final Rule | With IRA | Without IRA |
| 2023 | 22 States | 229 | 220 | 230 | 220 | -10 | -10 |
| | Other States | 144 | 144 | 143 | 143 | 0 | 0 |
| | Nationwide | 373 | 363 | 373 | 363 | -10 | -10 |
| 2024 | 22 States | 201 | 182 | 203 | 181 | -20 | -22 |
| | Other States | 127 | 129 | 128 | 129 | 2 | 1 |
| | Nationwide | 329 | 311 | 331 | 310 | -18 | -21 |
| 2025 | 22 States | 173 | 144 | 176 | 143 | -30 | -34 |
| | Other States | 111 | 114 | 113 | 115 | 3 | 2 |
| | Nationwide | 284 | 258 | 289 | 258 | -26 | -32 |
| 2026 | 22 States | 158 | 135 | 167 | 140 | -23 | -27 |
| | Other States | 104 | 106 | 107 | 109 | 2 | 2 |
| | Nationwide | 262 | 241 | 274 | 248 | -20 | -25 |
| | 22 States | 142 | 126 | 157 | 137 | -16 | -20 |

| Ozone Season $NO_X$ (thousand tons) | | Total Emissions | | | | Change from Baseline run | |
|---|---|---|---|---|---|---|---|
| | | Baseline run + IRA | Final Rule + IRA | Baseline run | Final Rule | With IRA | Without IRA |
| 2027 | Other States | 97 | 98 | 101 | 103 | 2 | 2 |
| | Nationwide | 239 | 225 | 258 | 239 | -15 | -19 |
| 2028 | 22 States | 127 | 117 | 147 | 134 | -10 | -14 |
| | Other States | 90 | 90 | 95 | 96 | 1 | 2 |
| | Nationwide | 217 | 208 | 242 | 230 | -9 | -12 |
| 2030 | 22 States | 110 | 82 | 137 | 101 | -28 | -36 |
| | Other States | 84 | 85 | 91 | 93 | 0 | 2 |
| | Nationwide | 195 | 167 | 228 | 194 | -28 | -34 |
| 2035 | 22 States | 58 | 51 | 132 | 101 | -8 | -30 |
| | Other States | 50 | 50 | 88 | 89 | -1 | 1 |
| | Nationwide | 108 | 100 | 220 | 190 | -8 | -29 |
| 2040 | 22 States | 56 | 45 | 119 | 89 | -11 | -30 |
| | Other States | 38 | 38 | 79 | 79 | 0 | 0 |
| | Nationwide | 94 | 84 | 198 | 169 | -11 | -30 |
| 2045 | 22 States | 46 | 41 | 102 | 80 | -5 | -22 |
| | Other States | 36 | 36 | 76 | 76 | 0 | 0 |
| | Nationwide | 82 | 77 | 178 | 156 | -5 | -22 |

In addition to the ozone season $NO_X$ reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels (i.e., co-pollutants) that result from compliance strategies to reduce seasonal NOx emissions. These other emissions include the annual total changes in emissions of NOx, $SO_2$, $CO_2$, and direct $PM_{2.5}$ emissions changes. The emissions reductions are presented in Table 4A-4.

**Table 4A-4. EGU Annual Emissions and Emissions Changes for Annual $NO_X$, $SO_2$, $PM_{2.5}$, and $CO_2$ for the Baseline run and Final Rule with and without IRA from 2023 - 2045**

| Annual NOx (thousand tons) | | Total Emissions | | | | Change from Baseline run | |
|---|---|---|---|---|---|---|---|
| | | Baseline run + IRA | Final Rule + IRA | Baseline run | Final Rule | With IRA | Without IRA |
| 2023 | 22 States | 560 | 545 | 561 | 546 | -15 | -15 |
| | Other States | 329 | 329 | 328 | 329 | 0 | 0 |
| | Nationwide | 889 | 874 | 889 | 874 | -15 | -15 |
| 2024 | 22 States | 490 | 467 | 491 | 464 | -23 | -26 |
| | Other States | 284 | 286 | 286 | 287 | 2 | 1 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Nationwide | 774 | 753 | 777 | 752 | -21 | -25 |
| 2025 | 22 States | 419 | 388 | 420 | 383 | -31 | -38 |
| | Other States | 239 | 243 | 244 | 246 | 4 | 2 |
| | Nationwide | 659 | 631 | 664 | 629 | -27 | -35 |
| 2026 | 22 States | 381 | 357 | 398 | 367 | -24 | -31 |
| | Other States | 225 | 228 | 232 | 234 | 3 | 2 |
| | Nationwide | 606 | 585 | 630 | 601 | -21 | -29 |
| 2027 | 22 States | 342 | 326 | 375 | 351 | -17 | -24 |
| | Other States | 211 | 213 | 220 | 222 | 2 | 2 |
| | Nationwide | 553 | 539 | 595 | 573 | -15 | -22 |
| 2028 | 22 States | 304 | 295 | 353 | 336 | -9 | -17 |
| | Other States | 197 | 198 | 208 | 210 | 1 | 1 |
| | Nationwide | 500 | 492 | 561 | 545 | -8 | -16 |
| 2030 | 22 States | 261 | 199 | 324 | 261 | -63 | -64 |
| | Other States | 186 | 187 | 208 | 210 | 1 | 1 |
| | Nationwide | 447 | 386 | 533 | 471 | -62 | -62 |
| 2035 | 22 States | 131 | 110 | 304 | 254 | -21 | -49 |
| | Other States | 102 | 103 | 197 | 201 | 1 | 3 |
| | Nationwide | 233 | 213 | 501 | 455 | -20 | -46 |
| 2040 | 22 States | 100 | 87 | 267 | 221 | -13 | -46 |
| | Other States | 80 | 80 | 173 | 174 | 0 | 1 |
| | Nationwide | 180 | 167 | 440 | 395 | -13 | -45 |
| 2045 | 22 States | 82 | 79 | 218 | 195 | -4 | -23 |
| | Other States | 68 | 69 | 160 | 160 | 0 | 0 |
| | Nationwide | 151 | 148 | 378 | 355 | -3 | -23 |

| **Annual $SO_2$ (thousand tons)** | | **Total Emissions** | | | | **Change from Baseline run** | |
|---|---|---|---|---|---|---|---|
| | | **Baseline run + IRA** | **Final Rule + IRA** | **Baseline run** | **Final Rule** | **With IRA** | **Without IRA** |
| 2023 | 22 States | 908 | 912 | 916 | 915 | 4 | -1 |
| | Other States | 280 | 280 | 279 | 279 | 0 | 0 |
| | Nationwide | 1188 | 1192 | 1195 | 1194 | 4 | -1 |
| 2024 | 22 States | 778 | 765 | 787 | 766 | -13 | -21 |
| | Other States | 235 | 236 | 239 | 240 | 2 | 1 |
| | Nationwide | 1012 | 1001 | 1025 | 1006 | -11 | -19 |
| 2025 | 22 States | 647 | 618 | 657 | 617 | -29 | -40 |
| | Other States | 189 | 192 | 199 | 201 | 3 | 2 |
| | Nationwide | 837 | 810 | 856 | 818 | -26 | -38 |
| | 22 States | 540 | 520 | 574 | 543 | -20 | -31 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2026 | Other States | 169 | 172 | 181 | 183 | 2 | 2 |
| | Nationwide | 710 | 692 | 755 | 726 | -18 | -29 |
| | 22 States | 433 | 423 | 491 | 469 | -10 | -22 |
| 2027 | Other States | 150 | 151 | 163 | 164 | 1 | 1 |
| | Nationwide | 583 | 574 | 654 | 633 | -9 | -21 |
| | 22 States | 326 | 326 | 408 | 395 | -1 | -13 |
| 2028 | Other States | 130 | 130 | 145 | 145 | 0 | 0 |
| | Nationwide | 456 | 455 | 553 | 540 | -1 | -13 |
| | 22 States | 247 | 158 | 385 | 289 | -88 | -95 |
| 2030 | Other States | 126 | 128 | 147 | 150 | 2 | 2 |
| | Nationwide | 373 | 286 | 532 | 439 | -87 | -93 |
| | 22 States | 109 | 61 | 366 | 342 | -47 | -24 |
| 2035 | Other States | 49 | 50 | 135 | 138 | 1 | 3 |
| | Nationwide | 157 | 111 | 501 | 480 | -46 | -21 |
| | 22 States | 64 | 44 | 305 | 279 | -20 | -26 |
| 2040 | Other States | 34 | 34 | 126 | 127 | 0 | 1 |
| | Nationwide | 98 | 78 | 432 | 406 | -20 | -25 |
| | 22 States | 36 | 34 | 220 | 206 | -2 | -15 |
| 2045 | Other States | 22 | 22 | 128 | 128 | 0 | 0 |
| | Nationwide | 58 | 56 | 349 | 334 | -2 | -15 |

| **Annual $PM_{2.5}$ (thousand tons)** | | **Total Emissions** | | | | **Change from Baseline run** | |
|---|---|---|---|---|---|---|---|
| | | **Baseline run + IRA** | **Final Rule + IRA** | **Baseline run** | **Final Rule** | **With IRA** | **Without IRA** |
| | 22 States | 75 | 75 | 63 | 63 | 0 | 0 |
| 2023 | Other States | 47 | 47 | 40 | 40 | 0 | 0 |
| | Nationwide | 122 | 122 | 103 | 103 | 0 | 0 |
| | 22 States | 67 | 66 | 57 | 56 | -1 | -1 |
| 2024 | Other States | 42 | 42 | 36 | 36 | 0 | 0 |
| | Nationwide | 109 | 108 | 93 | 92 | -1 | -1 |
| | 22 States | 58 | 57 | 51 | 49 | -2 | -2 |
| 2025 | Other States | 37 | 37 | 33 | 33 | 0 | 0 |
| | Nationwide | 96 | 94 | 84 | 82 | -1 | -2 |
| | 22 States | 55 | 54 | 49 | 48 | -1 | -1 |
| 2026 | Other States | 36 | 36 | 33 | 33 | 0 | 0 |
| | Nationwide | 91 | 90 | 82 | 81 | -1 | -1 |
| | 22 States | 51 | 51 | 48 | 47 | 0 | -1 |
| 2027 | Other States | 35 | 35 | 32 | 32 | 0 | 0 |
| | Nationwide | 87 | 86 | 80 | 80 | 0 | -1 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2028 | 22 States | 48 | 48 | 47 | 46 | 0 | 0 |
| | Other States | 34 | 34 | 32 | 32 | 0 | 0 |
| | Nationwide | 82 | 82 | 79 | 78 | 0 | 0 |
| 2030 | 22 States | 45 | 39 | 45 | 43 | -6 | -2 |
| | Other States | 33 | 33 | 32 | 32 | 0 | 0 |
| | Nationwide | 78 | 72 | 76 | 75 | -5 | -1 |
| 2035 | 22 States | 30 | 28 | 46 | 44 | -2 | -2 |
| | Other States | 21 | 21 | 30 | 30 | 0 | 0 |
| | Nationwide | 51 | 49 | 75 | 74 | -2 | -1 |
| 2040 | 22 States | 26 | 25 | 44 | 43 | -1 | -2 |
| | Other States | 18 | 18 | 28 | 28 | 0 | 0 |
| | Nationwide | 44 | 43 | 73 | 71 | -1 | -2 |
| 2045 | 22 States | 23 | 23 | 42 | 42 | 0 | 0 |
| | Other States | 17 | 17 | 28 | 28 | 0 | 0 |
| | Nationwide | 40 | 40 | 70 | 70 | 0 | 0 |

| Annual $CO_2$ (million short tons) | | Total Emissions | | | | Change from Baseline run | |
|---|---|---|---|---|---|---|---|
| | | Baseline run + IRA | Final Rule + IRA | Baseline run | Final Rule | With IRA | Without IRA |
| 2023 | 22 States | 1030 | 1030 | 1033 | 1032 | 0 | 0 |
| | Other States | 592 | 592 | 591 | 592 | 0 | 0 |
| | Nationwide | 1622 | 1622 | 1624 | 1624 | 0 | 0 |
| 2024 | 22 States | 950 | 941 | 947 | 935 | -10 | -12 |
| | Other States | 538 | 540 | 539 | 541 | 3 | 2 |
| | Nationwide | 1488 | 1481 | 1487 | 1476 | -7 | -10 |
| 2025 | 22 States | 870 | 851 | 862 | 838 | -19 | -24 |
| | Other States | 483 | 488 | 488 | 491 | 5 | 3 |
| | Nationwide | 1354 | 1340 | 1350 | 1329 | -14 | -21 |
| 2026 | 22 States | 825 | 813 | 844 | 826 | -13 | -18 |
| | Other States | 467 | 471 | 477 | 480 | 4 | 3 |
| | Nationwide | 1292 | 1283 | 1322 | 1306 | -9 | -16 |
| 2027 | 22 States | 780 | 774 | 827 | 814 | -7 | -13 |
| | Other States | 450 | 454 | 467 | 469 | 3 | 2 |
| | Nationwide | 1231 | 1227 | 1294 | 1284 | -3 | -10 |
| 2028 | 22 States | 735 | 735 | 809 | 803 | -1 | -7 |
| | Other States | 434 | 436 | 457 | 459 | 3 | 2 |
| | Nationwide | 1169 | 1171 | 1266 | 1261 | 2 | -5 |
| 2030 | 22 States | 660 | 611 | 784 | 753 | -49 | -31 |
| | Other States | 390 | 397 | 450 | 455 | 7 | 5 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Nationwide | 1050 | 1008 | 1235 | 1209 | -42 | -26 |
| 2035 | 22 States | 416 | 397 | 792 | 774 | -19 | -19 |
| | Other States | 240 | 241 | 436 | 438 | 1 | 2 |
| | Nationwide | 656 | 638 | 1228 | 1212 | -18 | -16 |
| 2040 | 22 States | 352 | 342 | 727 | 706 | -11 | -21 |
| | Other States | 211 | 211 | 411 | 411 | 0 | 1 |
| | Nationwide | 563 | 553 | 1138 | 1117 | -10 | -20 |
| 2045 | 22 States | 330 | 327 | 670 | 662 | -3 | -9 |
| | Other States | 205 | 205 | 400 | 400 | 0 | 0 |
| | Nationwide | 535 | 532 | 1070 | 1061 | -3 | -9 |

### *4A.1.3 Impacts on Fuel Use and Generation Mix*

The Transport FIP for the 2015 ozone NAAQS is expected to result in significant $NO_X$ emissions reductions. It is also expected to have some impacts to the power sector. While these impacts are relatively small in percentage terms, consideration of these potential impacts is an important component of assessing the relative impact of the regulatory control alternatives. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2023, 2025 and 2030 IPM model run years with and without the IRA.

As outlined in Table 4A-5 coal consumption remains similar in 2023 between the two baselines. In 2025 and beyond, the baseline with IRA results in lower coal consumption, with the result that the reduction in total coal consumption is lower in the presence of the IRA than in its absence. However, reductions still occur, demonstrating that the policy constraints are binding.

**Table 4A-5. 2023, 2025 and 2030 Projected U.S. Power Sector Coal Use for the Baseline and the Final Rule with and without IRA**

| | | Million Tons | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|---|
| | Year | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Appalachia | 2023 | 121 | 121 | 121 | 121 | 0% | 0% |
| Interior | | 96 | 96 | 96 | 96 | 0% | 0% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% |
| West | | 381 | 381 | 382 | 382 | 0% | 0% |
| Total | | 602 | 602 | 603 | 603 | 0% | 0% |

| | | Million Tons | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|---|
| | Year | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Appalachia | 2025 | 75 | 74 | 80 | 79 | -2% | -2% |
| Interior | | 77 | 77 | 76 | 75 | 0% | -1% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% |
| West | | 255 | 244 | 257 | 244 | -4% | -5% |
| Total | | 411 | 399 | 417 | 402 | -3% | -4% |
| Appalachia | 2030 | 32 | 31 | 49 | 47 | -2% | -4% |
| Interior | | 46 | 35 | 51 | 49 | -24% | -3% |
| Waste Coal | | 4 | 4 | 4 | 4 | 0% | 0% |
| West | | 133 | 112 | 170 | 154 | -16% | -10% |
| Total | | 214 | 182 | 274 | 254 | -15% | -7% |

As outlined in Table 4A-6 gas consumption remains similar in 2023 between the two baselines. In 2025 gas consumption is elevated in the scenario with the IRA in place, reflecting greater levels of coal retirements and lower financing costs for new gas technology. In 2030, total gas consumption is lower in the IRA baseline since energy storage and renewables become more cost competitive relative to fossil fuels, and nuclear retirements are lower. The reduced coal dispatch due to the policy results in similar increases in gas consumption under both baselines.

**Table 4A-6. 2023, 2025 and 2030 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Final Rule with and without IRA**

| Trillion Cubic Feet | | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|
| Year | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| 2023 | 7.7 | 7.7 | 7.7 | 7.7 | 0% | 0% |
| 2025 | 9.6 | 9.8 | 9.2 | 9.4 | 2% | 2% |
| 2030 | 11.4 | 11.5 | 12.2 | 12.4 | 1% | 1% |

As outlined in Table 4A-7 and Table 4A-8 coal and gas prices remain similar in 2023 and 2025 between the two baselines. Gas prices reflect the current elevated fuel price environment through 2025, before returning to fundamentals by 2030. Coal prices reflect elevated levels in

2023, before returning to fundamentals by 2025. The result is that through 2025 the two baselines show similar price trends. By 2030, the gas prices in the IRA baseline are lower, since total gas consumption has fallen, reflecting decreased nuclear retirements, increasing renewable penetration, and falling coal dispatch. Increases in gas price as a result of the policy are similar between the two cases.

**Table 4A-7. 2023, 2025 and 2030 Projected Minemouth and Power Sector Delivered Coal Price (2016$) for the Baseline and the Final Rule with and without IRA**

| | | $/MMBtu | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|---|
| | | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Minemouth | 2023 | 1.6 | 1.6 | 1.6 | 1.6 | 0% | 0% |
| Delivered | 2023 | 2.2 | 2.2 | 2.2 | 2.2 | 0% | 0% |
| Minemouth | 2025 | 1.1 | 1.1 | 1.1 | 1.1 | 0% | 0% |
| Delivered | 2025 | 1.7 | 1.7 | 1.7 | 1.7 | -1% | -1% |
| Minemouth | 2030 | 1.1 | 1.1 | 1.1 | 1.2 | 2% | 1% |
| Delivered | 2030 | 1.4 | 1.4 | 1.6 | 1.6 | -1% | -2% |

**Table 4A-8. 2023, 2025 and 2030 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2016$) for the Baseline and the Final Rule with and without IRA**

| | | $/MMBtu | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|---|
| | | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Henry Hub | 2023 | 4.8 | 4.8 | 4.8 | 4.8 | 0% | 0% |
| Delivered | 2023 | 4.9 | 4.9 | 4.9 | 4.9 | 0% | 0% |
| Henry Hub | 2025 | 3.4 | 3.4 | 3.4 | 3.4 | 0% | 0% |
| Delivered | 2025 | 3.5 | 3.5 | 3.5 | 3.5 | 0% | 0% |
| Henry Hub | 2030 | 2.5 | 2.6 | 2.7 | 2.7 | 1% | 0% |
| Delivered | 2030 | 2.6 | 2.6 | 2.8 | 2.8 | 1% | 0% |

As outlined in Table 4A-9 the generation mix remains similar between the two baselines in 2023. By 2025, gas generation rises relative to coal generation, and increases in nuclear generation driven by reduced levels of nuclear retirement. Total non-hydro RE generation is lower, reflecting the fact that in the absence of the IRA the Production Tax Credit (PTC) for shore wind and the Investment Tax Credit (ITC) for solar PV builds are assumed to phase out through 2025. This results in a ‘rush to build’ in order to take advantage of the tax credits before they expire. Under the IRA scenario, the tax credits are both more valuable and extend throughout the forecast period, as such renewable additions accelerate over the forecast period, taking advantage of cost declines that occur later in the horizon. Hence gas generation peaks in 2025 and then declines over the rest of the forecast period under the IRA baseline, while gas generation grows throughout the forecast period under the non-IRA baseline.

Tightening mass budgets in the 2025 run year (representing the 2026 compliance year in the rule) lead to erosion of coal dispatch under the policy scenario under both cases. In 2030, imposition of the deferred backstop emission rate results in higher levels of coal retirement, driving coal generation lower under both scenarios.

**Table 4A-9. 2023, 2025 and 20230 Projected U.S. Generation by Fuel Type for the Baseline and the Final Rule with and without IRA**

| | | Generation (TWh) | | | | Percent Change from Baseline | |
|---|---|---|---|---|---|---|---|
| | Year | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Coal | 2023 | 1,131 | 1,131 | 1,133 | 1,133 | 0% | 0% |
| Natural Gas | | 1,091 | 1,091 | 1,090 | 1,090 | 0% | 0% |
| Nuclear | | 775 | 775 | 775 | 775 | 0% | 0% |
| Hydro | | 289 | 289 | 289 | 289 | 0% | 0% |
| Non-Hydro RE | | 757 | 757 | 756 | 756 | 0% | 0% |
| Oil/Gas Steam | | 27 | 27 | 27 | 27 | 0% | 0% |
| Other | | 33 | 33 | 33 | 33 | 0% | 0% |
| Grand Total | | 4,103 | 4,103 | 4,103 | 4,103 | 0% | 0% |
| Coal | 2025 | 777 | 755 | 793 | 765 | -3% | -4% |
| Natural Gas | | 1,376 | 1,397 | 1,311 | 1,332 | 1% | 2% |
| Nuclear | | 747 | 747 | 724 | 724 | 0% | 0% |
| Hydro | | 293 | 293 | 294 | 295 | 0% | 0% |
| Non-Hydro RE | | 910 | 912 | 995 | 1,002 | 0% | 1% |
| Oil/Gas Steam | | 18 | 18 | 18 | 18 | 0% | -1% |
| Other | | 32 | 32 | 32 | 32 | 0% | 0% |
| Grand Total | | 4,154 | 4,154 | 4,167 | 4,168 | 0% | 0% |
| Coal | 2030 | 397 | 347 | 523 | 489 | -13% | -7% |
| Natural Gas | | 1,635 | 1,653 | 1,691 | 1,710 | 1% | 1% |
| Nuclear | | 725 | 725 | 611 | 614 | 0% | 1% |
| Hydro | | 305 | 305 | 300 | 300 | 0% | 0% |
| Non-Hydro RE | | 1,192 | 1,224 | 1,111 | 1,122 | 3% | 1% |
| Oil/Gas Steam | | 12 | 11 | 22 | 22 | -6% | 0% |
| Other | | 32 | 31 | 32 | 32 | 0% | 0% |
| Grand Total | | 4,296 | 4,296 | 4,289 | 4,288 | 0% | 0% |

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind.

As outlined in Table 4A-10 the capacity mix follows similar trends to those seen under the generation mix table. Coal capacity in 2023 remains identical across cases, reflecting the limitation on retirements. In 2023 gas capacity is higher, reflecting incremental builds as a result of the removal of the carbon uncertainty adder. Non-Hydro RE builds are lower through 2025 under the IRA scenario and then higher thereafter, as described earlier. By 2030 total coal retirements as a result of the policy are 14 GW in the absence of IRA, and 17 GW in the presence of IRA. This is driven by the weaker competitive position of fossil fired EGUs under the IRA scenario, making SCR retrofits on existing coal plants less economic. As a result, there are 2.7 GW of SCR retrofits under the Final Rule with IRA scenario as compared to 8 GW of retrofits in the Final Rule scenario without IRA.

**Table 4A-10. 2023, 2025 and 2030 Projected U.S. Capacity by Fuel Type for the Baseline and the Final Rule with and without IRA**

| | | Capacity (GW) | | | | Percent Change from Baseline run | |
|---|---|---|---|---|---|---|---|
| | Year | Baseline Run + IRA | Final Rule + IRA | Baseline Run | Final Rule | With IRA | Without IRA |
| Coal | 2023 | 187 | 187 | 187 | 187 | 0% | 0% |
| Natural Gas | | 441 | 441 | 441 | 441 | 0% | 0% |
| Nuclear | | 97 | 97 | 97 | 97 | 0% | 0% |
| Hydro | | 102 | 102 | 102 | 102 | 0% | 0% |
| Non-Hydro RE | | 241 | 241 | 241 | 241 | 0% | 0% |
| Oil/Gas Steam | | 73 | 73 | 73 | 73 | 0% | 0% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% |
| Grand Total | | 1,163 | 1,163 | 1,163 | 1,163 | 0% | 0% |
| Coal | 2025 | 138 | 137 | 140 | 138 | 0% | -1% |
| Natural Gas | | 440 | 441 | 436 | 436 | 0% | 0% |
| Nuclear | | 93 | 93 | 91 | 91 | 0% | 0% |
| Hydro | | 102 | 102 | 102 | 102 | 0% | 0% |
| Non-Hydro RE | | 278 | 278 | 301 | 304 | 0% | 1% |
| Oil/Gas Steam | | 60 | 59 | 60 | 60 | 0% | 0% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% |
| Grand Total | | 1,136 | 1,136 | 1,154 | 1,155 | 0% | 0% |
| Coal | 2030 | 100 | 82 | 112 | 98 | -17% | -13% |
| Natural Gas | | 454 | 458 | 468 | 477 | 1% | 2% |
| Nuclear | | 91 | 91 | 76 | 76 | 0% | 1% |
| Hydro | | 104 | 104 | 103 | 103 | 0% | 0% |
| Non-Hydro RE | | 357 | 365 | 339 | 343 | 2% | 1% |
| Oil/Gas Steam | | 61 | 64 | 62 | 64 | 5% | 2% |
| Other | | 7 | 7 | 7 | 7 | 0% | 0% |
| Grand Total | | 1,203 | 1,204 | 1,189 | 1,189 | 0% | 0% |

Note: In this table, “Non-Hydro RE” includes biomass, geothermal, landfill gas, solar, and wind

## CHAPTER 5: BENEFITS

### Overview

The Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 Ozone NAAQS) is expected to reduce emissions of nitrogen oxides ($NO_X$) transported from states that contribute significantly to nonattainment or interfere with maintenance of the 2015 Ozone National Ambient Air Quality Standards (NAAQS) in downwind states. Implementing the Transport FIP for the 2015 Ozone NAAQS is expected to reduce emissions of $NO_X$, which will in turn reduce concentrations of ground-level ozone and fine particles ($PM_{2.5}$); the rule is also projected to reduce sulfur dioxide ($SO_2$), direct $PM_{2.5}$ emissions, carbon dioxide ($CO_2$) emissions as well as water effluents, and potentially reduce mercury (Hg) emissions. This chapter reports the estimated monetized health benefits from reducing concentrations of ozone and $PM_{2.5}$ for each of three regulatory control alternatives described in prior chapters.[121] The chapter also reports the estimated monetized climate benefits from reducing $CO_2$ emissions. Though the rule is likely to also yield positive benefits associated with reducing pollutants other than ozone and $PM_{2.5}$, limited time, resource and data limitations prevented us from characterizing the value of those reductions.

This chapter describes the methods used to estimate the benefits to human health of reducing concentrations of ozone from affected EGUs (electrical generating units) and non-EGUs (non-electric generating units, or other stationary source emissions sources) and $PM_{2.5}$ from affected EGUs. The analysis quantifies health benefits resulting from changes in ozone concentrations in 2023 and changes in ozone and $PM_{2.5}$ in 2026 for each of the three regulatory control alternatives (i.e., final rule, less stringent alternative, and more stringent alternative). The methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses are described in the Technical Support Document (TSD) for the 2022 PM NAAQS

[121] A comprehensive approach to benefit-cost analysis (BCA) is required to assess whether it is conceivable for those who experience a net gain from a regulatory action to potentially compensate those who experience a net loss. As such, a BCA should aim to evaluate all benefits and costs resulting from the regulation, which includes welfare effects from all changes in externalities due to changes in environmental contaminants as well as any other externalities. This requires evaluating changes in pollutant concentrations induced beyond the contaminant(s) targeted by the action.

Reconsideration Proposal RIA titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits*[122] (U.S. EPA 2023).

Analyses were also run for each year between 2023 and 2042, using the model surfaces as described below, but accounting for the change in population size in each year, income growth, and baseline mortality incidence rates at five-year increments. However, due to additional uncertainties associated with baseline air quality projections beyond 2026, annual health benefits beyond 2026 presented in Tables 5-7 and 5-8 are based on 2026 air quality changes. Additionally, within each 12 km grid cell we assumed the 2023 ozone concentration change until 2025 and the 2026 ozone and $PM_{2.5}$ concentration change until 2042. As we do not account fully for changes in the size or distribution of the population beyond the year 2026, and the changes in the level and location of $NO_X$ emissions attributable to this rule, this may introduce uncertainty to the analysis and is described below in Section 5.1.3.

Data, resource, and methodological limitations prevent the EPA from monetizing health benefits of reducing direct exposure to $NO_2$ and $SO_2$, ecosystem effects and visibility impairment associated with these pollutants, ozone and $PM_{2.5}$, as well as benefits from reductions in other pollutants, such as water effluents. We qualitatively discuss these unquantified benefits in this chapter.

## 5.1 Estimated Human Health Benefits

The final rule is expected to reduce ozone season and annual $NO_X$ emissions. In the presence of sunlight, $NO_X$ and volatile organic compounds (VOCs) can undergo a chemical reaction in the atmosphere to form ozone. Reducing $NO_X$ emissions generally reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. In addition to $NO_X$, the rule is also expected to reduce emissions of direct $PM_{2.5}$ and $SO_2$ throughout the year. Because $NO_X$ and $SO_2$ are also precursors to secondary formation of ambient $PM_{2.5}$, reducing

[122] The Agency recently asked the Science Advisory Board to evaluate the approach EPA takes to identifying, selecting and parametrizing endpoints to quantify and monetize health benefits; this approach is detailed in a Technical Support Document (TSD) noted above (U.S. EPA, 2023). Additional information regarding the composition of the SAB panel, the schedule for the review and the charge questions may be found at https://sab.epa.gov/ords/sab/f?p=114:18:11364624237840:::RP,18:P18_ID:2617

these emissions would reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-attributable health effects.

In this Transport FIP for the 2015 Ozone NAAQS regulatory impact analysis (RIA), as discussed above, the EPA quantifies benefits of changes in ozone and $PM_{2.5}$ concentrations. In particular, we incorporate evidence reported in the most recent completed PM and Ozone Integrated Science Assessments (ISAs) and account for recommendations from the Science Advisory Board (U.S. EPA 2019a, U.S. EPA 2020b, U.S. EPA-SAB 2019, U.S. EPA-SAB 2020a). When updating each health endpoint, the EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized below. Detailed descriptions of these updates are available in the TSD for the 2022 PM NAAQS Reconsideration Proposal RIA titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA 2023).

The *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD describes fully the Agency's approach for quantifying the number and value of estimated air pollution-related impacts. In this document the reader can find the rationale for selecting health endpoints to quantify; the demographic, health and economic data used; modeling assumptions; and our techniques for quantifying uncertainty.[123]

As structured, the rule would affect the distribution of ozone and $PM_{2.5}$ concentrations in much of the U.S.; this includes locations both meeting and exceeding the NAAQS for ozone and particulate matter (PM). This RIA estimates avoided ozone- and $PM_{2.5}$-related health impacts that are distinct from those reported in the RIAs for both ozone and PM NAAQS (U.S. EPA 2012, 2015e). The ozone and PM NAAQS RIAs illustrate, but do not predict, the benefits and costs of strategies that States may choose to enact when implementing a revised NAAQS; these

[123] The analysis was completed using BenMAP-CE version 1.5.8, which is a variant of the current publicly available version.

costs and benefits are illustrative and cannot be added to the costs and benefits of policies that prescribe specific emission control measures. This RIA estimates the benefits (and costs) of specific, estimated emissions control measures. As shown and described in Chapter 3, we project most levels of ozone and $PM_{2.5}$ to decrease, primarily in and downwind of the states included in this final rule.[124] The ozone and PM-related benefit estimates are based on these modeled changes in summer season average ozone concentrations and changes in average annual $PM_{2.5}$ concentrations.

### *5.1.1 Health Impact Assessment for Ozone and $PM_{2.5}$*

The benefits analysis presented in this chapter incorporates science-policy and technical changes that the Agency adopted and documented in the benefits chapter of the RIA accompanying the 2022 PM NAAQS Reconsideration Proposal (U.S. EPA 2022a), based on the 2019 PM ISA (U.S. EPA 2019a), Supplement to the 2019 PM ISA (U.S. EPA 2022b), and 2020 ozone ISA (U.S. EPA, 2020c).

Estimating the health benefits of reductions in ozone and $PM_{2.5}$ exposure begins with estimating the change in exposure for each individual and then estimating the change in each individual's risks for those health outcomes affected by exposure. The benefit of the reduction in each health risk is based on the exposed individual's willingness to pay (WTP) for the change in risk, assuming that each outcome is independent of one another. The greater the magnitude of the risk reduction from a given change in concentration, the greater the individual's WTP, all else equal. The social benefit of the change in health risks equals the sum of the individual WTP estimates across all of the affected individuals residing in the U.S.[125] We conduct this analysis by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as "benefits transfer." Below we describe the procedure we follow for: (1) selecting air pollution health endpoints to quantify; (2) calculating counts of air pollution effects using a health impact

[124] In a small number of areas in the northwest, we project ozone to increase slightly compared to the baseline.
[125] This RIA also reports the change in the sum of the risk, or the change in the total incidence, of a health outcome across the population. If the benefit per unit of risk is invariant across individuals, the total expected change in the incidence of the health outcome across the population can be multiplied by the benefit per unit of risk to estimate the social benefit of the total expected change in the incidence of the health outcome.

function; and (3) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature.

### *5.1.2 Selecting Air Pollution Health Endpoints to Quantify*

As a first step in quantifying ozone and $PM_{2.5}$-related human health impacts, the Agency consults the Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Ozone ISA) (U.S. EPA 2020b) and the Integrated Science Assessment and Supplement for Particulate Matter (PM ISA) (U.S. EPA 2019a, U.S. EPA 2022b). These three documents synthesize the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (i.e., hours or days-long) or chronic (i.e., years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship. The Agency estimates the incidence of air pollution effects for those health endpoints above where the ISA has classified them as either causal or likely-to-be-causal.

In brief, the ISA for ozone found short-term (less than one month) exposures to ozone to be causally related to respiratory effects, a “likely to be causal” relationship with metabolic effects and a “suggestive of, but not sufficient to infer, a causal relationship” for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (one month or longer) to ozone are “likely to be causal” for respiratory effects including respiratory mortality, and a “suggestive of, but not sufficient to infer, a causal relationship” for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality. The PM ISA found short-term exposure to $PM_{2.5}$ to be causally related to cardiovascular effects and mortality (i.e., premature death), respiratory effects as likely-to-be-causally related, and a suggestive relationship for metabolic effects and nervous system effects. The ISA identified cardiovascular effects and total mortality as being causally related to long-term exposure to $PM_{2.5}$. A likely-to-be-causal relationship was determined between long-term $PM_{2.5}$ exposures and respiratory effects, nervous system effects, and cancer effects; and the evidence was suggestive of a causal relationship for male and female reproduction and fertility effects, pregnancy and birth outcomes, and metabolic effects.

Table 5-1 reports the ozone and $PM_{2.5}$-related human health impacts effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive. And, among the effects quantified, it might not have been possible to quantify completely either the full range of human health impacts or economic values. Section 5.3 and Table 5-14 below report other omitted health and environmental benefits expected from the emissions and water effluent changes as a result of this rule, such as health effects associated with $NO_2$ and $SO_2$, and any welfare effects such as acidification and nutrient enrichment. Specifically, for ozone-related benefits, for EGUs and non-EGUs we conducted a full health benefits analysis that includes premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the years 2023 and 2026. For PM-related benefits for EGUs, we conducted a full health benefits analysis that includes premature deaths and illnesses attributable to photochemical modeled changes in average $PM_{2.5}$ concentrations for the year 2026.

Consistent with economic theory, the WTP for reductions in exposure to environmental hazards will depend on the expected impact of those reductions on human health and other outcomes. All else equal, WTP is expected to be higher when there is stronger evidence of a causal relationship between exposure to the contaminant and changes in a health outcome (McGartland et al., 2017). For example, in the case where there is no evidence of a potential relationship the WTP would be expected to be zero and the effect should be excluded from the analysis. Alternatively, when there is some evidence of a relationship between exposure and the health outcome, but that evidence is insufficient to definitively conclude that there is a causal relationship, individuals may have a positive WTP for a reduction in exposure to that hazard (U.S. EPA-SAB 2020b, Kivi and Shogren, 2010). Lastly, the WTP for reductions in exposure to pollutants with strong evidence of a relationship between exposure and effect are likely positive and larger than for endpoints where evidence is weak, all else equal. Unfortunately, the economic literature currently lacks a settled approach for accounting for how WTP may vary with uncertainty about causal relationships.

Given this challenge, the Agency draws its assessment of the strength of evidence on the relationship between exposure to $PM_{2.5}$ or ozone and potential health endpoints from the ISAs that are developed for the NAAQS process as discussed above. The focus on categories identified as having a "causal" or "likely to be causal" relationship with the pollutant of interest is to estimate the pollutant-attributable human health benefits in which we are most confident.[126] All else equal, this approach may underestimate the benefits of ozone and $PM_{2.5}$ exposure reductions as individuals may be WTP to avoid specific risks where the evidence is insufficient to conclude they are "likely to be caus[ed]" by exposure to these pollutants.[127] At the same time, WTP may be lower for those health outcomes for which causality has not been definitively established. This approach treats relationships with ISA causality determinations of "likely to be causal" as if they were known to be causal, and therefore benefits could be overestimated.

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[126] This decision criterion for selecting health effects to quantify and monetize ozone and $PM_{2.5}$ is only applicable to estimating the benefits of exposure of these two pollutants. This is also the approach used for identifying the unquantified benefit categories for criteria pollutants. This decision criterion may not be applicable or suitable for quantifying and monetizing health and ecological effects of other pollutants. The approach used to determine whether there is sufficient evidence of a relationship between an endpoint affected by non-criteria pollutants, and consequently a positive WTP for reductions in those pollutants, for other unquantified benefits described in this chapter can be found in the source documentation for each of these pollutants (see relevant sections below). The conceptual framework for estimating benefits when there is uncertainty in the causal relationship between a hazard and the endpoints it potentially affects described here applies to these other pollutants.
[127] The EPA includes risk estimates for an example health endpoint with a causality determination of "suggestive, but not sufficient to infer" that is associated with a potentially substantial economic value in the quantitative uncertainty characterization (*Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD section 6.2.3).

**Table 5-1. Health Effects of Ambient Ozone and $PM_{2.5}$**

| Category | Effect | Effect Quantified | Effect Monetized | More Information |
|---|---|---|---|---|
| Premature mortality from exposure to $PM_{2.5}$ | Adult premature mortality based on cohort study estimates and expert elicitation estimates (age 65-99 or age 30-99) | ✓ | ✓ | PM ISA |
| | Infant mortality (age <1) | ✓ | ✓ | PM ISA |
| Nonfatal morbidity from exposure to $PM_{2.5}$ | Heart attacks (age > 18) | ✓ | ✓[1] | PM ISA |
| | Hospital admissions—cardiovascular (ages 65-99) | ✓ | ✓ | PM ISA |
| | Emergency department visits— cardiovascular (age 0-99) | ✓ | ✓ | PM ISA |
| | Hospital admissions—respiratory (ages 0-18 and 65-99) | ✓ | ✓ | PM ISA |
| | Emergency room visits—respiratory (all ages) | ✓ | ✓ | PM ISA |
| | Cardiac arrest (ages 0-99; excludes initial hospital and/or emergency department visits) | ✓ | ✓[1] | PM ISA |
| | Stroke (ages 65-99) | ✓ | ✓[1] | PM ISA |
| | Asthma onset (ages 0-17) | ✓ | ✓ | PM ISA |
| | Asthma symptoms/exacerbation (6-17) | ✓ | ✓ | PM ISA |
| | Lung cancer (ages 30-99) | ✓ | ✓ | PM ISA |
| | Allergic rhinitis (hay fever) symptoms (ages 3-17) | ✓ | ✓ | PM ISA |
| | Lost work days (age 18-65) | ✓ | ✓ | PM ISA |
| | Minor restricted-activity days (age 18-65) | ✓ | ✓ | PM ISA |
| | Hospital admissions—Alzheimer's disease (ages 65-99) | ✓ | ✓ | PM ISA |
| | Hospital admissions—Parkinson's disease (ages 65-99) | ✓ | ✓ | PM ISA |
| | Other cardiovascular effects (e.g., other ages) | — | — | PM ISA[2] |
| | Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations) | — | — | PM ISA[2] |
| | Other nervous system effects (e.g., autism, cognitive decline, dementia) | — | — | PM ISA[2] |
| | Metabolic effects (e.g., diabetes) | — | — | PM ISA[2] |
| | Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.) | — | — | PM ISA[2] |
| | Cancer, mutagenicity, and genotoxicity effects | — | — | PM ISA[2] |
| Mortality from exposure to ozone | Premature respiratory mortality based on short-term study estimates (0-99) | ✓ | ✓ | Ozone ISA |
| | Premature respiratory mortality based on long-term study estimates (age 30–99) | ✓ | ✓ | Ozone ISA |
| Nonfatal morbidity from exposure to ozone | Hospital admissions—respiratory (ages 0-99) | ✓ | ✓ | Ozone ISA |
| | Emergency department visits—respiratory (ages 0-99) | ✓ | ✓ | Ozone ISA |
| | Asthma onset (0-17) | ✓ | ✓ | Ozone ISA |
| | Asthma symptoms/exacerbation (asthmatics age 2-17) | ✓ | ✓ | Ozone ISA |
| | Allergic rhinitis (hay fever) symptoms (ages 3-17) | ✓ | ✓ | Ozone ISA |
| | Minor restricted-activity days (age 18–65) | ✓ | ✓ | Ozone ISA |
| | School absence days (age 5–17) | ✓ | ✓ | Ozone ISA |
| | Decreased outdoor worker productivity (age 18–65) | — | — | Ozone ISA[2] |
| | Metabolic effects (e.g., diabetes) | — | — | Ozone ISA[2] |
| | Other respiratory effects (e.g., premature aging of lungs) | — | — | Ozone ISA[2] |

| | | | | |
|---|---|---|---|---|
| | Cardiovascular and nervous system effects | — | — | Ozone ISA[2] |
| | Reproductive and developmental effects | — | — | Ozone ISA[2] |

[1]Valuation estimate excludes initial hospital and/or emergency department visits.
[2] Not quantified due to data availability limitations and/or because current evidence is only suggestive of causality.

*5.1.1.2 Calculating Counts of Air Pollution Effects Using the Health Impact Function*

We use EPA's Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in summer season average ozone concentrations for the years 2023 and 2026 using health impact functions. The program is also used to estimate counts of premature deaths and illnesses attributable to photochemical modeled changes in annual average $PM_{2.5}$ concentrations from changes in $NO_x$, $SO_2$ and $PM_{2.5}$ emissions for the year 2026.

BenMAP quantifies counts of attributable effects using a health impact function, which combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and air pollution concentration to which the population is exposed.

The following provides an example of a health impact function, in this case for $PM_{2.5}$ mortality risk. We estimate counts of $PM_{2.5}$-related total deaths ($y_{ij}$) during each year i (i=1,…,I where I is the total number of years analyzed) among adults aged 30 and older (a) in each county in the contiguous U.S. j (j=1,…,J where J is the total number of counties) as

$$y_{ij} = \Sigma_a \, y_{ija}$$
$$y_{ija} = mo_{ija} \times (e^{\beta \cdot \Delta C_{ij}} - 1) \times P_{ija}, \quad \text{Eq[1]}$$

where $mo_{ija}$ is the baseline all-cause mortality rate for adults aged a=30-99 in county j in year i stratified in 10-year age groups, β is the risk coefficient for all-cause mortality for adults associated with annual average $PM_{2.5}$ exposure, $C_{ij}$ is the annual mean $PM_{2.5}$ concentration in county j in year i, and $P_{ija}$ is the number of county adult residents aged a=30-99 in county j in year i stratified into 5-year age groups.[128]

[128] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12 by 12 km grids. The BenMAP-CE tool assigns the rates of baseline death and disease stored at

The BenMAP-CE tool is pre-loaded with projected population from the Woods & Poole company; cause-specific and age-stratified death rates from the Centers for Disease Control and Prevention, projected to future years; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes from the Healthcare Cost and Utilization Program and other sources; concentration-response parameters from the published epidemiologic literature cited in the Integrated Science Assessments for fine particles and ground-level ozone; and, cost of illness or willingness to pay economic unit values for each endpoint. Changes in ozone and $PM_{2.5}$ concentrations are taken from the air pollution spatial surfaces for the analytic years 2023 (ozone only) and 2026 described in Chapter 3.

*5.1.1.3 Quantifying Cases of Ozone-Attributable Premature Death*

Mortality risk reductions account for the majority of monetized ozone-related and $PM_{2.5}$-related benefits. For this reason, this subsection and the following provide a brief background of the scientific assessments that underly the quantification of these mortality risks and identifies the risk studies used to quantify them in this RIA, for ozone and $PM_{2.5}$ respectively. As noted above, the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD describes fully the Agency's approach for quantifying the number and value of ozone and $PM_{2.5}$ air pollution-related impacts, including additional discussion of how the Agency selected the risk studies used to quantify them in this RIA. The TSD also includes additional discussion of the assessments that support quantification of these mortality risk than provide here.

In 2008, the National Academies of Science (NRC 2008) issued a series of recommendations to the EPA regarding the procedure for quantifying and valuing ozone-related mortality due to short-term exposures. Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multicity and [National Mortality and Morbidity Air Pollution Studies (NMMAPS)] …studies without exclusion of the meta-analyses" (NRC 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis of

the county level to the 12 by 12 km grid cells using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

total mortality (Bell et al. 2004), two multi-city studies of cardiopulmonary and total mortality (Huang et al. 2004; Schwartz 2005) and effect estimates from three meta-analyses of non-accidental mortality (Bell et al. 2005; Ito et al. 2005; Levy et al. 2005). Beginning with the 2015 Ozone NAAQS RIA, the Agency began quantifying ozone-attributable premature deaths using two newer multi-city studies of non-accidental mortality (Smith et al. 2009; Zanobetti and Schwartz 2008) and one long-term cohort study of respiratory mortality (Jerrett et al. 2009). The 2020 Ozone ISA included changes to the causality relationship determinations between short-term exposures and total mortality, as well as including more recent epidemiologic analyses of long-term exposure effects on respiratory mortality (U.E. EPA, 2020b). As a result, we use two estimates of ozone-attributable respiratory deaths from short-term exposures are estimated using the risk estimate parameters from Zanobetti et al. (2008) and Katsouyanni et al. (2009). Ozone-attributable respiratory deaths from long-term exposures are estimated using Turner et al. (2016). Due to time and resource limitations, we were unable to reflect the warm season defined by Zanobetti et al. (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of May-September.

*5.1.1.4 Quantifying Cases of $PM_{2.5}$-Attributable Premature Death*

When quantifying PM-attributable cases of adult mortality, we use the effect coefficients from two epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Turner et al. 2016) and the Medicare cohort (Di et al. 2017). The Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA 2019a) and Supplement to the 2019 PM ISA (U.S. EPA 2022b) concluded that the analyses of the ACS and Medicare cohorts provide strong evidence of an association between long-term $PM_{2.5}$ exposure and premature mortality with support from additional cohort studies. There are distinct attributes of both the ACS and Medicare cohort studies that make them well-suited to being used in a PM benefits assessment and so here we present $PM_{2.5}$ related effects derived using relative risk estimates from both cohorts.

The PM ISA, which was reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (SAB-CASAC) (EPA-SAB 2020a), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature supports the use of a no-threshold log-linear model to portray the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response relationship. The 2019 PM ISA, which informed the setting of the 2020 PM NAAQS, reviewed available studies that examined the potential for a population-level threshold to exist in the concentration-response relationship. Based on such studies, the ISA concluded that the evidence supports the use of a "no-threshold" model and that "little evidence was observed to suggest that a threshold exists" (U.S. EPA 2009) (pp. 2-25 to 2-26). Consistent with this evidence, the Agency historically has estimated health impacts above and below the prevailing NAAQS (U.S. EPA 2010c, 2010d, 2011c, 2011d, 2012, 2013b, 2014a, 2014b, 2014c, 2015a, 2015b, 2015c, 2015d, 2015e, 2016b).

### *5.1.2 Economic Valuation Methodology for Health Benefits*

We next quantify the economic value of the ozone and $PM_{2.5}$-related deaths and illnesses estimated above. Changes in ambient concentrations of air pollution generally yield small changes in the risk of future adverse health effects for a large number of people. The appropriate economic measure of the value of these small changes in risk of a health effect for the purposes of a benefit-cost analysis is WTP. For some health effects, such as hospital admissions, WTP estimates are not generally available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates are typically a lower bound estimate of the true value of reducing the risk of a health effect because they reflect the direct expenditures related to treatment, but not the value of avoided pain and suffering. The unit values applied in this analysis are provided in Table 21 of the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.

The value of avoided premature deaths generally account for over 95 percent of monetized ozone-related benefits and over 98 percent of monetized $PM_{2.5}$-related benefits. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB's Environmental Economics Advisory Committee (SAB-EEAC), the EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for changes in the risk of death (U.S. EPA-SAB 2000a). The VSL approach is a summary measure for the value of small changes in the risk of death experienced by a large number of people.

The EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, EPA applies the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA 2016a) while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $4.8 million (1990$). We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSL applied in this analysis in 2016$ after adjusting for income growth is $10.7 million for 2026.

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing changes in the risk of premature death and continues to engage with the SAB to identify scientifically sound approaches to update its mortality risk valuation estimates. In 2016, the Agency proposed new meta-analytic approaches for updating its estimates (U.S. EPA-SAB 2017), which were subsequently reviewed by the SAB-EEAC. The EPA is reviewing the SAB's formal recommendations.

In valuing $PM_{2.5}$-related premature mortality, we discount the value of premature mortality occurring in future years using rates of 3 percent and 7 percent (U.S. Office of Management and Budget 2003). We assume that there is a multi-year "cessation" lag between changes in PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, the EPA follows the advice of the SAB-HES to use a segmented lag structure that assumes 30 percent of premature deaths are reduced in the first year, 50 percent over years 2 to 5, and 20 percent over the years 6 to 20 after the reduction in $PM_{2.5}$ (U.S. EPA-SAB 2004). Changes in the cessation lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths.

Because estimated counts of short-term ozone-related premature mortality occur within each analysis year, these estimated ozone-related benefits are identical for all discount rates. When valuing changes in long-term ozone-attributable respiratory deaths using the Turner et al. (2015) study, we follow advice provided by the Health Effects Subcommittee of the SAB, which found that "…there is no evidence in the literature to support a different cessation lag between ozone and particulate matter. The HES therefore recommends using the same cessation lag structure and assumptions as for particulate matter when utilizing cohort mortality evidence for ozone" (U.S. EPA-SAB 2010).

These estimated health benefits do not account for the influence of future changes in the climate on ambient concentrations of pollutants (USGCRP 2016). For example, recent research suggests that future changes to climate may create conditions more conducive to forming ozone; the influence of changes in the climate on $PM_{2.5}$ concentrations are less clear (Fann et al. 2015). The estimated health benefits also do not consider the potential for climate-induced changes in temperature to modify the relationship between ozone and the risk of premature death (Fann et al. 2021, Jhun et al. 2014; Ren et al. 2008a, 2008b).

### *5.1.3 Characterizing Uncertainty in the Estimated Benefits*

This analysis includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emission inventories, projected emissions and emissions changes from the electricity planning model, projected baseline emission and emissions reductions from non-EGUs, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). When compounded, even small uncertainties can greatly influence the size of the total quantified benefits.

Our estimate of the total monetized ozone and $PM_{2.5}$-attributable benefits is based on the EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC 2002). Below are key assumptions underlying the estimates for ozone-related premature deaths, followed by key uncertainties associated with estimating the number and value of $PM_{2.5}$-related premature mortality.

The estimated number and value of avoided ozone-attributable deaths are subject to uncertainty. When estimating the economic value of avoided premature mortality from long-term exposure to ozone, we use a 20-year segment lag (as used for $PM_{2.5}$) as there is no alternative empirical estimate of the cessation lag for long-term exposure to ozone. The 20-year segmented lag accounts for the onset of cardiovascular related mortality, an outcome which is not relevant to the long-term respiratory mortality estimated here. We use a log-linear impact function without a threshold in modeling short-term ozone-related mortality. Thus, the estimates include health benefits from reducing ozone in areas with varied concentrations of ozone down to the lowest modeled concentrations. However, we acknowledge reduced confidence in specifying the shape of the concentration-response relationship in the range of ≤ 40ppb and below (2020 Ozone ISA, section 6.2.6).

We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, the PM ISA concluded that "many constituents of $PM_{2.5}$ can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes" (U.S. EPA 2009).

As noted above, we quantify health impacts of fine particles using a log-linear no-threshold model. Thus, some portion of the air quality and health benefits from the regulatory control alternatives will occur in areas not attaining the ozone or PM NAAQS. Expected changes in the ambient concentrations of both ozone and $PM_{2.5}$ pollutants may lead to states changing their NAAQS compliance approaches. However, we do not simulate how states would account for this rule when complying with the NAAQS, which introduces uncertainty in the estimated benefits (and costs).

Also, as noted above, we assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB 2004), which affects the valuation of mortality benefits at different discount rates. The above assumptions are subject to uncertainty.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. There are uncertainties inherent in identifying any particular point at which our confidence in reported associations decreases appreciably, and the scientific evidence provides no clear dividing line. This relationship between the air quality data and our confidence in the estimated risk is represented below in Figure 5-1.

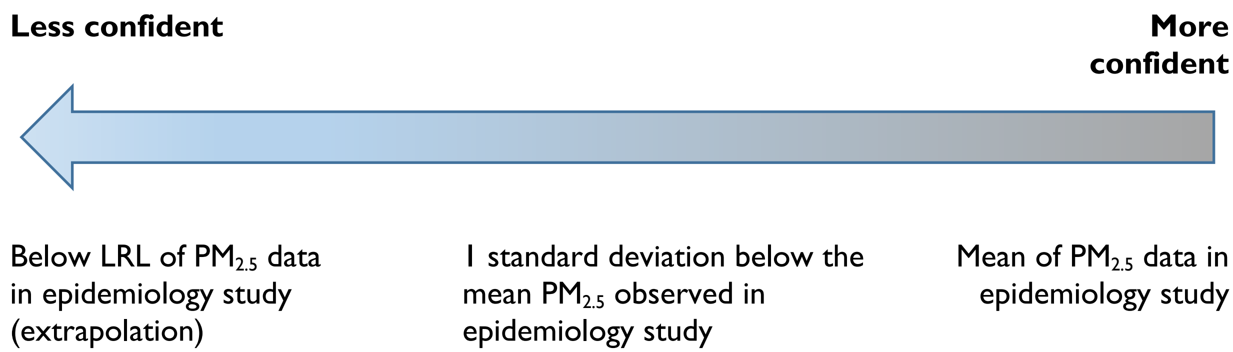


**Figure 5-1 Stylized Relationship between the $PM_{2.5}$ Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths**

For Turner et al. 2016, the LRL is 2.8 μg/m$^3$ and for Di et al. 2017, the LRL is 0.02 μg/m$^3$. Additional information on low concentration exposures in Turner et al. 2016 and Di et al. 2017 can be found in section 6.1.2.1 of the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD. These results are sensitive to the annual mean $PM_{2.5}$ concentration the air quality model predicted in each 12 km by 12 km grid cell. The air quality modeling predicts $PM_{2.5}$ concentrations to be at or below the current annual mean $PM_{2.5}$ NAAQS (12 μg/m$^3$) in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years. The results should be viewed in the context of the air quality modeling technique we used to estimate $PM_{2.5}$ concentrations. We are more confident in our ability to use the air quality modeling techniques described above to estimate *changes* in annual mean $PM_{2.5}$ concentrations than we are in our ability to estimate *absolute* $PM_{2.5}$ concentrations.

*5.1.4 Estimated Number and Economic Value of Health Benefits*

Below we report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95% confidence interval (Table 5-2, Table 5-3 and Table 5-4) for ozone-attributable health benefits in 2023 and 2026 and PM-attributable health benefits in 2026. The number of reduced estimated deaths and illnesses from the final rule and more and less stringent alternatives are calculated from the sum of individual reduced mortality and illness risks across the population. Table 5-5 and Table 5-6 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. We also report the stream of benefits from 2023 through 2042 for the final rule, more-, and less- stringent alternatives, using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts (Table 5-7 and Table 5-8.).[129]

[129] EPA continues to refine its approach for estimating and reporting PM-related effects at lower concentrations. The Agency acknowledges the additional uncertainty associated with effects estimated at these lower levels and seeks to develop quantitative approaches for reflecting this uncertainty in the estimated PM benefits.

**Table 5-2. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2023 (95% Confidence Interval) [a,b]**

| | | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|---|
| **Avoided premature respiratory mortalities** | | | | |
| Long-term exposure | Turner *et al*. (2016)[c] | 78<br>(54 to 100) | 80<br>(56 to 100) | 78<br>(54 to 100) |
| Short-term exposure | Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d] pooled | 3.5<br>(1.4 to 5.6) | 3.6<br>(1.5 to 5.7) | 3.5<br>(1.4 to 5.5) |
| **Morbidity effects** | | | | |
| Long-term exposure | Asthma onset[e] | 640<br>(550 to 720) | 650<br>(560 to 740) | 640<br>(550 to 720) |
| | Allergic rhinitis symptoms[g] | 3,600<br>(1,900 to 5,200) | 3,700<br>(1,900 to 5,400) | 3,600<br>(1,900 to 5,200) |
| Short-term exposure | Hospital admissions—respiratory[d] | 9.3<br>(-2.4 to 21) | 9.6<br>(-2.5 to 21) | 9.3<br>(-2.4 to 20) |
| | ED visits—respiratory[f] | 200<br>(54 to 410) | 200<br>(56 to 420) | 200<br>(54 to 410) |
| | Asthma symptoms | 110,000<br>(-14,000 to 240,000) | 120,000<br>(-14,000 to 240,000) | 110,000<br>(-14,000 to 240,000) |
| | Minor restricted-activity days[d,f] | 54,000<br>(22,000 to 85,000) | 55,000<br>(22,000 to 87,000) | 54,000<br>(21,000 to 85,000) |
| | School absence days | 41,000<br>(-5,800 to 86,000) | 42,000<br>(-5,900 to 88,000) | 41,000<br>(-5,700 to 85,000) |

[a] Values rounded to two significant figures.
[b] We estimated ozone benefits for changes in NOx for the ozone season for EGUs in 2023. This table does not include benefits from emissions reductions for non-EGUs because emissions reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.
[d] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).
[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.
[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.
[g] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

**Table 5-3. Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2026 (95% Confidence Interval) [a,b]**

| | | | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|---|---|
| **Exposure Duration** | **Study** | **Affected Facility** | **Avoided premature respiratory mortalities** | | |
| Long-term exposure | Turner *et al.* (2016)[c] | EGUs | 310 (220 to 400) | 560 (380 to 720) | 98 (68 to 130) |
| | | Non-EGUs | 580 (400 to 750) | 890 (620 to 1,200) | 220 (160 to 290) |
| | | EGUs + Non-EGUs | 890 (620 to 1,200) | 1,400 (1,000 to 1,900) | 320 (220 to 420) |
| Short-term exposure | Katsouyanni *et al.* (2009)[c,d] and Zanobetti *et al.* (2008)[d] pooled | EGUs | 14 (5.7 to 22) | 25 (10 to 40) | 4.4 (1.8 to 7.0) |
| | | Non-EGUs | 26 (11 to 41) | 40 (16 to 64) | 10 (4.1 to 16) |
| | | EGUs + Non-EGUs | 40 (16 to 64) | 66 (26 to 100) | 15 (5.9 to 23) |
| | **Morbidity effects** | | | | |
| Long-term exposure | Asthma onset[e] | EGUs | 2,300 (1,900 to 2,600) | 4,200 (3,600 to 4,700) | 730 (630 to 830) |
| | | Non-EGUs | 4,400 (3,800 to 5,000) | 6,900 (6,000 to 7,900) | 1,800 (1,500 to 2,000) |
| | | EGUs + Non-EGUs | 6,600 (5,700 to 7,500) | 11,000 (9,500 to 13,000) | 2,500 (2,100 to 2,800) |
| | Allergic rhinitis symptoms[g] | EGUs | 13,000 (6,800 to 19,000) | 24,000 (13,000 to 35,000) | 4,200 (2,200 to 6,100) |
| | | Non-EGUs | 25,000 (13,000 to 37,000) | 40,000 (21,000 to 58,000) | 10,000 (5,300 to 15,000) |
| | | EGUs + Non-EGUs | 38,000 (20,000 to 55,000) | 64,000 (34,000 to 92,000) | 14,000 (7,500 to 21,000) |
| Short-term exposure | Hospital admissions—respiratory[d] | EGUs | 38 (-9.9 to 84) | 67 (-17 to 150) | 12 (-3.1 to 26) |
| | | Non-EGUs | 70 (-18 to 160) | 110 (-28 to 240) | 27 (-7.0 to 60) |
| | | EGUs + Non-EGUs | 110 (-28 to 240) | 170 (-46 to 390) | 39 (-10 to 86) |
| | ED visits—respiratory[f] | EGUs | 720 (200 to 1,500) | 1,300 (370 to 2,800) | 240 (65 to 490) |
| | | Non-EGUs | 1,400 (390 to 3,000) | 2,200 (610 to 4,600) | 560 (150 to 1,200) |

| | | | | |
|---|---|---|---|---|
| | EGUs + Non-EGUs | 2,100 (590 to 4,500) | 3,600 (980 to 7,500) | 790 (220 to 1,700) |
| Asthma symptoms | EGUs | 420,000 (-51,000 to 870,000) | 770,000 (-95,000 to 1,600,000) | 130,000 (-17,000 to 280,000) |
| | Non-EGUs | 810,000 (-100,000 to 1,700,000) | 1,300,000 (-160,000 to 2,700,000) | 320,000 (-40,000 to 670,000) |
| | EGUs + Non-EGUs | 1,200,000 (-150,000 to 2,500,000) | 2,000,000 (-250,000 to 4,200,000) | 460,000 (-56,000 to 950,000) |
| Minor restricted-activity days[d,f] | EGUs | 190,000 (77,000 to 300,000) | 350,000 (140,000 to 560,000) | 62,000 (25,000 to 98,000) |
| | Non-EGUs | 380,000 (150,000 to 590,000) | 600,000 (240,000 to 940,000) | 150,000 (61,000 to 240,000) |
| | EGUs + Non-EGUs | 570,000 (230,000 to 900,000) | 950,000 (380,000 to 1,500,000) | 210,000 (85,000 to 340,000) |
| School absence days | EGUs | 150,000 (-21,000 to 310,000) | 270,000 (-38,000 to 570,000) | 48,000 (-6,700 to 100,000) |
| | Non-EGUs | 290,000 (-41,000 to 600,000) | 450,000 (-64,000 to 950,000) | 110,000 (-16,000 to 240,000) |
| | EGUs + Non-EGUs | 430,000 (-61,000 to 910,000) | 720,000 (-100,000 to 1,500,000) | 160,000 (-23,000 to 340,000) |

[a] Values rounded to two significant figures.
[b] We estimated ozone benefits for changes in NOx for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for EGUs in 2026.
[c] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.
[d] Converted ozone risk estimate metric from MDA1 to MDA8.
[e] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.
[f] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.
[g] Converted ozone risk estimate metric from DA24 to MDA8.

**Table 5-4. Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Final Rule and More and Less Stringent Alternatives for 2026 (95% Confidence Interval)**

| Avoided Mortality | Final Rule | More Stringent | Less Stringent |
|---|---|---|---|
| Pope III et al., 2019 (adult mortality ages 18-99 years) | 440<br>(320 to 570) | 1,400<br>(1,000 to 1,800) | 120<br>(84 to 150) |
| Wu et al., 2020 (adult mortality ages 65-99 years) | 200<br>(180 to 230) | 640<br>(570 to 720) | 53<br>(46 to 59) |
| Woodruff et al., 2008 (infant mortality) | 0.64<br>(-0.40 to 1.6) | 1.9<br>(-1.2 to 4.9) | 0.19<br>(-0.12 to 0.49) |
| **Avoided Morbidity** | **Final Rule** | **More Stringent** | **Less Stringent** |
| Hospital admissions—cardiovascular (age > 18) | 29<br>(21 to 36) | 92<br>(66 to 120) | 7.5<br>(5.4 to 9.5) |
| Hospital admissions—respiratory | 4.7<br>(0.18 to 9.0) | 15<br>(0.55 to 28) | 1.2<br>(0.047 to 2.4) |
| ED visits–cardiovascular | 64<br>(-25 to 150) | 200<br>(-78 to 470) | 17<br>(-6.7 to 41) |
| ED visits—respiratory | 130<br>(26 to 270) | 420<br>(82 to 870) | 37<br>(7.2 to 77) |
| Acute Myocardial Infarction | 6.8<br>(3.9 to 9.5) | 21<br>(12 to 30) | 1.7<br>(0.97 to 2.4) |
| Cardiac arrest | 3.1<br>(-1.3 to 7.1) | 10<br>(-4.1 to 23) | 0.84<br>(-0.34 to 1.9) |
| Hospital admissions–Alzheimer's Disease | 120<br>(92 to 150) | 340<br>(250 to 420) | 32<br>(24 to 40) |
| Hospital admissions–Parkinson's Disease | 13<br>(6.3 to 18) | 41<br>(21 to 60) | 3.2<br>(1.6 to 4.7) |
| Stroke | 12<br>(3.1 to 21) | 39<br>(10 to 66) | 3.2<br>(0.82 to 5.5) |
| Lung cancer | 14<br>(4.2 to 23) | 44<br>(13 to 74) | 3.6<br>(1.1 to 6.1) |
| Hay Fever/Rhinitis | 3,300<br>(790 to 5,700) | 10,000<br>(2,500 to 18,000) | 930<br>(220 to 1,600) |
| Asthma Onset | 520<br>(490 to 540) | 1,600<br>(1,600 to 1,700) | 150<br>(140 to 150) |
| Asthma symptoms – Albuterol use | 69,000<br>(-33,000 to 170,000) | 220,000<br>(-110,000 to 530,000) | 19,000<br>(-9,400 to 47,000) |
| Lost work days | 25,000<br>(21,000 to 28,000) | 79,000<br>(66,000 to 91,000) | 6,800<br>(5,700 to 7,800) |
| Minor restricted-activity days | 140,000<br>(120,000 to 170,000) | 460,000<br>(380,000 to 550,000) | 40,000<br>(32,000 to 47,000) |

**Table 5-5. Estimated Discounted Economic Value of Avoided Ozone-Related Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2023 (95% Confidence Interval; millions of 2016$)[a,b]**

| Disc. Rate | Pollutant | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|---|
| 3% | Ozone Benefits | $100 ($27 to $220)[c] *and* $820 ($91 to $2,100)[d] | $110 ($28 to $230)[c] *and* $840 ($94 to $2,200)[d] | $100 ($27 to $220)[c] *and* $810 ($91 to $2,100)[d] |
| 7% | Ozone Benefits | $93 ($17 to 210)[c] *and* $730 ($75 to $1,900)[d] | $96 ($18 to $210)[c] *and* $750 ($77 to $2,000)[d] | $93 ($17 to $210)[c] *and* $730 ($75 to $1,900)[d] |

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NOx for the ozone season. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

**Table 5-6. Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Final Rule and the Less and More Stringent Alternatives in 2026 (95% Confidence Interval; millions of 2016$)[a,b]**

| Disc Rate | Pollutant | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|---|
| 3% | Ozone Benefits | $1,100 ($280 to $2,400) *and* $9,400 ($1,000 to $25,000) | $1,900 (470 to $4,000) *and* $15,000 ($1,700 to $40,000) | $420 ($110 to $900) *and* $3,400 ($380 to $8,900) |
| | PM Benefits | $2,000 ($220 to $5,300) *and* $4,400 ($430 to $12,000) | $6,400 ($690 to $17,000) *and* $14,000 ($1,300 to $37,000) | $530 ($57 to $1,400) *and* $1,100 ($110 to $3,100) |
| | Ozone plus PM Benefits | $3,200 ($500 to $7,700)[c] *and* $14,000 ($1,500 to $36,000)[d] | $8,300 ($1,200 to $21,000)[c] *and* $29,000 ($3,000 to $77,000)[d] | $950 ($160 to $2,300)[c] *and* $4,600 ($490 to $12,000)[d] |
| 7% | Ozone Benefits | $1,000 ($180 to $2,300) *and* $8,400 ($850 to $22,000) | $1,700 ($300 to $3,800) *and* $14,000 ($1,400 to $36,000) | $380 ($68 to $850) *and* $3,100 ($310 to $8,100) |
| | PM Benefits | $1,800 ($190 to $4,700) *and* $3,900 ($380 to $11,000) | $5,800 ($600 to $15,000) *and* $12,000 ($1,200 to $33,000) | 470 ($50 to $1,200) *and* $1,000 ($100 to $2,800) |
| | Ozone plus PM Benefits | $2,800 ($370 to $7,000)[c] *and* $12,000 ($1,200 to $33,000)[d] | $7,500 ($910 to $19,000)[c] *and* $26,000 ($2,600 to $69,000)[d] | $850 ($120 to $2,100)[c] *and* $4,100 ($410 to $11,000)[d] |

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NOx for the ozone season and annual changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Wu et al. (2020) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2016) long-term $PM_{2.5}$ exposure mortality risk estimate.

**Table 5-7. Stream of Human Health Benefits from 2023 through 2042: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality for EGUs and Non-EGUs and Long-Term $PM_{2.5}$ Mortality for EGUs (Discounted at 3%; millions of 2016$)[a]**

| | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|
| 2023* | 820 | 840 | 810 |
| 2024 | 810 | 840 | 810 |
| 2025 | 8,600 | 14,000 | 3,100 |
| 2026* | 13,000 | 27,000 | 4,200 |
| 2027 | 13,000 | 26,000 | 4,200 |
| 2028 | 12,000 | 25,000 | 4,000 |
| 2029 | 12,000 | 25,000 | 4,000 |
| 2030 | 12,000 | 25,000 | 4,000 |
| 2031 | 12,000 | 25,000 | 3,900 |
| 2032 | 12,000 | 25,000 | 3,900 |
| 2033 | 11,000 | 24,000 | 3,800 |
| 2034 | 11,000 | 24,000 | 3,800 |
| 2035 | 11,000 | 24,000 | 3,700 |
| 2036 | 11,000 | 24,000 | 3,700 |
| 2037 | 11,000 | 23,000 | 3,700 |
| 2038 | 11,000 | 23,000 | 3,600 |
| 2039 | 10,000 | 22,000 | 3,500 |
| 2040 | 10,000 | 22,000 | 3,500 |
| 2041 | 10,000 | 22,000 | 3,400 |
| 2042 | 10,000 | 21,000 | 3,400 |
| ***Net Present Value*** | **200,000** | **420,000** | **69,000** |

*Year in which air quality models were run. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Pope et al. 2016 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2017 study); and ozone and $PM_{2.5}$-related morbidity effects.

[a] For the years 2023-2025, there are no non-EGU emissions reductions. As such, there are no estimated benefits from non-EGU reductions for 2023-2025.

**Table 5-8. Stream of Human Health Benefits from 2023 through 2042: Monetized Benefits Quantified as Sum of Short-Term Ozone Mortality for EGUs and Non-EGUs and Long-Term $PM_{2.5}$ Mortality for EGUs (Discounted at 7%; millions of 2016$)[a]**

| | Final Rule | More Stringent Alternative | Less Stringent Alternative |
|---|---|---|---|
| 2023* | 730 | 750 | 730 |
| 2024 | 700 | 720 | 700 |
| 2025 | 7,100 | 12,000 | 2,600 |
| 2026* | 10,000 | 21,000 | 3,300 |
| 2027 | 9,700 | 20,000 | 3,200 |
| 2028 | 8,900 | 19,000 | 2,900 |
| 2029 | 8,500 | 18,000 | 2,800 |
| 2030 | 8,200 | 17,000 | 2,700 |
| 2031 | 7,800 | 17,000 | 2,600 |
| 2032 | 7,500 | 16,000 | 2,500 |
| 2033 | 7,000 | 15,000 | 2,300 |
| 2034 | 6,700 | 14,000 | 2,200 |
| 2035 | 6,400 | 14,000 | 2,100 |
| 2036 | 6,100 | 13,000 | 2,000 |
| 2037 | 5,800 | 12,000 | 1,900 |
| 2038 | 5,400 | 11,000 | 1,800 |
| 2039 | 5,100 | 11,000 | 1,700 |
| 2040 | 4,900 | 10,000 | 1,600 |
| 2041 | 4,600 | 9,800 | 1,500 |
| 2042 | 4,400 | 9,300 | 1,500 |
| **Net Present Value** | **130,000** | **260,000** | **43,000** |

*Year in which air quality models were run. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Pope et al. 2016 study); Ozone-attributable deaths (quantified using a pooled estimate of results quantified using concentration-response relationships two short-term exposure mortality studies); and ozone and $PM_{2.5}$-related morbidity effects.

[a] For the years 2023-2025, there are no non-EGU emissions reductions. As such, there are no estimated benefits from non-EGU reductions for 2023-2025.

## 5.2 Climate Benefits from Reducing $CO_2$

We estimate the climate benefits for this final rulemaking using estimates of the social cost of greenhouse gases (SC-GHG), specifically the social cost of carbon (SC-$CO_2$). The SC-$CO_2$ is the monetary value of the net harm to society associated with a marginal increase in $CO_2$ emissions in a given year, or the benefit of avoiding that increase. In principle, SC-$CO_2$ includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-$CO_2$, therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect $CO_2$ emissions. In practice, data and modeling limitations naturally restrain the ability of SC-$CO_2$ estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. The EPA and other Federal agencies began regularly incorporating SC- $CO_2$ estimates in their benefit-cost analyses conducted under Executive Order (E.O.) 12866[130] since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing $CO_2$ emissions in that rulemaking process.

In 2017, the National Academies of Sciences, Engineering, and Medicine published a report that provides a roadmap for how to update SC-GHG estimates used in Federal analyses going forward to ensure that they reflect advances in the scientific literature (National Academies 2017). The National Academies' report recommended specific criteria for future SC-GHG updates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process. The research community has made considerable progress in developing new data and methods that help to advance various components of the SC-GHG estimation process in response to the National Academies' recommendations.

In a first-day executive order (E.O. 13990), Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis, President Biden called for a renewed focus on updating estimates of the social cost of greenhouse gases (SC-GHG) to reflect the latest science, noting that "it is essential that agencies capture the full benefits of reducing

[130] Presidents since the 1970s have issued executive orders requiring agencies to conduct analysis of the economic consequences of regulations as part of the rulemaking development process. E.O. 12866, released in 1993 and still in effect today, requires that for all economically significant regulatory actions, an agency provide an assessment of the potential costs and benefits of the regulatory action, and that this assessment include a quantification of benefits and costs to the extent feasible. Many statutes also require agencies to conduct at least some of the same analyses required under E.O. 12866, such as the Energy Policy and Conservation Act, which mandates the setting of fuel economy regulations. For purposes of this action, monetized climate benefits are presented for purposes of providing a complete benefit-cost analysis under E.O. 12866 and other relevant executive orders. The estimates of change in GHG emissions and the monetized benefits associated with those changes play no part in the record basis for this action, which is taken to implement the good neighbor provision, CAA section 110(a)(2)(D)(i)(I), for the 2015 ozone NAAQS.

greenhouse gas emissions as accurately as possible." Important steps have been taken to begin to fulfill this directive of E.O. 13990. In February 2021, the Interagency Working Group on the SC-GHG (IWG) released a technical support document (hereinafter the "February 2021 TSD") that provided a set of IWG recommended SC-GHG estimates while work on a more comprehensive update is underway to reflect recent scientific advances relevant to SC-GHG estimation (IWG 2021). In addition, as discussed further below, EPA has developed a draft updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process.[131]

The EPA has applied the IWG's recommended interim SC-GHG estimates in the Agency's regulatory benefit-cost analyses published since the release of the February 2021 TSD and is likewise using them in this RIA. We have evaluated the SC-GHG estimates in the February 2021 TSD and have determined that these estimates are appropriate for use in estimating the social benefits of GHG reductions expected to occur as a result of the final rule and alternative standards. These SC-GHG estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. After considering the TSD, and the issues and studies discussed therein, the EPA concludes that these estimates, while likely an underestimate, are the best currently available SC-GHG estimates until revised estimates have been developed reflecting the latest, peer-reviewed science.

The SC-GHG estimates presented in the February 2021 SC-GHG TSD and used in this RIA were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to develop estimates relying on the best available science for agencies to use. The IWG published SC-$CO_2$ estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs

[131] See https://www.epa.gov/environmental-economics/scghg

were run using a common set of input assumptions in each model for future population, economic, and $CO_2$ emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric $CO_2$ concentrations. These estimates were updated in 2013 based on new versions of each IAM.[132] In August 2016 the IWG published estimates of the social cost of methane (SC-$CH_4$) and nitrous oxide (SC-$N_2O$) using methodologies that are consistent with the methodology underlying the SC-$CO_2$ estimates. The modeling approach that extends the IWG SC-$CO_2$ methodology to non-$CO_2$ GHGs has undergone multiple stages of peer review. The SC-$CH_4$ and SC-$N_2O$ estimates were developed by Marten, Kopits, Griffiths, Newbold, and Wolverton (2015) and underwent a standard double-blind peer review process prior to journal publication. These estimates were applied in regulatory impact analyses of EPA proposed rulemakings with $CH_4$ and $N_2O$ emissions impacts.[133] The EPA also sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates, the EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015 (EPA 2015f, 2015g). The EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.[134] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-$CO_2$ estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-$CO_2$ estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* and recommended specific criteria for future updates to the SC-$CO_2$ estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies

[132] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).
[133] The SC-CH4 and SC-N2O estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2 (U.S. EPA, 2015).
[134] See IWG (2016b) for more discussion of the SC-CH4 and SC-N2O and the peer review and public comment processes accompanying their development.

2017). Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-GHG estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5). Benefit-cost analyses following E.O. 13783 used SC-$CO_2$ estimates that attempted to focus on the specific share of climate change damages in the U.S. as captured by the models (which did not reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two default discount rates recommended by Circular A-4, 3 percent and 7 percent.[135] All other methodological decisions and model versions used in SC-$CO_2$ calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established an IWG and directed it to develop an update of the SC-$CO_2$ estimates that reflect the best available science and the recommendations of the National Academies. In February 2021, the IWG recommended the interim use of the most recent SC- $CO_2$ estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation (IWG, 2021). As discussed in the February 2021 TSD, the IWG's selection of these interim estimates reflected the immediate need to have SC- $CO_2$ estimates available for agencies to use in regulatory benefit-cost analyses and other applications that were developed using a transparent process, peer reviewed methodologies, and the science available at the time of that process.

As noted above, the EPA participated in the IWG but has also independently evaluated the interim SC-$CO_2$ estimates published in the February 2021 TSD and determined they are appropriate to use to estimate climate benefits for this action. The EPA and other agencies intend to undertake a fuller update of the SC- $CO_2$ estimates that takes into consideration the advice of the National Academies (2017) and other recent scientific literature. The EPA has also evaluated

[135] The EPA regulatory analyses under E.O. 13783 included sensitivity analyses based on global SC-GHG values and using a lower discount rate of 2.5%. OMB Circular A-4 (OMB, 2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG's 2015 Response to Comments, OMB—as a co-chair of the IWG—made clear that "Circular A-4 is a living document," that "the use of 7 percent is not considered appropriate for intergenerational discounting," and that "[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." OMB, as part of the IWG, similarly repeatedly confirmed that "a focus on global SCC estimates in [regulatory impact analyses] is appropriate" (IWG 2015).

the supporting rationale of the February 2021 TSD, including the studies and methodological issues discussed therein, and concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG found that the SC-$CO_2$ estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages.

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees with this assessment and, therefore, in this RIA, the EPA centers attention on a global measure of SC-$CO_2$. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. A robust estimate of climate damages only to U.S. citizens and residents that accounts for the myriad of ways that global climate change reduces the net welfare of U.S. populations does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. The EPA, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts.

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-$CO_2$. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context (IWG, 2010; IWG, 2013; IWG, 2016a; IWG, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[136] Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. The EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. The EPA also notes that while OMB Circular A-4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and consumption benefits…at a lower rate than for intragenerational analysis." In the 2015 Response

[136] GHG emissions are stock pollutants, where damages are associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, EPA, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, the EPA concludes that a 7 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this RIA. In this analysis, to calculate the present and annualized values of climate benefits, the EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends "to ensure internal consistency—i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95$^{th}$ percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.[137]

Table 5-9 summarizes the interim SC-$CO_2$ estimates for the years 2020 to 2050. These estimates are reported in 2016 dollars but are otherwise identical to those presented in the IWG's 2016 TSD (IWG 2016b). For purposes of capturing uncertainty around the SC-$CO_2$ estimates in analyses, the 2021 TSD emphasizes the importance of considering all four of the SC-$CO_2$ values. The SC-$CO_2$ increases over time within the models – i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

[137] At the time of proposal of this rule, a preliminary injunction was in place that prevented the Agency from displaying the February 2021 TSD-based Interim Estimates. That injunction was subsequently stayed on appeal. The Agency then prepared an addendum to the RIA for the proposed rule presenting the monetized climate benefits of the proposed rule and placed this in the docket and on our website. The EPA invited comment on that analysis. As that document explained, and as remains true for this final rule, "the monetized climate benefits . . . are not a part of the technical or legal basis of the proposed action for which the RIA was prepared." *See* Addendum to the Regulatory Impact Analysis: Monetizing Climate Benefits for the Proposed FIP for Addressing Regional Ozone Transport for the 2015 Ozone NAAQS, available at https://www.epa.gov/system/files/documents/2022-04/2015-fip-climate-benefits-technical-memo_04052022.pdf.

**Table 5-9. Interim Social Cost of Carbon Values, 2020-2050 (2016$/Metric Tonne $CO_2$)**

| Emissions Year | Discount Rate and Statistic | | | |
|---|---|---|---|---|
| | 5% Average | 3% Average | 2.5% Average | 3% 95th Percentile |
| 2020 | $13 | $47 | $71 | $140 |
| 2025 | $15 | $52 | $77 | $160 |
| 2030 | $18 | $57 | $83 | $170 |
| 2035 | $20 | $63 | $90 | $190 |
| 2040 | $23 | $67 | $95 | $210 |
| 2045 | $26 | $73 | $100 | $220 |
| 2050 | $29 | $78 | $110 | $240 |

Note: These SC-$CO_2$ values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2016 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). The values are stated in $/metric tonne $CO_2$ (1 metric tonne equals 1.102 short tons) and vary depending on the year of $CO_2$ emissions. This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this RIA are available on OMB's website: https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs.
*Source: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021)*

There are a number of limitations and uncertainties associated with the SC-$CO_2$ estimates presented in Table 5-9. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 5-2 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-$CO_2$ estimates for emissions in 2030. The distributions of SC-$CO_2$ estimates reflect uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-$CO_2$ estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-$CO_2$. This is because $CO_2$ emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the 2021 TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

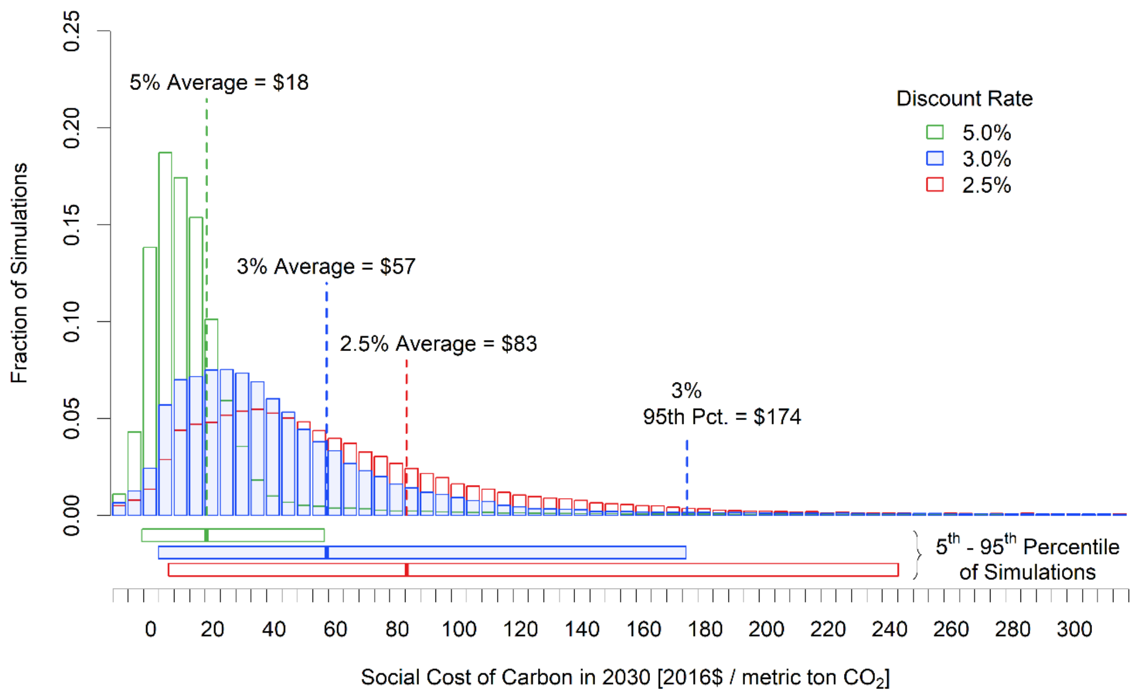


**Figure 5-2. Frequency Distribution of SC-CO2 Estimates for 2030**[138]

The interim SC-CO2 estimates presented in Table 5-8 have a number of limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" – i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages – lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the

[138] Although the distributions and numbers in Figure 5-2 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.78 percent of the estimates falling below the lowest bin displayed and 3.64 percent of the estimates falling above the highest bin displayed.

socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-$CO_2$ estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-$CO_2$ estimates used in this RIA likely underestimate the damages from $CO_2$ emissions. EPA concurs that the values used in this RIA conservatively underestimate the rule's climate benefits. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (IPCC 2007), which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-$CO_2$ estimates "very likely…underestimate the damage costs" due to omitted impacts. Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report and other recent scientific assessments (IPCC 2014) (e.g., IPCC 2018, 2019a, 2019b; U.S. Global Change Research Program (USGCRP) 2016, 2018; and National Academies 2016, 2019). These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time (IPCC 2007). A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP 2018). EPA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates and concurs with the February 2021 SC-GHG TSD's assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions.

The February 2021 TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates. The IWG is currently working on a comprehensive update of the SC-GHG estimates taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 TSD and other input from experts and diverse stakeholder groups (National Academies 2017). While that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, the EPA presented a draft set of updated SC-GHG estimates within a sensitivity analysis in the regulatory impact analysis of the EPA's November 2022 supplemental proposal for oil and gas standards that that aims to incorporate recent advances in the climate science and economics literature. Specifically, the draft updated methodology incorporates new literature and research consistent with the National Academies near-term recommendations on socioeconomic and emissions inputs, climate modeling components, discounting approaches, and treatment of uncertainty, and an enhanced representation of how physical impacts of climate change translate to economic damages in the modeling framework based on the best and readily adaptable damage functions available in the peer reviewed literature. The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the docket for the proposed Oil and Gas rule. The EPA is also embarking on an external peer review of this technical report. More information about this process and public comment opportunities is available on the EPA's website.[139] EPA's draft technical report will be among the many technical inputs available to the IWG as it continues its work.

Table 5-10 shows the estimated monetary value of the estimated changes in $CO_2$ emissions expected to occur over 2021-2040 for this rule, the more-stringent alternative, and the less-stringent alternative. The EPA estimated the dollar value of the $CO_2$-related effects for each analysis year between 2021 and 2040 by applying the SC-$CO_2$ estimates, shown in Table 5-9, to the estimated changes in $CO_2$ emissions in the corresponding year under the regulatory options. The EPA then calculated the present value and annualized benefits from the perspective of 2020 by discounting each year-specific value to the year 2020 using the same discount rate used to calculate the SC-$CO_2$.[140]

[139] See https://www.epa.gov/environmental-economics/scghg

[140] According to OMB's Circular A-4 (OMB 2003), an "analysis should focus on benefits and costs that accrue to citizens and residents of the United States", and international effects should be reported, but separately. Circular A-4 also reminds analysts that "[d]ifferent regulations may call for different emphases in the analysis, depending on the

**Table 5-10. Estimated Climate Benefits from Changes in CO2 Emissions 2023 - 2040 (Millions of 2016$)[a]**

| | | Discount Rate and Statistic | | | |
|---|---|---|---|---|---|
| **Regulatory Alternative** | **Year** | **5% Average** | **3% Average** | **2.5% Average** | **3% 95th Percentile** |
| **Final Rule** | 2023 | 1 | 5 | 7 | 14 |
| | 2024 | 319 | 1,075 | 1,586 | 3,218 |
| | 2025 | 329 | 1,096 | 1,611 | 3,286 |
| | 2026 | 338 | 1,117 | 1,637 | 3,354 |
| | 2030 | 474 | 1,512 | 2,191 | 4,572 |
| | 2035 | 335 | 1,015 | 1,448 | 3,095 |
| | 2040 | 474 | 1,378 | 1,941 | 4,234 |
| **More-Stringent Alternative** | 2023 | 1 | 5 | 7 | 14 |
| | 2024 | 605 | 2,040 | 3,009 | 6,104 |
| | 2025 | 623 | 2,079 | 3,057 | 6,234 |
| | 2026 | 642 | 2,119 | 3,105 | 6,363 |

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nature and complexity of the regulatory issues." To correctly assess the total climate damages to U.S. citizens and residents, an analysis should account for all the ways climate impacts affect the welfare of U.S. citizens and residents, including how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC-GHG estimates used in regulatory analysis under revoked EO 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions. These estimates range from $8 per metric ton CO2 (2016 dollars) using a 3 percent discount rate for emissions occurring in 2023 to $9 per metric ton CO2 using a 3 percent discount rate for emissions occurring in 2040. Applying the same estimate (based on a 3% discount rate) to the $CO_2$ emissions reduction expected under the finalized option in this final rule would yield benefits from climate impacts within U.S borders of $0.8 million in 2023, increasing to $138 million in 2035. However, as discussed at length in the IWG's February 2021 SC-GHG TSD, these estimates are an underestimate of the benefits of GHG mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, as discussed in this analysis, EPA concurs with the assessment in the February 2021 SC-GHG TSD that the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC-GHG estimates developed under E.O. 13783, the models "were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages" p.29 (U.S. GAO 2020). Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were "limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions" p.26 (U.S. GAO 2020). It is also important to note that the SC-GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been "soundly rejected by economists as improper and unsupported by science," and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates "fail[ed] to consider…important aspect[s] of the problem" and departed from the "best science available" as reflected in the global estimates. *California v. Bernhardt*, 472 F. Supp. 3d 573, 613-14 (N.D. Cal. 2020). The EPA continues to center attention in this analysis on the global measures of the SC-GHG as the appropriate estimates given the flaws in the U.S. specific estimates, and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.

**Table 5-10. Estimated Climate Benefits from Changes in CO2 Emissions 2023 - 2040 (Millions of 2016$)[a]**

| | | Discount Rate and Statistic | | | |
|---|---|---|---|---|---|
| | 2030 | 150 | 479 | 694 | 1,447 |
| | 2035 | 175 | 530 | 757 | 1,618 |
| | 2040 | 231 | 671 | 945 | 2,062 |
| **Less-Stringent Alternative** | 2023 | 1 | 4 | 6 | 12 |
| | 2024 | 120 | 405 | 598 | 1,213 |
| | 2025 | 124 | 413 | 608 | 1,239 |
| | 2026 | 128 | 421 | 617 | 1,265 |
| | 2030 | 422 | 1,346 | 1,950 | 4,070 |
| | 2035 | 319 | 967 | 1,380 | 2,949 |
| | 2040 | 471 | 1,367 | 1,925 | 4,200 |

## 5.3 Total Human Health and Climate Benefits

Tables 5-11 through 5-13 present the total health and climate benefits for the final rule and the more and less stringent alternatives for 2023, 2026, and 2030.

**Table 5-11. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2023 (millions of 2016$)**

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) 3% | 7% | Climate Benefits Only[a] |
|---|---|---|---|
| Final Rule | | | |
| 5% (average) | $100 and $820 | $94 and $730 | $1 |
| 3% (average) | $100 and $820 | $98 and $740 | $5 |
| 2.5% (average) | $110 and $820 | $100 and $740 | $7 |
| 3% (95th percentile) | $110 and $830 | $110 and $750 | $14 |
| Less Stringent Alternative | | | |
| 5% (average) | $100 and $810 | $94 and $730 | $1 |
| 3% (average) | $100 and $820 | $97 and $730 | $4 |
| 2.5% (average) | $110 and $820 | $99 and $730 | $6 |
| 3% (95th percentile) | $110 and $830 | $100 and $740 | $12 |
| More Stringent Alternative | | | |
| 5% (average) | $110 and $840 | $97 and $750 | $1 |
| 3% (average) | $110 and $840 | $100 and $760 | $5 |

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) | | Climate Benefits Only[a] |
|---|---|---|---|
| | 3% | 7% | |
| 2.5% (average) | $120 and $850 | $100 and $760 | $7 |
| 3% (95th percentile) | $120 and $850 | $110 and $770 | $14 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon (SC-$CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).

**Table 5-12. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2026 (millions of 2016$)**

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) | | Climate Benefits Only[a] |
|---|---|---|---|
| | 3% | 7% | |
| Final Rule | | | |
| 5% (average) | $3,500 and $14,000 | $3,100 and $13,000 | $340 |
| 3% (average) | $4,300 and $15,000 | $3,900 and $13,000 | $1,100 |
| 2.5% (average) | $4,800 and $15,000 | $4,400 and $14,000 | $1,600 |
| 3% (95th percentile) | $6,600 and $17,000 | $6,200 and $16,000 | $3,400 |
| Less Stringent Alternative | | | |
| 5% (average) | $1,100 and $4,700 | $980 and $4,200 | $130 |
| 3% (average) | $1,400 and $5,000 | $1,300 and $4,500 | $420 |
| 2.5% (average) | $1,600 and $5,200 | $1,500 and $4,700 | $620 |
| 3% (95th percentile) | $2,200 and $5,800 | $2,100 and $5,400 | $1,300 |
| More Stringent Alternative | | | |
| 5% (average) | $8,900 and $30,000 | $13,000 and $27,000 | $640 |
| 3% (average) | $10,000 and $31,000 | $14,000 and $28,000 | $2,100 |
| 2.5% (average) | $11,000 and $32,000 | $15,000 and $29,000 | $3,100 |
| 3% (95th percentile) | $15,000 and $35,000 | $18,000 and $32,000 | $6,400 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon (SC-$CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).

**Table 5-13. Combined Health Benefits and Climate Benefits for the Final Rule and More and Less Stringent Alternatives for 2030 (millions of 2016$)**

| SC-$CO_2$ Discount Rate and Statistic | Health and Climate Benefits (Discount Rate Applied to Health Benefits) | | Climate Benefits Only[a] |
|---|---|---|---|
| | 3% | 7% | |
| Final Rule | | | |
| 5% (average) | $3,900 and $15,000 | $3,500 and $14,000 | $470 |

| | | | |
|---|---|---|---|
| 3% (average) | $4,900 and $16,000 | $4,500 and $15,000 | $1,500 |
| 2.5% (average) | $5,600 and $17,000 | $5,200 and $15,000 | $2,200 |
| 3% (95th percentile) | $8,000 and $19,000 | $7,600 and $18,000 | $4,600 |
| Less Stringent Alternative | | | |
| 5% (average) | $1,400 and $5,300 | $1,300 and $4,800 | $420 |
| 3% (average) | $2,300 and $6,200 | $2,300 and $5,700 | $1,300 |
| 2.5% (average) | $3,000 and $6,800 | $2,900 and $6,300 | $2,000 |
| 3% (95th percentile) | $5,100 and $8,900 | $5,000 and $8,400 | $4,100 |
| More Stringent Alternative | | | |
| 5% (average) | $9,200 and $31,000 | $8,300 and $28,000 | $150 |
| 3% (average) | $9,500 and $31,000 | $8,600 and $28,000 | $480 |
| 2.5% (average) | $9,700 and $32,000 | $8,800 and $28,000 | $700 |
| 3% (95th percentile) | $10,000 and $32,000 | $9,500 and $29,000 | $1,400 |

[a] Climate benefits are based on changes (reductions) in $CO_2$ emissions and are calculated using four different estimates of the social cost of carbon (SC-$CO_2$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate).

## 5.4 Additional Unquantified Benefits

Data, time, and resource limitations prevented the EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to $NO_2$ and $SO_2$ (independent of the role $NO_2$ and $SO_2$ play as precursors to ozone and $PM_{2.5}$), as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. While all health benefits and welfare benefits were not able to be quantified, it does not imply that there are not additional benefits associated with reductions in exposures to ozone, $PM_{2.5}$, $NO_2$ or $SO_2$.[141] In this section, we provide a qualitative description of these and water quality benefits, which are listed in Table 5-14.

**Table 5-14. Unquantified Health and Welfare Benefits Categories**

| Category | Effect | Effect Quantified | Effect Monetized | More Information |
|---|---|---|---|---|
| Improved Human Health | | | | |
| Reduced incidence of morbidity from exposure to $NO_2$ | Asthma hospital admissions | — | — | $NO_2$ ISA[1] |
| | Chronic lung disease hospital admissions | — | — | $NO_2$ ISA[1] |
| | Respiratory emergency department visits | — | — | $NO_2$ ISA[1] |
| | Asthma exacerbation | — | — | $NO_2$ ISA[1] |
| | Acute respiratory symptoms | — | — | $NO_2$ ISA[1] |
| | Premature mortality | — | — | $NO_2$ ISA[1,2,3] |

141 While not quantified in this RIA, we anticipate that the final rule may produce public health and welfare benefits for populations living in Canada and Mexico.

| Category | Effect | Effect Quantified | Effect Monetized | More Information |
|---|---|---|---|---|
| | Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations) | — | — | $NO_2$ ISA[2,3] |
| Reduced incidence of mortality and morbidity through drinking water from reduced effluent discharges. | Bladder, colon, and rectal cancer from halogenated disinfection byproducts exposure. | — | — | SE ELG BCA[4] |
| | Reproductive and developmental effects from halogenated disinfection byproducts exposure. | — | — | SE ELG BCA[4] |
| Reduced incidence of morbidity and mortality from toxics through fish consumption from reduced effluent discharges. | Neurological and cognitive effects to children from lead exposure from fish consumption (including need for specialized education). | — | — | SE ELG BCA[4] |
| | Possible cardiovascular disease from lead exposure | — | — | SE ELG BCA[4] |
| | Neurological and cognitive effects from in in-utero mercury exposure from maternal fish consumption | — | — | SE ELG BCA[4] |
| | Skin and gastrointestinal cancer incidence from arsenic exposure | — | — | SE ELG BCA[4] |
| | Cancer and non-cancer incidence from exposure to toxic pollutants (lead, cadmium, thallium, hexavalent chromium etc.<br><br>Neurological, alopecia, gastrointestinal effects, reproductive and developmental damage from short-term thallium exposure. | — | — | SE ELG BCA[4] |
| Reduced incidence of morbidity and mortality from recreational water exposure from reduced effluent discharges. | Cancer and Non-Cancer incidence from exposure to toxic pollutants (methyl-mercury, selenium, and thallium.) | — | — | SE ELG BCA[4] |
| Improved Environment | | | | |
| Reduced visibility impairment | Visibility in Class 1 areas | — | — | PM ISA[1] |
| | Visibility in residential areas | — | — | PM ISA[1] |
| Reduced effects on materials | Household soiling | — | — | PM ISA[1,2] |
| | Materials damage (e.g., corrosion, increased wear) | — | — | PM ISA[2] |
| Reduced effects from PM deposition (metals and organics) | Effects on individual organisms and ecosystems | — | — | PM ISA[2] |
| Reduced vegetation and ecosystem effects from exposure to ozone | Visible foliar injury on vegetation | — | — | Ozone ISA[1] |
| | Reduced vegetation growth and reproduction | — | — | Ozone ISA[1] |
| | Yield and quality of commercial forest products and crops | — | — | Ozone ISA[1] |
| | Damage to urban ornamental plants | — | — | Ozone ISA[2] |
| | Carbon sequestration in terrestrial ecosystems | — | — | Ozone ISA[1] |
| | Recreational demand associated with forest aesthetics | — | — | Ozone ISA[2] |
| | Other non-use effects | | | Ozone ISA[2] |
| | Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition) | — | — | Ozone ISA[2] |
| | Recreational fishing | — | — | $NO_x$ $SO_x$ ISA[1] |

| Category | Effect | Effect Quantified | Effect Monetized | More Information |
|---|---|---|---|---|
| Reduced effects from acid deposition | Tree mortality and decline | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Commercial fishing and forestry effects | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Recreational demand in terrestrial and aquatic ecosystems | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Other non-use effects | | | $NO_x$ $SO_x$ ISA[2] |
| | Ecosystem functions (e.g., biogeochemical cycles) | — | — | $NO_x$ $SO_x$ ISA[2] |
| Reduced effects from nutrient enrichment from deposition. | Species composition and biodiversity in terrestrial and estuarine ecosystems | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Coastal and liminal eutrophication | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Recreational demand in terrestrial and estuarine ecosystems | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Other non-use effects | | | $NO_x$ $SO_x$ ISA[2] |
| | Ecosystem functions (e.g., biogeochemical cycles, fire regulation) | — | — | $NO_x$ $SO_x$ ISA[2] |
| Reduced vegetation effects from ambient exposure to $SO_2$ and $NO_x$ | Injury to vegetation from $SO_2$ exposure | — | — | $NO_x$ $SO_x$ ISA[2] |
| | Injury to vegetation from $NO_x$ exposure | — | — | $NO_x$ $SO_x$ ISA[2] |
| Improved water aesthetics from reduced effluent discharges. | Improvements in water clarity, color, odor in residential, commercial and recreational settings. | — | — | SE ELG BCA[4] |
| Effects on aquatic organisms and other wildlife from reduced effluent discharges | Protection of Threatened and Endangered (T&E) species from changes in habitat and potential population effects. | — | — | SE ELG BCA[4] |
| | Other non-use effects | — | — | SE ELG BCA[4] |
| | Changes in sediment contamination on benthic communities and potential for re-entrainment. | — | — | SE ELG BCA[4] |
| | Quality of recreational fishing and other recreational use values. | — | — | SE ELG BCA[4] |
| | Commercial fishing yields and harvest quality. | — | — | SE ELG BCA[4] |
| Reduced water treatment costs from reduced effluent discharges | Reduced drinking, irrigation, and other agricultural use water treatment costs. | — | — | SE ELG BCA[4] |
| Reduced sedimentation from effluent discharges | Increased storage availability in reservoirs | — | — | SE ELG BCA[4] |
| | Improved functionality of navigable waterways | — | — | SE ELG BCA[4] |
| | Decreased cost of dredging | — | — | SE ELG BCA[4] |
| Benefits of reduced water withdrawal | Benefits from effects aquatic and riparian species from additional water availability. | — | — | SE ELG BCA[4] |
| | Increased water availability in reservoirs increasing hydropower supply, recreation, and other services. | — | — | SE ELG BCA[4] |
| Climate effects | Climate impacts from carbon dioxide ($CO_2$) | --- | --- | Section 5.2 discussion |
| | Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts) | | | IPCC, Ozone ISA, PM ISA |

[1] We assess these benefits qualitatively due to data and resource limitations for this RIA

[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods

[3] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association

[4] Benefit and Cost Analysis (BCA) for Revisions to the Effluent Limitations Guidelines (ELG) and Standards for the Steam Electric (SE) Power Generating Point Source Category.

### *5.4.1 $NO_2$ Health Benefits*

In addition to being a precursor to ozone and $PM_{2.5}$, NOx emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced $NO_2$ exposure in this analysis. Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment for Oxides of Nitrogen —Health Criteria (NOx ISA) (U.S. EPA, 2016c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to $NO_2$. These epidemiologic and experimental studies encompass a number of endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NOx ISA also concluded that the relationship between short-term $NO_2$ exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship," because it is difficult to attribute the mortality risk effects to $NO_2$ alone. Although the NOx ISA stated that studies consistently reported a relationship between $NO_2$ exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

### *5.4.2 $SO_2$ Health Benefits*

In addition to being a precursor to $PM_{2.5}$, $SO_2$ emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health benefits associated with reduced $SO_2$ in this analysis. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ benefits associated with the reductions in $SO_2$ emissions. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Sulfur —Health Criteria* ($SO_2$ ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to $SO_2$ (U.S. EPA 2017). The immediate effect of $SO_2$ on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of $SO_2$ likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to $SO_2$ at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified three short-term morbidity endpoints that the $SO_2$ ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the $SO_2$ ISA. The $SO_2$ ISA also concluded that the relationship between short-term $SO_2$ exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to $SO_2$ alone. Although the $SO_2$ ISA stated that studies are generally consistent in reporting a relationship between $SO_2$ exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants.

#### *5.4.3 Ozone Welfare Benefits*

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020b). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services. See Section F of the *Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, Ozone Transport Policy Analysis Proposed Rule TSD* for a summary of an assessment of risk of ozone-related growth impacts on selected forest tree species.

#### *5.4.4 $NO_2$ and $SO_2$ Welfare Benefits*

As described in the Integrated Science Assessment (ISA) for Oxides of Nitrogen, Oxides of Sulfur and Particulate Matter Ecological Criteria (NOx/SOx/PM ISA) (U.S. EPA, 2020d), NOx and $SO_2$ emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen and sulfur causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, restricting the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008b)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In lake and estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires. (U.S. EPA, 2008b)

*5.4.5 Visibility Impairment Benefits*

Reducing secondary formation of $PM_{2.5}$ under the Regional Haze Rule would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2009). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA, 2009). Previous analyses (U.S. EPA, 2011a) show that visibility benefits can be a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility-related benefits, and we are also unable to determine whether the emissions reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas.

Reductions in emissions of $NO_2$ will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA, 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA, 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U. S. EPA, 2009).

### *5.4.6 Water Quality and Availability Benefits*

As described in Chapter 4, this rule is expected to lead to shifts in electricity production away from fossil-fired steam generation towards renewable and natural gas generation. There are several negative health, ecological, and productivity effects associated with water effluent and intake from coal generation that will be avoided, and the benefits are qualitatively described below. [142] For additional discussion of these effects and their consequent effect on welfare, see the *Benefit and Cost Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA 2020a).

#### *5.4.6.1 Potential Water Quality Benefits of Reducing Coal-Fired Power Generation*

Discharges of wastewater from coal-fired power plants can contain toxic and bioaccumulative pollutants (e.g., selenium, mercury, arsenic, nickel), halogen compounds (containing bromide, chloride, or iodide), nutrients, and total dissolved solids (TDS), which can

[142] While natural gas combined cycle units also emit wastewater effluents and withdrawal demands, which offset some of the benefits of reduced fossil steam generation, the scale of these waste streams is much smaller than for other fossil steam generator types.

cause human health and environmental harm through surface water and fish tissue contamination. Pollutants in coal combustion wastewater are of particular concern because they can occur in large quantities (i.e., total pounds) and at high concentrations in discharges and leachate to groundwater and surface waters. These potential beneficial effects follow directly from reductions in pollutant loadings to receiving waters, and indirectly from other changes in plant operations. The potential benefits come in the form of reduced morbidity, mortality, and on environmental quality and economic activities; reduction in water use, which provides benefits in the form of increased availability of surface water and groundwater; and reductions in the use of surface impoundments to manage Coal Combustion Residual wastes, with benefits in the form of avoided cleanup and other costs associated with impoundment releases.

Reducing coal-fired power generation affects human health risk by changing exposure to pollutants in water via two principal exposure pathways: (1) treated water sourced from surface waters affected by coal-fired power plant discharges and (2) fish and shellfish taken from waterways affected by coal-fired power plant discharges. The human health benefits from surface water quality improvements may include drinking water benefits, fish consumption benefits, and other complimentary measures.

In addition, reducing coal-fired power generation can affect the ecological condition and recreation use effects from surface water quality changes. The EPA expects the ecological impacts from reducing coal-fired power plant discharges could include habitat changes for fresh- and saltwater plants, invertebrates, fish, and amphibians, as well as terrestrial wildlife and birds that prey on aquatic organisms exposed to pollutants from coal combustion. The change in pollutant loadings has the potential to result in changes in ecosystem productivity in waterways and the health of resident species, including threatened and endangered (T&E) species. Loadings from coal-fired power generation have the potential to impact the general health of fish and invertebrate populations, their propagation to waters, and fisheries for both commercial and recreational purposes. Changes in water quality also have the potential to impact recreational activities such as swimming, boating, fishing, and water skiing.

Potential economic productivity effects may stem from changes in the quality of public drinking water supplies and irrigation water; changes in sediment deposition in reservoirs and navigational waterways; and changes in tourism, commercial fish harvests, and property values.

*5.4.6.2 Drinking Water*

Pollutants discharged by coal-fired power plants to surface waters may affect the quality of water used for public drinking supplies. In turn these impacts to public water supplies have the potential to affect the costs of drinking water treatment (e.g., filtration and chemical treatment) by changing eutrophication levels and pollutant concentrations in source waters. Eutrophication is one of the main causes of taste and odor impairment in drinking water, which has a major negative impact on public perceptions of drinking water safety. Additional treatment to address foul tastes and odors to bring the finished water into compliance with EPA's National Secondary Drinking Water Treatment Standards can significantly increase the cost of public water supply. Likewise, public drinking water supplies are subject to National Primary Drinking Water Standards that have set legally enforceable maximum contaminant levels (MCLs), for a number of pollutants, like metals, discharged from coal-fired power plants. Drinking water systems downstream from these power plants may be required to treat source water to remove the contaminants to levels below the MCL in the finished water. This treatment will also increase costs at drinking water treatment plants. Episodic releases from coal fired power plants, may be detected only after the completion of a several-month round of compliance monitoring at drinking water treatment plants and there could also by a lag between detection of changes in source water contaminants and the system implementing treatment to address the issue. This lag may result in consumers being exposed to these contaminants through ingestion, inhalation, and skin absorption. The constituents found in the power plant discharge may also interact with drinking water treatment processes and contribute to the formation of disinfection byproducts that can have adverse human health impacts.

*5.4.6.3 Fish Consumption*

Recreational and subsistence fishers (and their household members) who consume fish caught in the reaches downstream of coal-fired power plants may be affected by changes in pollutant concentrations in fish tissue. See the *Benefit and Cost Analysis for Revisions to the*

*Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA 2020a) for a demonstration of the changes in risk to human health from exposure to contaminated fish tissue. This document describes the neurological effects to children ages 0 to 7 from exposure to lead; the neurological effects to infants from in-utero exposure to mercury; the incidence of skin cancer from exposure to arsenic; and the reduced risk of other cancer and non-cancer toxic effects.

*5.4.6.4 Changes in Surface Water Quality*

Reducing coal-fired power plant discharges may affect the value of ecosystem services provided by surface waters through changes in the habitats or ecosystems (aquatic and terrestrial). Society values changes in ecosystem services by a number of mechanisms, including increased frequency of use and improved quality of the habitat for recreational activities (e.g., fishing, swimming, and boating). Individuals also value the protection of habitats and species that may reside in waters that receive water discharges from coal-plants, even when those individuals do not use or anticipate future use of such waters for recreational or other purposes, resulting in nonuse values.

*5.4.6.5 Impacts on Threatened and Endangered Species*

For T&E species, even minor changes to reproductive rates and mortality levels may represent a substantial portion of annual population variation. Therefore, changing the discharge of coal-fired power plant pollutants to aquatic habitats has the potential to impact the survivability of some T&E species living in these habitats. The economic value for these T&E species primarily comes from the nonuse values people hold for the survivorship of both individual organisms and species survival.

*5.4.6.6 Changes in Sediment Contamination*

Water effluent discharges from coal-fired power plants can also contaminate waterbody sediments. For example, sediment adsorption of arsenic, selenium, and other pollutants found in water discharges can result in accumulation of contaminated sediment on stream and lake beds, posing a particular threat to benthic (i.e., bottom-dwelling) organisms. These pollutants can later be re-released into the water column and enter organisms at different trophic levels. Concentrations of selenium and other pollutants in fish tissue of organisms of lower trophic levels can bio-magnify through higher trophic levels, posing a threat to the food chain at large (Ruhl et al., 2012).

*5.4.6.7 Reservoir Capacity and Sedimentation Changes in Navigational Waterways*

Reservoirs serve many functions, including storage of drinking and irrigation water supplies, flood control, hydropower supply, and recreation. Streams can carry sediment into reservoirs, where it can settle and cause buildup of sediment layers over time, reducing reservoir capacity (Graf et al., 2010, 2011) and the useful life of reservoirs unless measures such as dredging are taken to reclaim capacity (Hargrove et al., 2010; Miranda, 2017). Likewise, navigable waterways, including rivers, lakes, bays, shipping channels and harbors, are prone to reduced functionality due to sediment build-up, which can reduce the navigable depth and width of the waterway (Clark et al., 1985; Ribaudo and Johansson, 2006). For many navigable waters, periodic dredging is necessary to remove sediment and keep them passable. Dredging of reservoirs and navigable waterways can be costly. The EPA expects that changes in suspended solids effluent discharge from coal-fired power plants could reduce sediment loadings to surface waters decreasing reservoir and navigable waterway maintenance costs by changing the frequency or volume of dredging activity.

*5.4.6.8 Changes in Water Consumption and Withdrawals*

A reduction in water consumption from coal fired power plants may benefit aquatic and riparian species downstream of the power plant intake through the provision of additional water resources in the face of drying conditions and increased rainfall variability. In a study completed, in 2011, by the U.S. Department of Energy's National Renewable Energy Laboratory (U.S. DOE 2011), water consumption, which is defined as water removed from the immediate water environment and can include cooling water evaporation, cleaning, and process related water use including flue gas desulfurization, was found to range from 100 – 1,100 gal/MWh at generic coal power plants. This study also found that water withdraws, defined as the amount of water removed from the ground or diverted from a water source for use, ranged from 300 – 50,000 gal/MWh at a generic coal power plant. Reductions in water consumption and withdraws will lower the number of aquatic organisms impinged and entrained by the power plant's water filtration and cooling systems.

*5.4.7 Hazardous Air Pollutant Impacts*

The rule is expected to reduce fossil-fired EGU generation and consequentially is expected to lead to reduced HAP emissions. HAP emissions from EGUs create risks of premature mortality from heart attacks, cancer, and neurodevelopmental delays in children, and detrimentally affect economically vital ecosystems used for recreational and commercial purposes. Further, these public health effects are particularly pronounced for certain segments of the American population that are especially vulnerable (*e.g.*, subsistence fishers and their children) to impacts from EGU HAP emissions.

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# CHAPTER 6: ECONOMIC IMPACTS

## Overview

Economic impact analyses focus on changes in market prices and output levels. If changes in market prices and output levels in the primary markets are significant enough, impacts on other markets may also be examined. Both the magnitude of costs needed to comply with a rule and the distribution of these costs among affected facilities can have a role in determining how the market will change in response to a rule. This chapter analyzes the potential impacts on small entities and the potential labor impacts associated with this rulemaking. For additional discussion of impacts on fuel use and electricity prices, see Chapter 4, Section 4.5.*1*

## 6.1 Small Entity Analysis

For the final rule, the EPA performed a small entity screening analysis for impacts on all affected EGUs and non-EGU facilities by comparing compliance costs to historic revenues at the ultimate parent company level. This is known as the cost-to-revenue or cost-to-sales test, or the "sales test." The sales test is an impact methodology the EPA employs in analyzing entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by the EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the Regulatory Flexibility Act (RFA)[143] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (SBA, 2017).

### *6.1.1 EGU Small Entity Analysis and Results*

This section presents the methodology and results for estimating the impact of the rule on small EGU entities in 2026 based on the following endpoints:

- annual economic impacts of the rule on small entities, and

[143] The RFA compliance guidance to the EPA rule writers can be found at <https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf >

- ratio of small entity impacts to revenues from electricity generation.

In this analysis, the EPA considered EGUs that are subject to the FIP and meet the following five criteria: 1) EGU is represented in NEEDS v6; 2) EGU is fossil fuel-fired; 3) EGU is located in a state covered by this rule; 4) EGU is neither a cogeneration unit nor solid waste incineration unit; and 5) EGU capacity is 25 Megawatt (MW) or larger. EPA next refined this list of EGUs, narrowing it to those that exhibit at least one of the following changes, in comparison to the baseline. Please see Chapter 4, Section 4.3 for more discussion of the power sector modeling.

- Summer fuel use (BTUs) changes by +/- 1 percent or more
- Summer generation (GWh) changes by +/- 1 percent or more
- NOx summer emissions (tons) changes by +/- 1 percent or more

Based on these criteria, the EPA identified a total of 436 potentially affected EGUs warranting examination in 2026 in this RFA analysis. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. We primarily used data from Ventyx, supplemented by limited research using publicly available data.[144] Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[145] These ownership types are:

1. **Investor-Owned Utility (IOU)**: Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. **Cooperative (Co-Op)**: Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. **Municipal**: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division**: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. **Private**: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.

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[144] The Ventyx Energy Velocity Suite database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.ventyx.com.

[145] Throughout this analysis, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

6. **State**: Utility owned by the state.
7. **Federal**: Utility owned by the federal government.

Next, the EPA used both the D&B Hoovers online database and the Ventyx database to identify the ultimate owners of power plant owners identified in the Ventyx database. This was necessary, as many majority owners of power plants (listed in Ventyx) are themselves owned by other ultimate parent entities (listed in D&B Hoovers).[146] In these cases, the ultimate parent entity was identified via D&B Hoovers, whether domestically or internationally owned.

The EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small.[147] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[148] and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity to understand the appropriate size standard to apply. Data from D&B Hoovers was used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 6-1. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in EPA's IPM base case.

**Table 6-1. SBA Size Standards by NAICS Code**

| NAICS Codes | NAICS U.S. Industry Title | Size Standards (Millions of dollars) | Size Standards (Number of employees) |
|---|---|---|---|
| 221111 | Hydroelectric Power Generation | | 500 |
| 221112 | Fossil Fuel Electric Power Generation | | 750 |
| 221113 | Nuclear Electric Power Generation | | 750 |

[146] The D&B Hoovers online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: https://www.dnb.com/products/marketing-sales/dnb-hoovers.html.
[147] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.
[148] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/

| NAICS Codes | NAICS U.S. Industry Title | Size Standards (Millions of dollars) | Size Standards (Number of employees) |
|---|---|---|---|
| 221114 | Solar Electric Power Generation | | 250 |
| 221115 | Wind Electric Power Generation | | 250 |
| 221116 | Geothermal Electric Power Generation | | 250 |
| 221117 | Biomass Electric Power Generation | | 250 |
| 221118 | Other Electric Power Generation | | 250 |
| 221121 | Electric Bulk Power Transmission and Control | | 500 |
| 221122 | Electric Power Distribution | | 1,000 |
| 221210 | Natural Gas Distribution | | 1,000 |
| 221310 | Water Supply and Irrigation Systems | $41.0 | |
| 221320 | Sewage Treatment Facilities | $35.0 | |
| 221330 | Steam and Air-Conditioning Supply | $30.0 | |

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective December 19, 2022. Available at the following link: https://www.sba.gov/document/support--table-size-standards).
Source: SBA, 2022

The EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 6-1. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

1. **Employment, Revenue, and Assets**: EPA used the D&B Hoovers database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[149] In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of IPM parsed file[150] estimates for the baseline run for 2023 and 2026. EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited instances, supplemental research was also conducted to estimate an ultimate parent entity's number of employees, revenue, or assets.
2. **Population**: Municipal entities are defined as small if they serve populations of less than 50,000.[151] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

[149] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.
[150] IPM output files report aggregated results for "model" plants (i.e., aggregates of generating units with similar operating characteristics). Parsed files approximate the IPM results at the generating unit level.
[151] The Regulatory Flexibility Act defines a small government jurisdiction as the government of a city, county, town, township, village, school district, or special district with a population of less than 50,000 (5 U.S.C. section 601(5)). For the purposes of the RFA, States and tribal governments are not considered small governments. EPA's *Final Guidance for EPA Rulewriters: Regulatory Flexibility Act* is located here: https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf.

Ultimate parent entities for which the relevant measure is less than the SBA size standard were identified as small entities and carried forward in this analysis.

In 2026, EPA identified 436 potentially affected EGUs, owned by 75 entities. Of these, the EPA identified 71 potentially affected EGUs owned by 19 small entities included in the power sector baseline.

In 2023, an entity can comply with the Final Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) through some combination of the following: optimizing existing SCRs, optimizing existing SNCR controls, installing state-of-the-art combustion controls, using allocated allowances, purchasing allowances, or reducing emissions through a reduction in generation. Additionally, units with more allowances than needed can sell these allowances in the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units. In addition to the 2023 compliance options, in 2026 an entity can comply with the Transport FIP for the 2015 ozone NAAQS by installing SCR or SNCR retrofits.

To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ C_{Allowances} + \Delta\ C_{Transaction} + \Delta\ R$$

where $C$ represents a component of cost as labeled[152], and $\Delta$ R represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the rule in in 2026.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a reduction in any of the individual components of cost. Under the rule, some units will forgo some level of electricity generation (and thus revenues) to comply, and this impact will be lessened on these entities by the projected increase in electricity prices under the rule. On the other hand, those units increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately, they will have negative net

[152] Retrofit costs include the costs of fully operating existing controls, as well as the installation of state-of-the-art combustion controls, SCRs and SNCRs.

compliance costs (or increased profit). Overall, small entities are not projected to install relatively costly emissions control retrofits if it can be avoided while still complying with the rule but may choose to do so in some instances. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures gains such as those described. As a result, what we describe as cost is actually a measure of the net economic impact of the rule on small entities.

For this analysis, the EPA used IPM-parsed output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the Transport FIP for the 2015 ozone NAAQS relative to the base case. These individual components of compliance costs were estimated as follows:

**(1)** **Operating and retrofit costs** ($\Delta\ C_{Operating+Retrofit}$)**:** Using engineering analytics, EPA identified which compliance option would be selected by each EGU in 2023 (i.e., SCR/SNCR optimization and/or installing state-of-the-art combustion controls) and applied the appropriate cost to this choice (for details, please see Chapter 4 of this RIA). For 2026, IPM projected retrofit costs were also included in the calculation.

**(2)** **Sale or purchase of allowances** ($\Delta\ C_{Allowances}$)**:** To estimate the value of allowance holdings, allocated allowances were subtracted from projected emissions, and the difference was then multiplied by model projected allowance costs. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the Transport FIP for the 2015 ozone NAAQS.

**(3)** **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the Transport FIP for the 2015 ozone NAAQS was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the Transport FIP for the 2015 ozone NAAQS and the baseline.

**(4)** **Value of electricity generated:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price ($/MWh) estimate, for all entities except those categorized as private in Ventyx. See Chapter 4, Section 4.5.3 for a discussion of the Retail

Price Model, which was used to estimate the change in the retail price of electricity. For private entities, EPA used the wholesale electricity price instead of the retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities. Thus, their revenue was estimated with wholesale electricity prices.

**(5)** **Administrative costs** ($\Delta\ C_{Transaction}$)**:** Because most affected units are already monitored as a result of other regulatory requirements, EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of the difference between a unit's allocation and projected $NO_X$ emissions. This assumption is based on market research by ICF.

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the RFA and is consistent with guidance published by the SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. The potential impacts, including compliance costs, of the Transport FIP for the 2015 ozone NAAQS on small entities are summarized in Table 6-2. All costs are presented in 2016$. EPA estimated the annual net compliance cost to small entities to be approximately $18 million in 2026.

**Table 6-2. Projected Impact of the Transport FIP for the 2015 Ozone NAAQS on Small Entities in 2026**

| EGU Ownership Type | Number of Potentially Affected Entities | Total Net Compliance Cost ($2016 millions) | Number of Small Entities with Compliance Costs >1% of Generation Revenues |
|---|---|---|---|
| Municipal | 6 | 1.0 | 0 |
| Private | 5 | 0.5 | 0 |
| Co-op | 8 | 16.6 | 0 |
| **Total** | **19** | **18.1** | **0** |

**Source: IPM analysis**

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 19 entities considered in this analysis, none are projected to experience compliance costs greater than 1% of generation revenues in 2026.

### *6.1.2 Non-EGU Small Entity Impacts and Results*

We identified 1,228 emissions units, discussed in Chapter 4, owned by 137 parent companies, using information from D&B Hoovers,[153] that could be affected by the final rule. Of the parent companies, 10 companies, or seven percent, are small entities. We also used information from D&B Hoovers for the parent company revenues. We identified the NAICS code for all parent companies and applied the most current version of SBA's table of size standards to determine which of the companies were small entities. Table 6-3 below includes the ranges NAICS codes and SBA entity size guidelines for small entity parent companies.

**Table 6-3. Non-EGU SBA Size Standards by NAICS Code**

| NAICS Codes | NAICS U.S. Industry Title | Size Standards (million$) | Size Standards (Number of employees) |
|---|---|---|---|
| 212290 | Other Metal Ore Mining | | 750 |
| 327211 | Flat Glass Manufacturing | | 1,000 |
| 327212 | Other Pressed and Blown Glass and Glassware Manufacturing | | 1,250 |
| 327213 | Glass Container Manufacturing | | 1,250 |
| 327310 | Cement Manufacturing | | 1,000 |
| 331110 | Iron and Steel Mills and Ferroalloy Manufacturing | | 1,500 |
| 486210 | Pipeline Transportation of Natural Gas | $36.5 | |
| 322110 | Pulp Mills | | 750 |
| 322120 | Paper (except Newsprint) Mills | | 1,250 |
| 322130 | Paperboard Mills | | 1,250 |
| 324110 | Petroleum Refineries | | 1,500 |
| 324199 | All Other Petroleum and Coal Products Manufacturing | | 500 |
| 325110 | Petrochemical Manufacturing | | 1,000 |
| 325180 | Other Basic Inorganic Chemical Manufacturing | | 1,000 |
| 325199 | All Other Basic Organic Chemical Manufacturing | | 1,250 |
| 562213 | Solid Waste Combustors and Incinerators | $41.5 | |

[153] D&B Hoovers is a subscription-based database that compiles publicly available information and can be found at https://www.dnb.com/products/marketing-sales/dnb-hoovers.html.

In addition, we identified several waste combustors owned by government entities at the county or city level. When evaluating the small entity impact to a government-owned facility the size of the population served by that government should be used as the basis for the small entity screening. In our analysis we identified 17 emissions units owned by five separate jurisdictions. None of the populations served by those governments are below the threshold for inclusion as a small entity.

We calculated the cost-to-sales ratios for all of the affected entities to determine (i) the magnitude of the costs of the rule, and (ii) whether there would be a significant impact on small entities compared to large entities. Non-EGUs do not operate in a price-regulated environment, like EGUs, where they are able to recover expenses through rate increases. As presented in Table 6-4 for *all* firms the average cost-to-sales ratio is approximately 0.2 percent; the median cost-to-sales ratio is less than 0.1 percent; and the maximum cost-to-sales ratio is approximately 2.4 percent. For *large* firms, the average cost-to-sales ratio is approximately 0.1 percent; the median cost-to-sales ratio is less than 0.1 percent; and the maximum cost-to-sales ratio is approximately 1.1 percent. For *small* firms, the average cost-to-sales ratio is approximately 0.8 percent, the median cost-to-sales ratio is 0.7 percent, and the maximum cost-to-sales ratio is 2.4 percent.

**Table 6-4. Summary of Sales Test Ratios for 2026 for Firms Affected by Proposed Rule**

| Firm Size | No. of Known Affected Firms | % of Total Known Affected Firms | Mean Cost-to-Sales Ratio | Median Cost-to-Sales Ratio | Min. Cost-to-Sales Ratio | Max. Cost-to-Sales Ratio |
|---|---|---|---|---|---|---|
| Small | 10 | 7.3% | 0.8% | 0.7% | <0.0% | 2.4% |
| Large | 127 | 92.7% | 0.1% | <0.0% | <0.0% | 1.1% |
| All | 137 | 100.0% | 0.2% | <0.0% | <0.0% | 2.4% |

As mentioned above, we compare annual compliance costs to annual revenues at the ultimate parent company level. Table 6-5 below includes the small parent companies and their projected cost-to-sales ratio, NAICS code, and small business size standards. The costs for the small parent companies ranged from $12 thousand to $2.3 million annually (2016$).

**Table 6-5. Summary of Small Parent Company Small Business Size Standards**

| Small Parent Company | NAICS | Cost to Sales Ratio | Small Parent Number of Employees | SBA Business Small Size Standards: Annual Revenue (million$) | SBA Business Small Size Standards: Number of Employees |
|---|---|---|---|---|---|
| ND Fairmont LLC | 322110 | 0.96% | 250 | | 750 |
| Cobra Pipeline Company[a] | 486210 | 2.40% | 13 | 36.5 | |
| Angus Chemical Company | 325199 | 1.76% | 500 | | 1,250 |
| Cstn Holdings | 325199 | 0.86% | 600 | | 1,250 |
| Empire Pipeline Corp[a] | 486210 | 0.22% | 8 | 36.5 | |
| FutureFuel Chemical | 325199 | 0.51% | 460 | | 1,250 |
| Bear Island Paper Wb LLC | 322120 | 0.73% | 190 | | 1,250 |
| Deltech LLC | 325110 | 0.61% | 100 | | 1,000 |
| American Eagle Paper Mills | 322120 | 0.42% | 240 | | 1,250 |
| Savant Inc. | 327212 | 0.03% | 927 | | 1,250 |

[a] These small entity parent companies were evaluated using the size standard for annual revenues.

### *6.1.3 Conclusion*

Making a no SISNOSE (significant economic impacts on a substantial number of small entities) determination reflects an assessment of whether an estimated economic impact is significant and whether that impact affects a substantial number of small entities. We prepared an analysis of small entity impacts for EGUs and non-EGUs in 2026 separately and combined the 2026 results for a SISNOSE determination for the rule.

For EGUs in 2026, the analysis indicates that 19 small entities see a +/- 1 percent change in either summer NOx emissions, summer generation or summer fuel use, and none of these are projected to have a cost impact of greater than 1 percent of their revenues.

In 2026, the EPA identified 71 possibly affected EGU entities. Of these, the EPA identified 19 small entities affected by the rule, and of these no small entities may experience costs of greater than 1 percent of revenues. The EPA's decision to exclude units smaller than 25 MW capacity from the FIP, and exclusion of uncontrolled units smaller than 100 MW from the backstop emission rate has already significantly reduced the burden on small entities by reducing the number of affected small entity-owned units. Further, in 2026 for non-EGUs, there are 10 small entities, and two small entities are estimated to have a cost-to-sales impact of more than one percent of their revenues.

Based on this analysis, for this rule overall we conclude that the estimated costs for the final rule will not have a significant economic impact on a substantial number of small entities (SISNOSE).

**6.2 Labor Impacts**

This section discusses potential employment impacts of this regulation. As economic activity shifts in response to a regulation, typically there will be a mix of declines and gains in employment in different parts of the economy over time and across regions. To present a complete picture, an employment impact analysis will describe the potential positive and negative changes in employment levels. There are significant challenges when trying to evaluate the employment effects due to an environmental regulation due to a wide variety of other economic changes that can affect employment, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. Considering these challenges, we look to the economics literature to provide a constructive framework and empirical evidence. To simplify, we focus on impacts on labor demand related to compliance behavior. Environmental regulation may also affect labor supply through changes in worker health and productivity (Graff, Zivin and Neidell, 2018).

Economic theory of labor demand indicates that employers affected by environmental regulation may increase their demand for some types of labor, decrease demand for other types, or for still other types, not change it at all (Morgenstern et al. 2002, Deschênes 2018, Berman and Bui 2001). To study labor demand impacts empirically, a growing literature has compared employment levels at facilities subject to an environmental regulation to employment levels at similar facilities not subject to that environmental regulation; some studies find no employment effects, and others find significant differences. For example, see Berman and Bui (2001), Greenstone (2002), Ferris, Shadbegian and Wolverton (2014), and Curtis (2018, 2020).

A variety of conditions can affect employment impacts of environmental regulation, including baseline labor market conditions and employer and worker characteristics such as occupation and industry. Changes in employment may also occur in different sectors related to the regulated industry, both upstream and downstream, or in sectors producing substitute or complimentary products.  Employment impacts in related sectors are often difficult to measure.

Consequently, we focus our labor impacts analysis primarily on the directly regulated facilities and other EGUs and related fuel markets and in the different non-EGU industry sectors.

### *6.2.1 EGU Labor Impacts*

This section discusses and projects potential employment impacts for the utility power, coal and natural gas production sectors that may result from the rule. EPA has a long history of analyzing the potential impacts of air pollution regulations on changes in the amount of labor needed in the power generation sector and directly related sectors. The analysis conducted for this RIA builds upon the approaches used in the past and takes advantage of newly available data to improve the assumptions and methodology.[154]

The results presented in this section are based on a methodology that estimates the impact on employment based on the differences in projections between two modeling scenarios: the baseline scenario, and a scenario that represents the implementation of the rule. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the rule on employment in this sector. As discussed in Chapter 4, there is uncertainty related to the future baseline projections, in part due to unknown impacts of the Inflation Reduction Act. Because the incremental employment estimates presented in this section are based on projections discussed in Chapter 4, it is important to highlight the relevance of the Chapter 4 uncertainty discussion to the analysis presented in this section.

Like previous analyses, this analysis represents an evaluation of "first-order employment impacts" using a partial equilibrium modeling approach. It includes some of the potential ripple effects of these impacts on the broader economy. These ripple effects include the secondary job impacts in both upstream and downstream sectors. The analysis includes impacts on upstream sectors including coal, natural gas, and uranium. However, the approach does not analyze impacts on other fuel sectors, nor does it analyze potential impacts related to transmission, distribution, or storage. This approach excludes the economy-wide employment effects of changes to energy markets (such as higher or lower forecasted electricity prices). This approach also excludes labor impacts that are sometimes reflected in a benefits analysis for an

[154] For a detailed overview of this methodology, including all underlying assumptions, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

environmental policy, such as increased productivity from a healthier workforce and reduced absenteeism due to fewer sick days of employees and dependent family members (e.g., children).

### *6.2.2 Overview of Methodology*

The methodology includes the following two general approaches, based on the available data. The first approach utilizes the rich employment data that is available for several types of generation technologies in the 2020 U.S. Energy and Employment Report.[155] For employment related to other electric power sector generating and pollution control technologies, the second approach utilizes information available in the U.S. Economic Census.

Detailed employment inventory data is available regarding recent employment related to coal, hydro, natural gas, geothermal, wind, and solar generation technologies. The data enables the creation of technology-specific factors that can be applied to model projections of capacity (reported in megawatts, or MW) and generation (reported in megawatt-hours, or MWh) in order to estimate impacts on employment. Since employment data is only available in aggregate by fuel type, it is necessary to disaggregate by labor type in order to differentiate between types of jobs or tasks for categories of workers. For example, some types of employment remain constant throughout the year and are largely a function of the size of a generator, e.g., fixed operation and maintenance activities, while others are variable and are related to the amount of electricity produced by the generator, e.g., variable operation and maintenance activities.

The approach can be summarized in three basic steps:

- Quantify the total number of employees by fuel type in a given year;
- Estimate total fixed operating & maintenance (FOM), variable operating & maintenance (VOM), and capital expenditures by fuel type in that year; and
- Disaggregate total employees into three expenditure-based groups and develop factors for each group (FTE/MWh, FTE/MW-year, FTE/MW new capacity).

Where detailed employment data is unavailable, it is possible to estimate labor impacts using labor intensity ratios. These factors provide a relationship between employment and

[155] https://www.usenergyjobs.org/

economic output and are used to estimate employment impacts related to construction and operation of pollution control retrofits, as well as some types of electric generation technologies.

For a detailed overview of this methodology, including all underlying assumptions and the types of employment represented by this analysis, see the U.S. EPA Methodology for Power Sector-Specific Employment Analysis, available in the docket.

*6.2.3 Overview of Power Sector Employment*

In this section we focus on employment related to electric power generation, as well as coal and natural gas extraction because these are the segments of the power sector that are most relevant to the projected impacts of the rule. Other segments not discussed here include other fuels, energy efficiency, and transmission, distribution, and storage. The statistics presented here are based on the 2020 USEER, which reports data from 2019.[156]

In 2019, the electric power generation sector employed nearly 900,000 people. Relative to 2018, this sector grew by over 2 percent, despite job losses related to nuclear and coal generation. These losses were offset by increases in employment related to other generating technologies, including natural gas, solar, and wind. The largest component of total 2019 employment in this sector is construction (33%). Other components of the electric power generation workforce include utility workers (20%), professional and business service employees (20%), manufacturing (13%), wholesale trade (8%), and other (5%). In 2019, jobs related to solar and wind generation represent 31% and 14% of total jobs, respectively, and jobs related to coal generation represent 10% of total employment.

In addition to generation-related employment we also look at employment related to coal and natural gas use in the electric power sector. In 2019, the coal industry employed about 75,000 workers. Mining and extraction jobs represent the vast majority of total coal-related employment in 2019 (74%). The natural gas fuel sector employed about 276,000 employees in 2019. About 60% of those jobs were related to mining and extraction.

[156] While 2020 data is available in the 2021 version of this report, this section of the RIA utilizes 2019 data because this year does not reflect any short-term trends related to the COVID-19 pandemic. The annual report is available at: https://www.usenergyjobs.org/.

*6.2.4 Projected Sectoral Employment Changes due to the Final Rule*

Affected EGUs may respond to the rule through a number of means including optimizing existing controls, upgrading to state-of-the-art combustion controls, shifting generation from higher emitting to lower emitting sources, and installing new SCRs and SNCRs. Under the modeling of the final rule, 8 GW of SCR installations are projected by the 2030 run year, and an incremental 14 GW of coal retirements are projected by 2030. Additionally, EPA's modeling of this rule projects an incremental 3 GW of non-hydro renewable additions, by 2025, and an additional 1 GW of non-hydro renewable and 9 GW of natural gas capacity by the 2030 run year.

Based on these power sector modeling projections, we estimate an increase in construction-related job-years related to the installation of new pollution controls under the rule, as well as the construction of new generating capacity (largely natural gas and solar PV). In 2025 and 2030, we estimate an increase of over 15,000 and 20,000 construction-related job-years, respectively, consistent with the projected increase in construction of new renewable and natural gas capacity in those years. Construction-related job-year changes are one-time impacts, occurring during each year of the multi-year periods during which construction of new capacity is completed. Construction-related figures in Table 6-6 represent a point estimate of incremental changes in construction jobs for each year (for a three-year construction projection, this table presents one-third of the total jobs for that project).

**Table 6-6. Changes in Labor Utilization: Construction-Related (Number of Job-Years of Employment in a Single Year)**

| | 2023 | 2025 | 2030 |
|---|---|---|---|
| New Pollution Controls | <100 | <100 | 2,800 |
| New Capacity | <100 | 15,400 | 20,500 |

Note: "<100" denotes an increase or decrease of less than 100 job-years

We also estimate changes in the number of job-years related to recurring non-construction employment. Recurring employment changes are job-years associated with annual recurring jobs including operating and maintenance activities and fuel extraction jobs. Newly built generating capacity creates a recurring stream of positive job-years, while retiring generating capacity, as well as avoided capacity builds, create a stream of negative job-years. The rule is projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity, which results in an overall decrease of non-construction jobs. The rule is also projected to result in a small increase in recurring employment related to fuel extraction. The total net estimated decrease in recurring employment is less than 4,000 job-years in 2030, which is a small percentage of total 2019 power sector employment reported in the 2020 USEER (approximately 900,000 generation-related jobs, 75,000 coal-related jobs, and 276,000 natural gas-related jobs). Note that the projected decreases related to operation of existing pollution controls is consistent with the projected retirements of existing capacity. Table 6-7 provide detailed estimates of recurring non-construction employment changes.

**Table 6-7. Changes in Labor Utilization: Recurring Non-Construction (Number of Job-Years of Employment in a Single Year)**

| | 2023 | 2025 | 2030 |
|---|---|---|---|
| Pollution Controls | <100 | <100 | <100 |
| Existing Capacity | <100 | -1,000 | -6,700 |
| New Capacity | <100 | 1,000 | 2,600 |
| Fuels (Coal, Natural Gas, Uranium) | <100 | <100 | 200 |
| *Coal* | *<100* | *<100* | *-200* |
| *Natural Gas* | *<100* | *<100* | *400* |
| *Uranium* | *<100* | *<100* | *<100* |

Note: "<100" denotes an increase or decrease of less than 100 job-years; Numbers may not sum due to rounding

*6.2.5 Non-EGU Labor Impacts*

This section begins with a description of baseline conditions in non-EGU industries affected by the rule, focusing on the directly regulated industries and groups of affected workers. Table 6-8 shows the industry definitions and the NAICS codes used to categorizes the data for the relevant industries. The cement and concrete product manufacturing industry (NAICS 3273) by far is the largest regulated industry in terms of the number of people employed. BLS Current Employment Statistics show that the industry employs 186,000 people nationally. The iron and steel mills and ferroalloy manufacturing industry (NAICS 3311) and glass and glass product manufacturing industry (NAICS 3772) are similarly sized with 81,400 and 79,900 people employed, respectively. Each of the non-EGU industries has seen different trends in employment over the past decade. Both the pipeline transportation of natural gas (NAICS 4862) and cement and concrete product manufacturing industries saw sizable increases in employment over the past decade, but cement and concrete product manufacturing contracted in 2020 from the COVID-19 pandemic. The iron and steel mills and ferroalloy manufacturing industry has seen steady decline in total employment, while the glass and glass product manufacturing industry has remained relatively constant over the last decade.[157]

**Table 6-8. Relevant Industry Employment (2020)**

| | NAICS | Employment (Thousands) | Percent Change 2011 - 2020 |
|---|---|---|---|
| Pipeline Transportation of Natural Gas | 4862 | 49.1 | 19% |
| Cement and Concrete Product Manufacturing | 3273 | 186.4 | 17% |
| Iron and Steel Mills and Ferroalloy Manufacturing | 3311 | 81.4 | -10% |
| Glass and Glass Product Manufacturing | 3772 | 79.9 | -1% |
| Basic Chemical Manufacturing | 3251 | 150.1 | 5% |
| Petroleum and Coal Products Manufacturing | 3241 | 106.5 | -5% |
| Pulp, Paper, and Paperboard Mills | 3221 | 92.6 | -15% |
| Waste Treatment and Disposal | 5622 | 101 | 4% |
| Metal Ore Mining | 2122 | 41.7 | 11% |

Source: BLS

These industries are capital intensive. We rely on two public sources to get a range of estimates of employment per output by sector: the Economic Census (EC), and the Annual Survey of Manufacturers (ASM), both provided by the U.S. Census Bureau. The EC is conducted every 5 years, most recently in 2017. The ASM is an annual subset of the EC and is based on a sample of establishments. The latest set of data from the ASM is from 2019. Both sets of U.S. Census Bureau data provide detailed industry data, providing estimates at the 4-digit NAICS level. They provide separate estimates of the number of employees and the value of shipments at the 4-digit NAICS, which we convert to a ratio in this employment analysis.

Table 6-9 provides estimates of employment per $1 million of products sold by the industry for each data source in 2017$. While the ratios are not the same, they are similar across time for both surveys. Glass and glass product manufacturing seems to be the most labor-intensive industry followed by waste treatment and disposal.

[157] Bureau of Labor Statistics. BLS Employment, Hours, and Earnings from the Current Employment Statistics survey (National), All-employees, May 2021

**Table 6-9. Employment per $1 million Output**

| Sector | Economic Census | ASM 2019 |
|---|---|---|
| Pipeline Transportation of Natural Gas | 1.21 | N/A |
| Cement and Concrete Product Manufacturing | 2.80 | 3.05 |
| Iron and Steel Mills and Ferroalloy Manufacturing | 0.97 | 0.91 |
| Glass and Glass Product Manufacturing | 3.34 | 3.35 |
| Basic Chemical Manufacturing | 0.68 | 0.75 |
| Petroleum and Coal Products Manufacturing | 0.20 | 0.18 |
| Pulp, Paper, and Paperboard Mills | 1.24 | 1.30 |
| Waste Treatment and Disposal | 3.25 | N/A |
| Metal Ore Mining | 1.33 | N/A |

### *6.2.6 Conclusions*

Generally, there are significant challenges when trying to evaluate the employment effects due to an environmental regulation from employment effects due to a wide variety of other economic changes, including the impact of the coronavirus pandemic on labor markets and the state of the macroeconomy generally. For EGUs, the Transport FIP for the 2015 ozone NAAQS may result in a sizable increase in construction-related jobs related to the installation of new pollution controls, as well as the construction of new generating capacity. The rule is also projected to result, generally, in a replacement of relatively labor-intensive coal capacity with less labor-intensive capacity, which results in an overall decrease of non-construction jobs. Speaking generally, a variety of federal programs are available to invest in communities potentially affected by coal mine and coal power plant closures. An initial report by The Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (April 2021) identifies funding available to invest in such "energy communities" through existing programs from agencies including Department of Energy, Department of Treasury, Department of Labor and others.[158] The Inflation Reduction Act also provides incentives to encourage investment in communities affected by coal mine and coal power plant closures.[159]

[158] See "Initial Report to the President on Empowering Workers Through Revitalizing Energy Communities" April 2021 at https://energycommunities.gov/wp-content/uploads/2021/11/Initial-Report-on-Energy-Communities_Apr2021.pdf

[159] For more details see Congressional Research Service. "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change" October 3, 2022 at https://crsreports.congress.gov/product/pdf/R/R47262

For the non-EGU industries, the employment trends over the last decade vary by industry. Without more detailed information on the labor required for installing pollution controls in these specific industries and other potential compliance approaches, we are not able to determine the potential effect of employment changes in the non-EGU industries.

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## CHAPTER 7: ENVIRONMENTAL JUSTICE IMPACTS

### 7.1 Introduction

Executive Order 12898 directs the EPA to "achiev[e] environmental justice (EJ) by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects" (59 FR 7629, February 16, 1994), termed disproportionate impacts in this chapter. Additionally, Executive Order 13985 was signed to advance racial equity and support underserved communities through Federal government actions (86 FR 7009, January 20, 2021). The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies".[160] Meaningful involvement means that: (1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; (2) the public's contribution can influence the regulatory Agency's decision; (3) the concerns of all participants involved will be considered in the decision-making process; and (4) the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected.

The term "disproportionate impacts" refers to differences in impacts or risks that are extensive enough that they may merit Agency action.[161] In general, the determination of whether a disproportionate impact exists is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision-maker. The terms "difference" or "differential" indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analyst to assess and present differences in anticipated impacts across population

[160] See, e.g., "Environmental Justice." *Epa.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, https://www.epa.gov/environmentaljustice.
[161] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

A regulatory action may involve potential EJ 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.

The Presidential Memorandum on Modernizing Regulatory Review (86 FR 7223; January 20, 2021) calls for procedures to "take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities." Under Executive Order 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,"[162] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. Baseline: Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.

[162] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

2. Policy: Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control), identifying how potential disparities change in response to the rulemaking.

The EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting EJ analyses, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

## 7.2 Analyzing EJ Impacts in This Final Rule

In addition to the benefits assessment (Chapter 5), the EPA considers potential EJ concerns associated with this final rulemaking. 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, 2015). For analytical 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, 2015). Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, the EPA's EJ Technical Guidance (U.S. EPA, 2015) states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

(1) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?

(2) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?

(3) For the regulatory option(s) under consideration, are potential EJ concerns created [, exacerbated,] or mitigated compared to the baseline?"

To address these questions, EPA developed an analytical approach that considers the purpose and specifics of the rulemaking, as well as the nature of known and potential exposures across various demographic groups. For example, while we recognize that the final rule is focused on reducing NOx emissions to implement obligations for 23 states under the “Good Neighbor” provision of the Clean Air Act to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states, this rulemaking may also reduce other pollutant emissions, such as nitrogen dioxide ($NO_2$).

Like other oxides of nitrogen, $NO_2$ can contribute to the formation of ozone and $PM_{2.5}$ downwind of sources; however, direct emissions of $NO_2$ can also lead to localized exposures that may be associated with respiratory effects in nearby populations at sufficiently high concentrations. In addition, people with asthma, children (especially ages 0−14 years), and older adults (especially ages 65 years and older) are identified as being at increased risk of $NO_2$-related health effects (U.S. EPA 2016). While $NO_2$ exposures and concentrations were not evaluated as part of this rule, proximity analyses of affected EGU and non-EGU facilities were performed as local exposures may be relevant to the baseline and/or change due to this action (Section 7.3).[163] In contrast, proximity analyses should not be used to interpret ozone and $PM_{2.5}$ exposure impacts due to this rulemaking, as ozone is secondarily formed and both pollutants can undergo long-range transport.

To directly assess EJ ozone and $PM_{2.5}$ exposure impacts, the EPA conducts an analysis of reductions in modeled ozone and $PM_{2.5}$ concentrations nationwide resulting from the NOx emissions reductions projected to occur under the rule, characterizing aggregated and distributional exposures both prior to and following implementation of the three regulatory alternatives in 2023 and 2026 (Section 7.4).

Unique limitations and uncertainties are specific to each type of analysis, which are described prior to presentation of analytic results in the subsections below.

## 7.3 Demographic Proximity Analyses

Demographic proximity analyses allow one to assess the potentially vulnerable populations residing nearby affected facilities as a proxy for exposure and the potential for adverse health impacts that may occur at a local scale due to economic activity at a given

[163] EPA is considering if and how to incorporate $NO_2$ health benefits into rulemakings. The ISA states that a key uncertainty in understanding the relationship between non-respiratory health effects and short- or long-term exposure to $NO_2$ is co-pollutant confounding, particularly by other traffic pollutants.

location including noise, odors, traffic, and emissions such as $NO_2$, covered under this EPA action and not modeled elsewhere in this RIA.

Although baseline proximity analyses are presented here, several important caveats should be noted. In most areas, emissions are not expected to increase from the rulemaking, so most communities nearby affected facilities should experience decreases in exposure from directly emitted pollutants. However, facilities may vary widely in terms of the impacts they already pose to nearby populations. In addition, proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur and should not be interpreted as a direct measure of exposure or impact. These points limit the usefulness of proximity analyses when attempting to answer question from EPA's EJ Technical Guidance.

Demographic proximity analyses were performed for two subsets of affected facilities:

- *Electricity Generating Unit (EGU)*: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living nearby covered EGU sources to average national levels.
- *Non-EGU (non-electric generating units, or other stationary emissions sources)*: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living nearby covered non-EGU sources to average national levels.

### *7.3.1 EGU Proximity Assessments*

The current analysis identified all census blocks with centroids within a 5 km, 10 km and 50 km radius of the latitude/longitude location of each facility, and then linked each block with census-based demographic data.[164] The total population within a specific radius around each facility is the sum of the population for every census block within that specified radius, based on

[164] Five km and 50 km radii are the default distances currently used for proximity analyses. The 5 km distance is the shortest distance that should be chosen to avoid excessive demographic uncertainty and provides information on near-field populations. The 50 km distance offers a sub-regional perspective. The 10 km distance was added to this analysis as few to no people were within 5 km of some affected facilities.

each block's population provided by the decennial Census.[165] Statistics on race, ethnicity, age, education level, poverty status and linguistic isolation were obtained from the Census' American Community Survey (ACS) 5-year averages for 2015-2019. These data are provided at the block group level. For the purposes of this analysis, the demographic characteristics of a given block group – that is, the percentage of people in different races/ethnicities, the percentage in different age groups (<18, 18-64, and >64), the percentage without a high school diploma, the percentage that are below the poverty level, and the percentage that are linguistically isolated – are presumed to also describe each census block located within that block group.

In addition to facility-specific demographics, the demographic composition of the total population within the specified radius (e.g., 50 km) for all facilities as a whole was also computed (e.g., all EGUs or all non-EGU facilities). In calculating the total populations, to avoid double-counting, each census block population was only counted once. That is, if a census block was located within the selected radius (i.e., 50 km) for multiple facilities, the population of that census block was only counted once in the total population. Finally, this analysis compares the demographics at each specified radius (i.e., 5 km, 10 km, and 50 km) to the demographic composition of the nationwide population.

For this action, a demographic analysis was conducted for 711 EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-1). Approximately 158 million people live within 50 km of the EGU facilities, representing roughly 48% of the 328 million total population of the U.S. The percent demographic make-up of the population within 50 km of the EGU facilities is very similar to the national average for each demographic investigated. Approximately 18.1 million and 48.1 million people live within 5 km and 10 km of the EGU facilities, respectively. The demographic make-up of the population within 5 km and 10 km of EGU facilities are very similar. Within 5 km and 10 km of EGU facilities, there is a higher Hispanic/Latino population (about 3 to 5% above national average) and a higher African American population (about 5 to 6% above national average). The age distribution for the population within 5 km and 10 km of EGU facilities is similar to the national average. The percent of people living below the poverty level is about 3% higher within 5 km and 10 km of the EGU facilities than the national average.

[165] The location of the Census block centroid is used to determine if the entire population of the Census block is assumed to be within the specified radius. It is unknown how sensitive these results may be to different methods of population estimation, such as aerial apportionment.

About 7% to 8% of the population within 5 km and 10 km of the EGU facilities is living in linguistic isolation, this is higher than the national average of 5%.

**Table 7-1. Population Demographics for EGU Facilities**

| Demographic Group | | Percent of Population Within Each Distance Compared to the National Average[1] | | | |
|---|---|---|---|---|---|
| | | **5km** | **10km** | **50km** | **National Average** |
| Race/ Ethnicity | White | 49.6% | 50.7% | 62.7% | 60.1% |
| | African American | 17.0% | 18.3% | 14.6% | 12.2% |
| | Native American | 0.4% | 0.4% | 0.4% | 0.7% |
| | Other and Multiracial | 9.3% | 8.6% | 7.1% | 8.2% |
| | Hispanic or Latino[2] | 23.7% | 21.9% | 15.2% | 18.8% |
| Age | 0-17 Years Old | 21.9% | 22.5% | 22.5% | 22.6% |
| | 18-64 Years Old | 63.9% | 62.9% | 61.9% | 61.7% |
| | >=65 Years Old | 14,2% | 14.6% | 15.6% | 15.7% |
| Income | People Living Below the Poverty Level | 16.8% | 15.9% | 13.2% | 13.4% |
| Education | >= 25 Years Old Without a High School Diploma | 15.2% | 14.3% | 11.7% | 12.1% |
| Language | People Living in Linguistic Isolation | 8.1% | 7.3% | 4.5% | 5.4% |
| **Total Population** | | **18,094,722** | **48,062,338** | **157,740,319** | **328,016,242** |

[1] Demographic percentage is based on the Census' 2015-2019 American Community Survey 5-year averages, at the block group level, and include the 50 states, District of Columbia, and Puerto Rico. Total population is based on block level data from the 2010 Decennial Census.

[2] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

### *7.3.2 Non-EGU Proximity Analysis*

For this action, a demographic analysis was also conducted for 482 non-EGU facilities at the 5 km, 10 km, and 50 km radius distances (Table 7-2). Approximately 130 million people live within 50 km of the non-EGU facilities, representing roughly 40% of the 328 million total population of the U.S. The percent demographic make-up of the population within 50 km of the non-EGU facilities is very similar to the national average for each demographic investigated. Approximately 5.7 million and 19.3 million people live within 5 km and 10 km of the non-EGU facilities, respectively. The demographic make-up of the population within 5 km and 10 km of non-EGU facilities are similar. Within 5 km and 10 km of non-EGU facilities, the African American population is 6% higher than the national average. The age distribution for the population within 5 km and 10 km of non-EGU facilities is similar to the national average. The percent of people living below the poverty level within 5 km and 10 km of the non-EGU facilities is about 2 to 4% higher than the national average. The percent of the population within 5 km and 10 km of the non-EGU facilities living in linguistic isolation is about the same as the national average (about 5%).

**Table 7-2. Population Demographics for Non-EGU Facilities**

| Demographic Group | | Percent of Population Within Each Distance Compared to the National Average[1] | | | |
|---|---|---|---|---|---|
| | | **5km** | **10km** | **50km** | **National Average** |
| Race/ Ethnicity | White | 55.6% | 56.8% | 59.0% | 60.1% |
| | African American | 18.2% | 18.2% | 14.1% | 12.2% |
| | Native American | 0.5% | 0.4% | 0.4% | 0.7% |
| | Other and Multiracial | 6.1% | 7.1% | 8.9% | 8.2% |
| | Hispanic or Latino[2] | 19.7% | 17.4% | 17.6% | 18.8% |
| Age | 0-17 Years Old | 22.9% | 22.2% | 22.1% | 22.6% |
| | 18-64 Years Old | 62.5% | 62.4% | 62.2% | 61.7% |
| | >=65 Years Old | 14.6% | 15.3% | 15.7% | 15.7% |
| Income | People Living Below the Poverty Level | 17.7% | 15.3% | 13.5% | 13.4% |
| Education | >= 25 Years Old Without a High School Diploma | 15.7% | 13.5% | 12.8% | 12.1% |
| Language | People Living in Linguistic Isolation | 5.4% | 4.8% | 5.4% | 5.4% |
| **Total Population** | | **5,743,473** | **19,284,115** | **130,446,759** | **328,016,242** |

[1] Demographic percentage is based on the Census' 2015-2019 American Community Survey 5-year averages, at the block group level, and include the 50 states, District of Columbia, and Puerto Rico. Total population is based on block level data from the 2010 Decennial Census.
[2] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

For additional information on the EGU or non-EGU proximity analyses, see the memorandum *Analysis of Demographic Factors For Populations Living Near EGU and Non-EGU Facilities*, in the rulemaking docket.

## 7.4 EJ Ozone and $PM_{2.5}$ Exposure Impacts

This EJ air pollutant exposure[166] analysis aims to evaluate the potential for EJ concerns related to $PM_{2.5}$ and ozone exposures[167] among potentially vulnerable populations. To assess EJ ozone and $PM_{2.5}$ exposure impacts, we focus on the first and third of the three EJ questions from the EPA's 2016 EJ Technical Guidance,[168] which ask if there are potential EJ concerns associated with stressors affected by the regulatory action for population groups of concern in the baseline and if those potential EJ concerns in the baseline are exacerbated, mitigated, or unchanged under the regulatory options being considered.[169]

To address these questions with respect to the air pollutants ozone and $PM_{2.5}$, the EPA developed an analytical approach that considers the purpose and specifics of this final rulemaking, as well as the nature of known and potential exposures and impacts. Specifically, as 1) this final rule affects EGUs across the U.S., which typically have tall stacks that result in emissions from these sources being dispersed over large distances, and 2) both as ozone and $PM_{2.5}$ can undergo long-range transport, it is appropriate to conduct an EJ assessment of the contiguous U.S. Given the availability of modeled baseline and policy $PM_{2.5}$ and ozone air quality surfaces, we conduct an analysis of changes in $PM_{2.5}$ and ozone concentrations resulting from the emission changes projected by the Integrated Planning Model (IPM) to occur under the final rule as compared to the baseline scenario, characterizing average and distributional exposures following implementation of the regulatory alternatives in 2023 and 2026. However, several important caveats of this analysis are as follows:

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[166] The term exposure is used here to describe estimated ozone and $PM_{2.5}$ concentrations and not individual dosage.
[167] Air quality surfaces used to estimate exposures are based on 12 km x 12 km grids. Additional information on air quality modeling can be found in the air quality modeling information section.
[168] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions. https://www.epa.gov/sites/default/files/2015-06/documents/considering-ej-in-rulemaking-guide-final.pdf
[169] EJ question 2, which asks if there are potential EJ concerns (i.e., disproportionate burdens across population groups) associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory options under consideration, was not focused on for several reasons. Importantly, the total magnitude of differential exposure burdens with respect to ozone and $PM_{2.5}$ among population groups at the national scale has been fairly consistent pre- and post-policy implementation across recent rulemakings. As such, differences in nationally aggregated exposure burden averages between population groups before and after the rulemaking tend to be very similar. Therefore, as disparities in pre- and post-policy burden results appear virtually indistinguishable, the difference attributable to the rulemaking can be more easily observed when viewing the change in exposure impacts, and as we had limited available time and resources, we chose to provide quantitative results on the pre-policy baseline and policy-specific impacts only, which related to EJ questions 1 and 3. We do however use the results from questions 1 and 3 to gain insight into the answer to EJ question 2 in the summary (Section 7.6).

- Modeling of post-policy air quality concentration changes are based on state-level emission data paired with facility-level baseline emissions. The air quality surfaces will capture expected air quality changes that result from state-to-state emissions change but will not capture heterogenous changes in emissions from multiple facilities within a single state.
- Air quality simulation input information are at a 12km x 12km grid resolution and population information is either at the Census tract- or county-level, potentially masking impacts at geographic scales more highly resolved than the input information.
- The two specific air pollutant metrics evaluated in this assessment, warm season maximum daily 8-hour ozone average concentrations and average annual $PM_{2.5}$ concentrations, are focused on longer-term exposures that have been linked to adverse health effects. This assessment does not evaluate disparities in other potentially health-relevant metrics, such as shorter-term exposures to ozone and $PM_{2.5}$.
- In the source apportionment modeling we aggregate emissions from point sources on all Tribal lands into a single nationwide source tag. Using a single nationwide Tribal tag will affect the spatial distribution pollutant impacts. In this respect, the NOx reductions at the Bonanza power plant in the 2026 final rule policy and more stringent alternatives impact pollutant concentrations in and around all Tribal lands. This is most evident in and around the Four Corners Generating Station in northwestern New Mexico where there are predicted pollutant reductions even though there are no controls applied to units at this facility.
- $PM_{2.5}$ EJ impacts were limited to exposures, and do not extend to health effects, given additional uncertainties associated with estimating health effects stratified by demographic population and the ability to predict differential $PM_{2.5}$-attributable EJ health impacts.
- Relative to the proposed rule, the final rule defers the backstop daily NOx emission rate from 2027 to no later than 2030 for those EGUs that do not have an SCR. In this analysis, we capture ozone and $PM_{2.5}$ exposure impacts in 2026 across the final, less stringent, and more stringent alternative for EGUs, but do not account for impacts of projected exposure changes in 2030 due to the backstop. However, given the IPM modeling in Chapter 4, we expect exposure reductions to be greater in 2030 for the final rule relative to the more stringent alternative.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, linguistic isolation, poverty status, age, and sex (Table 7-3).[170]

[170] Population projections stratified by race/ethnicity, age, and sex are based on economic forecasting models developed by Woods and Poole (Woods and Poole, 2015). The Woods and Poole database contains county-level projections of population by age, sex, and race out to 2050, relative to a baseline using the 2010 Census data.

**Table 7-3. Demographic Populations Included in the Ozone and $PM_{2.5}$ EJ Exposure Analyses**

| Demographic | Groups | Ages | Spatial Scale of Population Data |
|---|---|---|---|
| Race | Asian; American Indian; Black; White | 0-99 | Census tract |
| Ethnicity | Hispanic; Non-Hispanic | 0-99 | Census tract |
| Educational Attainment | High school degree or more; No high school degree | 25-99 | Census tract |
| Employment Status | Employed; Unemployed; Not in the labor force | 0-99 | County |
| Health Insurance | Insured; Uninsured | 0-64 | County |
| Linguistic Isolation | Speaks English "very well" or better; Speaks English less than "very well" OR<br>Speaks English "well" or better; Speaks English less than "well" | 0-99 | Census tract |
| Poverty Status | Above the poverty line; Below the poverty line OR<br>Above 2x the poverty line; Below 2x the poverty line | 0-99 | Census tract |
| Age | Children<br>Adults<br>Older Adults | 0-17<br>18-64<br>65-99 | Census tract |
| Sex | Female; Male | 0-99 | Census tract |

### *7.4.1 Ozone Exposure Analysis*

To evaluate the potential for EJ concerns among potentially vulnerable populations resulting from exposure to ozone under the baseline and regulatory control alternatives in this rule, we assess the impact of NOx emissions reductions on downwind ozone concentrations. EPA presents an analysis of ozone concentrations associated with upwind NOx emissions, characterizing the distribution of exposures both prior to and following implementation of the final rule, as well as of the more and less stringent regulatory alternatives, in 2023 and 2026. Under the final rule and more stringent regulatory alternative, the year of full compliance is 2026 for both EGUs and non-EGUs, except for the EGU backstop emission rate on coal units greater than 100 MW within the 19-state region that lack SCR controls, which occurs in 2030 in the final rule (emissions budgets in 2026 are commensurate with a backstop rate in place). Under the less stringent scenario the year of full compliance is 2030 for EGUs and 2026 for non-EGUs.[171]

Population projections for each county are determined simultaneously with every other county in the U.S to consider patterns of economic growth and migration. County-level estimates of population percentages within the poverty status and educational attainment groups were derived from 2015-2019 5-year average ACS estimates. Additional information can be found in Appendix J of the BenMAP-CE User's Manual (https://www.epa.gov/benmap/benmap-ce-manual-and-appendices).

[171] We did not evaluate or bring in stratified baseline incidence rates or concentration-response functions relating to potentially evaluating at-risk populations. As results of a risk analysis lacking stratified concentration-response

As this analysis is based on the same ozone spatial fields as the benefits assessment (see Chapter 3 for a discussion of the spatial fields), it is subject to similar types of uncertainty (see Chapter 5, Section 5.1.3 for a discussion of the uncertainty). A particularly germane limitation is that ozone, being a secondary pollutant, is the byproduct of complex atmospheric chemistry such that direct linkages cannot be made between specific affected facilities and downwind ozone concentration changes based on available air quality modeling (see Chapter 3, Section 3.4).

Ozone concentration and exposure metrics can take many forms, although only a small number are commonly used. The analysis presented here is based on the average April-September warm season maximum daily 8-hour average ozone concentrations (AS-MO3), consistent with the health impact functions used in the benefits assessment (Chapter 5). As developing spatial fields is time and resource intensive, the same spatial fields used for the benefits analysis were also used for the ozone exposure analysis performed here to assess EJ impacts.

The construct of the AS-MO3 ozone metric used for this analysis should be kept in mind when attempting to relate the results presented here to the ozone NAAQS and when interpreting the confidence in the association between exposures and health effects. Specifically, the seasonal average ozone metric used in this analysis is not constructed in a way that directly relates to NAAQS design values, which are based on daily maximum 8-hour concentrations.[172] Thus, AS-MO3 values reflecting seasonal *average* concentrations well below the level of the NAAQS at a particular location do not necessarily indicate that the location does not experience any *daily* (8-hour) exceedances of the ozone NAAQS. Relatedly, the EPA is confident that reducing the highest ambient ozone concentrations will result in substantial improvements in public health, including reducing the risk of ozone-associated mortality. However, the Agency is less certain about the public health implications of changes in relatively low ambient ozone concentrations. Most health studies rely on a metric such as the warm-season average ozone concentration; as a result, the EPA typically utilizes air quality inputs such as the AS-MO3 spatial fields in the benefits assessment, and we judge them also to be the best available air quality inputs for this EJ

and/or baseline incidence rates would not provide additional information regarding population group impacts beyond exposure differences and age-related difference in baseline incidence, this EJ analysis was limited to exposure only.

[172] Level of 70 ppb with an annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years.

ozone exposure assessment. To further support the use of the AS-MO3 spatial fields in this ozone analysis, we compared baseline AS-MO3 spatial fields with average baseline maximum daily 1-hour average (MDA1) ozone concentrations spatial fields in the proposal for this rulemaking, also over the April-September warm season, and found that average population ozone concentration trends within populations were similar when considering either the AS-MO3 or the MDA1 spatial fields. Therefore, in this final rulemaking, we performed ozone analyses using only the AS-MO3 metric over the April-September warm season.

The metric and averaging season are also relevant inputs to consider when interpreting the results as they can affect the sharpness of pollutant gradients, an important factor when associating exposure for different demographic populations. Figure 3-2 and Figure  in Chapter 3 of this RIA show maps of the baseline 12 km gridded AS-MO3 concentrations in 2023 and 2026, respectively. As the AS-MO3 seasonal metric is based on the average of concentrations over more than 180 days in the spring and summer, the resulting spatial fields are relatively smooth and do not display sharp gradients, compared to what might be expected when looking at the spatial patterns of the average maximum daily 8-hour average ozone concentrations on individual high ozone episode days.

The ozone exposure analyses begin with heat maps of national- and state-level aggregated results (Section 7.4.1.1) and then examine spatially resolved distributional results via figures (Section 7.4.1.3).

##### *7.4.1.1 Aggregated Results*

Results aggregated to the national and state levels provide an overview of the average impacts within each population group. We provide baseline results in absolute terms (i.e., total AS-MO3 concentrations) and regulatory alternative results in relative terms (i.e., the change in AS-MO3 concentrations).

As inclusion of additional "on the books" regulations could impact the pre-policy scenario, it is important to begin by evaluating the baseline, or pre-regulatory, conditions. Average baseline AS-MO3 concentrations in parts per billion (ppb) in the two modeled future years, 2023 and 2026, are shown in the colored columns of the below heat maps (Figure 7-1 and Figure 7-2). Concentrations in the "baseline" column represent the total estimated ozone exposure burden averaged over the 6-month warm season each year and are colored to more easily visualize differences in average concentrations, with lighter green coloring representing lower average concentrations and darker green coloring representing higher average concentrations.

Average ozone concentrations are estimated to increase slightly across the overall reference population (top row) between 2023 and 2026 by approximately 0.5 ppb. While many of the average ozone concentrations within the individual population groups are estimated to be similar to or below average concentrations of the overall reference group (i.e., the total population of contiguous U.S.), certain populations are estimated to experience higher average ozone concentrations in the baseline in both future years. Populations with national average ozone concentrations higher than the reference population in both 2023 and 2026 ordered from most to least difference were: American Indians, Hispanics, linguistically isolated, Asians, the less educated, and children. These populations live in areas with seasonal average baseline ozone concentrations of up to 2.1 ppb higher than the national average concentrations.[173] In contrast, national average baseline ozone concentrations in the Black population are estimated to be about 1.2 ppb less than the reference group in both 2023 and 2026. However, it is important to note that these are aggregate results across broad areas and large numbers of people, which may underestimate the impact in individual locations where there is both an ozone nonattainment issue and a disproportionately large racial/ethnic population. Additionally, while average AS-MO3 exposures across all groups are relatively low (~40-43 ppb), these seasonal estimates do not necessarily indicate that individual locations do not experience exceedances of the NAAQS. Thus, it is difficult to draw conclusions from this analysis about whether some population subgroups experience hyperlocal higher daily maximum exposures than others in the baseline.

Overall, the national-level baseline assessment of ozone concentrations suggests that there may be potential EJ exposure concerns for certain population groups of concern in the baseline. Specifically, the data indicate that some population subgroups evaluated may experience slightly elevated seasonal average ozone concentrations in the baseline as compared to the reference group nationally.

[173] Differences in both 2023 and 2026 were calculated and averaged to generate these estimates, as differences between the air quality in the two future years were similar.

The right sides of Figure 7-1 and Figure 7-2 provide information regarding how the final rulemaking will impact ozone concentrations across various populations.[174] Figure 7-3 shows how ozone concentrations may change in 2023 (from EGU controls only) and in 2026 (from EGUs controls, non-EGU controls, and EGU and non-EGU controls combined) under the rule, the less stringent alternative, and the more stringent alternative. Under the final rule, the population-weighted seasonal average ozone reduction in the overall reference group is approximately 0.03 ppb in 2023 and 0.3 ppb in 2026. The relative population-weighted AS-MO3 ozone concentration reduction contributions from EGUs and non-EGUs can be directly compared in 2026. 0.1 ppb of ozone concentration reductions are attributable to affected EGUs and 0.2 ppb are attributable to non-EGU affected facilities. Hispanics, Asians, American Indians, and linguistically isolated populations are estimated to experience reductions in AS-MO3 that are slightly less than the reference group in both 2023 and 2026. Pairing these results with the national baseline ozone concentrations suggests that although this rule lessens overall ozone concentrations within each population as compared with the baseline levels, reductions are smallest in populations with higher baseline ozone concentrations. However, the relative differences in the policy impacts are small (e.g., on the order of ~0.1 ppb less reduction in ozone among these subpopulations as compared to the reference group) and substantially smaller than the baseline differences across these subpopulations (~2 ppb). Conversely, Black and non-Hispanic individuals, who on average experience lower ozone concentrations than the reference group under the baseline, are estimated to experience average ozone concentration reductions slightly greater than the reference group in 2023 and 2026. Again, these differences are small relative to the overall reduction in ozone concentrations across all populations.[175]

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[174] The final rule and less stringent scenario defer the backstop emission rate for certain EGUs until the 2030 run year, while the more stringent alternative imposes the backstop emission rate in the 2025 run year. Retirements that may be undertaken by EGU source owners/operators as a least-cost compliance strategy are therefore delayed in the final rule and less stringent alternative relative to the more stringent alternative. Since the power sector model is forward looking, it has an incentive to run units harder before they retire. This incentive is lower in the final rule and less stringent alternative relative to the more stringent alternative due to delayed retirements. As such, emissions are slightly lower in 2023 in some states in the less stringent alternative and final rule relative to the more stringent alternative, leading to slightly greater emissions reductions.

[175] We report average exposure results to the decimal place where difference between demographic populations become visible, as we cannot provide a quantitative estimate of the air quality modeling precision uncertainty. Using this approach allows for a qualitative consideration of uncertainties and the significance of the relatively small differences.

Under the less stringent regulatory alternative in 2023 there are similar magnitudes of ozone concentration reductions in the reference group as in the rule, and a greater reduction in average ozone concentration in the more stringent regulatory alternative, within all population groups. In 2026 the less stringent and more stringent alternatives are estimated to result in smaller and larger reductions in ozone concentrations, respectively, as compared to the final rule. Notably, the less stringent alternative has smaller ozone concentration reductions from EGUs than from non-EGUs, whereas the more stringent alternative has slightly larger ozone concentration reductions from both EGUs and non-EGUs.

The national-level assessment of ozone before and after implementation of this final rulemaking suggests that while EJ exposure disparities are present in the pre-policy scenario, meaningful EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated. In other words, the data indicate that all population subgroups evaluated may experience similar seasonal average ozone concentration changes after implementation of this rule as compared to the reference group nationally.

| Population | Group | Population Count | 2023<br>-<br>Baseline | EGU<br>Final | Less | More |
|---|---|---|---|---|---|---|
| Reference | Reference (0-99) | 343M | 41.30 | 0.03 | 0.03 | 0.03 |
| Race | White (0-99) | 270M | 41.39 | 0.03 | 0.03 | 0.03 |
| | American Indian (0-99) | 4M | 43.41 | 0.04 | 0.04 | 0.04 |
| | Asian (0-99) | 22M | 42.44 | 0.02 | 0.02 | 0.02 |
| | Black (0-99) | 47M | 40.13 | 0.03 | 0.03 | 0.04 |
| Ethnicity | Non-Hispanic (0-99) | 275M | 40.83 | 0.03 | 0.03 | 0.04 |
| | Hispanic (0-99) | 68M | 43.22 | 0.02 | 0.02 | 0.02 |
| Linguistic Isolation | English "well or better" (0-99) | 327M | 41.24 | 0.03 | 0.03 | 0.03 |
| | English < "well" (0-99) | 16M | 42.55 | 0.02 | 0.02 | 0.02 |
| Poverty Status | <Poverty line (0-99) | 54M | 41.31 | 0.03 | 0.03 | 0.03 |
| | >Poverty line (0-99) | 288M | 41.30 | 0.03 | 0.03 | 0.03 |
| Educational Attainment | More educated (>24: HS or more) | 201M | 41.13 | 0.03 | 0.03 | 0.03 |
| | Less educated (>24; no HS) | 33M | 41.70 | 0.03 | 0.03 | 0.03 |
| Employment Status | Employed (0-99) | 9M | 41.71 | 0.03 | 0.03 | 0.03 |
| | Unemployed (0-99) | 343M | 41.30 | 0.03 | 0.03 | 0.03 |
| | Not in the labor force (0-99) | 174M | 41.27 | 0.03 | 0.03 | 0.03 |
| Insurance Status | Insured (0-64) | 251M | 41.44 | 0.03 | 0.03 | 0.03 |
| | Unisured (0-64) | 30M | 41.00 | 0.03 | 0.03 | 0.03 |
| Age | Children (0-17) | 78M | 41.54 | 0.03 | 0.03 | 0.03 |
| | Adults (18-64) | 204M | 41.34 | 0.03 | 0.03 | 0.03 |
| | Older Adults (65-99) | 61M | 40.89 | 0.03 | 0.03 | 0.03 |
| Sex | Females (0-99) | 174M | 41.29 | 0.03 | 0.03 | 0.03 |
| | Males (0-99) | 169M | 41.31 | 0.03 | 0.03 | 0.03 |

**Figure 7-1. Heat Map of the National Average AS-MO3 Ozone Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2023 (ppb)**

| Population | Group | Population Count | 2026<br>Baseline<br>- | Final<br>EGU | NonEGU | EGU+NonEGU | Less<br>EGU | NonEGU | EGU+NonEGU | More<br>EGU | NonEGU | EGU+NonEGU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Reference | Reference (0-99) | 352M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Race | White (0-99) | 276M | 41.9 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.6 |
| | American Indian (0-99) | 4M | 43.9 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.5 |
| | Asian (0-99) | 24M | 42.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.1 | 0.3 | 0.5 |
| | Black (0-99) | 49M | 40.6 | 0.1 | 0.3 | 0.4 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Ethnicity | Non-Hispanic (0-99) | 279M | 41.3 | 0.1 | 0.2 | 0.4 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Hispanic (0-99) | 73M | 43.6 | 0.1 | 0.2 | 0.2 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.5 |
| Linguistic Isolation | English "well or better" (0-99) | 336M | 41.7 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | English < "well" (0-99) | 16M | 42.9 | 0.1 | 0.2 | 0.2 | 0.0 | 0.1 | 0.1 | 0.1 | 0.3 | 0.5 |
| Poverty Status | <Poverty line (0-99) | 55M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | >Poverty line (0-99) | 296M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Educational Attainment | More educated (>24: HS or more) | 207M | 41.6 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.6 |
| | Less educated (>24; no HS) | 34M | 42.2 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Employment Status | Employed (0-99) | 9M | 42.2 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Unemployed (0-99) | 352M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Not in the labor force (0-99) | 179M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Insurance Status | Insured (0-64) | 255M | 41.9 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Unisured (0-64) | 31M | 41.5 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| Age | Children (0-17) | 80M | 42.0 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Adults (18-64) | 206M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Older Adults (65-99) | 67M | 41.4 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.5 |
| Sex | Females (0-99) | 178M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |
| | Males (0-99) | 174M | 41.8 | 0.1 | 0.2 | 0.3 | 0.0 | 0.1 | 0.1 | 0.2 | 0.4 | 0.6 |

**Figure 7-2. Heat Map of the National Average AS-MO3 Ozone Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2026 (ppb)**

#### 7.4.1.2 State Aggregated Results

The goal of this action is to require NOx emissions reductions that will eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind areas.[176] As upwind emissions reductions necessary to achieve this goal will not affect ozone concentrations uniformly within each state, we provide AS-MO3 ozone concentration changes by state and demographic population for the two future years (Figure 7-3 and Figure 7-4). Figure 7-3 shows the EGU impacts in 2023 and Figure 7-4 shows the combined EGU and non-EGU impacts in 2026 for the 48 states in the contiguous U.S, for the policy scenario only. In these heat maps darker green indicates larger AS-MO3 reductions and red colors show AS-MO3 increases, although the demographic groups are now shown as columns and each state as a row. On average, the state-specific reference populations are projected to experience reductions in AS-MO3 concentrations by up to 0.16 ppb in Missouri in 2023 and 1.2 ppb in Arkansas in 2026. In 2023 there are also predicted to be AS-MO3 increases up to 0.06 ppb in West Virginia; these increases are very small, however, and by 2026, West Virginia is projected to experience substantially greater reductions in AS-MO3 concentrations, on the order of 0.8 ppb. In most states, populations potentially of concern are projected to experience similar AS-MO3 concentration changes as the state-level reference population.

An important limitation of this state-level analysis is that the influence of the number of people in the state is not reflected in the results, whereas the national-level results above weight air quality changes by population. For example, even though there is only a small reduction in AS-MO3 concentration from this action in California, the state's large population will contribute substantially to the national averages. Conversely, while the largest AS-MO3 concentration reductions in 2026 occur in Arkansas and Louisiana, as of 2022, they are the 34th and 25th most populated states, respectively, and will contribute less to the national population-weighted AS-MO3 information than more populated states, such as California.

Therefore, whereas ozone exposure impacts vary considerably across states, the small magnitude of differential impacts expected by the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns within individual states.

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[176] See Section 1 of the rule preamble for a discussion of the states included in the rule and their requirements for EGUs and non-EGUs.

2023

EGU

| State | Refe.. | Race | | | | Ethnicity | | Linguistic Isolation | | Poverty Status | | Educational Attainment | | Employment Status | | | Insurance Status | | Age | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference (0-99) | White (0-99) | American Indian (0-99) | Asian (0-99) | Black (0-99) | Non-Hispanic (0-99) | Hispanic (0-99) | English "well or better" (0-99) | English < "well" (0-99) | <Poverty line (0-99) | >Poverty line (0-99) | More educated (>24: HS or more) | Less educated (>24; no HS) | Employed (0-99) | Unemployed (0-99) | Not in the labor force (0-99) | Insured (0-64) | Unisured (0-64) | Children (0-17) | Adults (18-64) | Older Adults (65-99) |
| Alabama | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Arizona | 0.01 | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Arkansas | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| California | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Colorado | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Connecticut | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Delaware | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Florida | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Georgia | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Idaho | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Illinois | 0.07 | 0.07 | 0.07 | 0.06 | 0.07 | 0.08 | 0.06 | 0.07 | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Indiana | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Iowa | 0.07 | 0.07 | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Kansas | 0.09 | 0.09 | 0.10 | 0.09 | 0.09 | 0.09 | 0.08 | 0.09 | 0.08 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Kentucky | 0.08 | 0.08 | 0.08 | 0.08 | 0.09 | 0.08 | 0.08 | 0.08 | 0.09 | 0.07 | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 | 0.07 | 0.08 | 0.07 | 0.08 | 0.08 | 0.08 |
| Louisiana | 0.06 | 0.06 | 0.06 | 0.07 | 0.06 | 0.06 | 0.07 | 0.06 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Maine | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Maryland | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Massachusetts | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Michigan | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Minnesota | 0.08 | 0.08 | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 | 0.07 | 0.07 | 0.08 | 0.07 | 0.08 | 0.07 | 0.08 | 0.08 | 0.07 |
| Mississippi | 0.10 | 0.10 | 0.09 | 0.13 | 0.08 | 0.10 | 0.11 | 0.10 | 0.10 | 0.09 | 0.10 | 0.10 | 0.09 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.09 |
| Missouri | 0.14 | 0.14 | 0.12 | 0.16 | 0.15 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.14 |
| Montana | 0.01 | 0.01 | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 |
| Nebraska | 0.05 | 0.05 | 0.04 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 | 0.05 | 0.05 | 0.04 |
| Nevada | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.05 |
| New Hampshire | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| New Jersey | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| New Mexico | 0.03 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 |
| New York | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| North Carolina | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| North Dakota | 0.01 | 0.01 | 0.01 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Ohio | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.04 | 0.03 | 0.03 |
| Oklahoma | 0.14 | 0.14 | 0.13 | 0.15 | 0.14 | 0.14 | 0.14 | 0.14 | 0.15 | 0.14 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 |
| Oregon | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Pennsylvania | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Rhode Island | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| South Carolina | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| South Dakota | 0.03 | 0.03 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Tennessee | 0.06 | 0.05 | 0.06 | 0.06 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.05 |
| Texas | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 | 0.05 | 0.04 | 0.04 | 0.05 | 0.05 | 0.04 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 | 0.05 | 0.05 | 0.05 |
| Utah | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Vermont | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Virginia | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Washington | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| West Virginia | -0.04 | -0.04 | -0.04 | -0.06 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 | -0.04 |
| Wisconsin | 0.07 | 0.07 | 0.06 | 0.07 | 0.08 | 0.07 | 0.08 | 0.07 | 0.08 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Wyoming | 0.03 | 0.03 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 |

**Figure 7-3. Heat Map of State Average AS-MO3 Ozone Concentration Reductions (Green) and Increases (Red) by Demographic Group for EGUs in 2023 (ppb)**

| | 2026 EGU+NonEGU | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref.. | Race | | | | Ethnicity | | Linguistic Isolation | | Poverty Status | | Educational Attainment | | Employment Status | | | Insurance Status | | Age | | |
| State | Reference (0-99) | White (0-99) | American Indian (0-99) | Asian (0-99) | Black (0-99) | Non-Hispanic (0-99) | Hispanic (0-99) | English "well or better" (0-99) | English < "well" (0-99) | <Poverty line (0-99) | >Poverty line (0-99) | More educated (>24: HS or more) | Less educated (>24; no HS) | Employed (0-99) | Unemployed (0-99) | Not in the labor force (0-99) | Insured (0-64) | Unisured (0-64) | Children (0-17) | Adults (18-64) | Older Adults (65-99) |
| Alabama | 0.36 | 0.37 | 0.38 | 0.36 | 0.35 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Arizona | 0.09 | 0.09 | 0.11 | 0.09 | 0.09 | 0.10 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Arkansas | 1.02 | 0.99 | 0.89 | 0.92 | 1.20 | 1.03 | 0.91 | 1.02 | 0.92 | 1.03 | 1.02 | 1.03 | 1.00 | 1.04 | 1.02 | 1.02 | 1.03 | 0.98 | 1.02 | 1.02 | 1.02 |
| California | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.10 | 0.12 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 |
| Colorado | 0.15 | 0.15 | 0.16 | 0.15 | 0.15 | 0.16 | 0.15 | 0.15 | 0.15 | 0.16 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.16 | 0.15 | 0.15 | 0.16 |
| Connecticut | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 |
| Delaware | 0.35 | 0.35 | 0.35 | 0.36 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 |
| Florida | 0.07 | 0.07 | 0.08 | 0.07 | 0.07 | 0.08 | 0.05 | 0.07 | 0.05 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Georgia | 0.24 | 0.25 | 0.25 | 0.26 | 0.23 | 0.24 | 0.25 | 0.24 | 0.26 | 0.23 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 |
| Idaho | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Illinois | 0.55 | 0.55 | 0.52 | 0.50 | 0.56 | 0.56 | 0.50 | 0.55 | 0.49 | 0.56 | 0.55 | 0.55 | 0.54 | 0.54 | 0.55 | 0.55 | 0.55 | 0.53 | 0.55 | 0.55 | 0.56 |
| Indiana | 0.64 | 0.64 | 0.62 | 0.63 | 0.61 | 0.64 | 0.60 | 0.64 | 0.60 | 0.63 | 0.64 | 0.64 | 0.63 | 0.63 | 0.64 | 0.63 | 0.64 | 0.63 | 0.63 | 0.64 | 0.64 |
| Iowa | 0.36 | 0.36 | 0.34 | 0.37 | 0.38 | 0.37 | 0.35 | 0.36 | 0.35 | 0.37 | 0.36 | 0.36 | 0.36 | 0.37 | 0.36 | 0.37 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Kansas | 0.53 | 0.53 | 0.58 | 0.54 | 0.55 | 0.54 | 0.51 | 0.53 | 0.50 | 0.54 | 0.53 | 0.54 | 0.53 | 0.55 | 0.53 | 0.54 | 0.53 | 0.53 | 0.53 | 0.53 | 0.53 |
| Kentucky | 0.83 | 0.82 | 0.84 | 0.86 | 0.89 | 0.83 | 0.85 | 0.83 | 0.87 | 0.80 | 0.84 | 0.84 | 0.80 | 0.83 | 0.83 | 0.82 | 0.83 | 0.81 | 0.83 | 0.83 | 0.83 |
| Louisiana | 1.02 | 1.02 | 0.90 | 1.03 | 1.04 | 1.02 | 1.03 | 1.02 | 1.02 | 1.01 | 1.03 | 1.03 | 1.00 | 1.03 | 1.02 | 1.02 | 1.03 | 1.01 | 1.02 | 1.03 | 1.02 |
| Maine | 0.09 | 0.09 | 0.08 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Maryland | 0.41 | 0.42 | 0.41 | 0.42 | 0.40 | 0.42 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.42 | 0.41 | 0.41 | 0.41 | 0.42 | 0.41 | 0.41 | 0.41 | 0.41 | 0.42 |
| Massachusetts | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.16 |
| Michigan | 0.47 | 0.47 | 0.42 | 0.48 | 0.49 | 0.47 | 0.49 | 0.47 | 0.49 | 0.48 | 0.47 | 0.47 | 0.48 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 |
| Minnesota | 0.22 | 0.22 | 0.17 | 0.23 | 0.23 | 0.22 | 0.23 | 0.22 | 0.23 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 |
| Mississippi | 0.70 | 0.69 | 0.64 | 0.68 | 0.71 | 0.70 | 0.69 | 0.70 | 0.71 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 |
| Missouri | 0.81 | 0.80 | 0.73 | 0.88 | 0.87 | 0.81 | 0.73 | 0.81 | 0.78 | 0.78 | 0.81 | 0.81 | 0.80 | 0.81 | 0.81 | 0.80 | 0.81 | 0.78 | 0.80 | 0.81 | 0.81 |
| Montana | 0.02 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Nebraska | 0.26 | 0.26 | 0.24 | 0.28 | 0.28 | 0.26 | 0.26 | 0.26 | 0.27 | 0.27 | 0.26 | 0.26 | 0.26 | 0.27 | 0.26 | 0.26 | 0.27 | 0.26 | 0.26 | 0.27 | 0.26 |
| Nevada | 0.09 | 0.08 | 0.07 | 0.09 | 0.09 | 0.08 | 0.09 | 0.08 | 0.09 | 0.09 | 0.08 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 | 0.09 | 0.08 |
| New Hampshire | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 |
| New Jersey | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.29 | 0.30 | 0.29 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 |
| New Mexico | 0.17 | 0.16 | 0.24 | 0.16 | 0.16 | 0.18 | 0.16 | 0.17 | 0.15 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.18 | 0.17 | 0.17 | 0.17 |
| New York | 0.27 | 0.27 | 0.27 | 0.26 | 0.26 | 0.27 | 0.26 | 0.27 | 0.25 | 0.27 | 0.27 | 0.27 | 0.26 | 0.27 | 0.27 | 0.27 | 0.27 | 0.26 | 0.27 | 0.27 | 0.27 |
| North Carolina | 0.28 | 0.28 | 0.25 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 |
| North Dakota | 0.06 | 0.06 | 0.04 | 0.07 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.05 | 0.05 | 0.06 | 0.05 | 0.06 | 0.05 | 0.05 | 0.06 | 0.05 |
| Ohio | 0.69 | 0.69 | 0.69 | 0.70 | 0.68 | 0.69 | 0.66 | 0.69 | 0.67 | 0.69 | 0.69 | 0.69 | 0.69 | 0.68 | 0.69 | 0.69 | 0.69 | 0.69 | 0.69 | 0.69 | 0.68 |
| Oklahoma | 0.89 | 0.88 | 0.90 | 0.92 | 0.92 | 0.89 | 0.89 | 0.89 | 0.91 | 0.89 | 0.89 | 0.89 | 0.88 | 0.90 | 0.89 | 0.89 | 0.89 | 0.88 | 0.89 | 0.89 | 0.88 |
| Oregon | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Pennsylvania | 0.46 | 0.46 | 0.42 | 0.42 | 0.42 | 0.46 | 0.40 | 0.46 | 0.40 | 0.45 | 0.46 | 0.46 | 0.44 | 0.46 | 0.46 | 0.46 | 0.45 | 0.48 | 0.45 | 0.45 | 0.46 |
| Rhode Island | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 | 0.17 |
| South Carolina | 0.20 | 0.20 | 0.20 | 0.20 | 0.19 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| South Dakota | 0.14 | 0.14 | 0.10 | 0.15 | 0.16 | 0.14 | 0.14 | 0.14 | 0.17 | 0.13 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.13 | 0.14 | 0.14 | 0.13 |
| Tennessee | 0.52 | 0.50 | 0.52 | 0.54 | 0.62 | 0.52 | 0.54 | 0.52 | 0.53 | 0.54 | 0.52 | 0.52 | 0.52 | 0.53 | 0.52 | 0.52 | 0.53 | 0.53 | 0.53 | 0.52 | 0.51 |
| Texas | 0.44 | 0.43 | 0.45 | 0.48 | 0.50 | 0.48 | 0.38 | 0.44 | 0.40 | 0.41 | 0.44 | 0.45 | 0.42 | 0.44 | 0.44 | 0.43 | 0.44 | 0.42 | 0.43 | 0.44 | 0.44 |
| Utah | 0.28 | 0.28 | 0.28 | 0.29 | 0.29 | 0.28 | 0.29 | 0.28 | 0.29 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.27 |
| Vermont | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Virginia | 0.44 | 0.44 | 0.43 | 0.43 | 0.41 | 0.44 | 0.43 | 0.44 | 0.43 | 0.44 | 0.43 | 0.44 | 0.44 | 0.43 | 0.44 | 0.44 | 0.43 | 0.44 | 0.43 | 0.43 | 0.44 |
| Washington | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| West Virginia | 0.83 | 0.84 | 0.83 | 0.85 | 0.80 | 0.84 | 0.77 | 0.83 | 0.76 | 0.84 | 0.83 | 0.83 | 0.82 | 0.84 | 0.83 | 0.83 | 0.84 | 0.82 | 0.83 | 0.83 | 0.83 |
| Wisconsin | 0.31 | 0.31 | 0.27 | 0.31 | 0.35 | 0.31 | 0.34 | 0.31 | 0.33 | 0.32 | 0.31 | 0.31 | 0.32 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Wyoming | 0.08 | 0.08 | 0.07 | 0.09 | 0.10 | 0.08 | 0.09 | 0.08 | 0.08 | 0.09 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |

**Figure 7-4. Heat Map of State Average AS-MO3 Ozone Concentration Reductions by Demographic Group for EGUs and Non-EGUs in 2026 (ppb)**

#### *7.4.1.3 Distributional Results*

While aggregated national- and state-level average ozone concentration results (Section 7.4.1.1) provide an overview of potential exposure differences across populations, detailed information on the distribution of AS-MO3 ozone exposures within populations, and specifically the portions of each population experiencing ozone concentration changes due to the rule, can provide a more comprehensive understanding of analytical results. Figures in this section present cumulative counts of each population exposed to ascending levels of AS-MO3 ozone concentrations across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanics) in the contiguous U.S. experience average baseline ozone concentrations at or below certain AS-MO3 ozone concentrations (e.g., 40 ppb) compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences ozone concentrations. More specifically, to permit the direct comparison of demographic populations with different absolute numbers (e.g., the large overall reference population with the much smaller number of Asians), we plot the running sum of each population as a percentage against the ozone concentration changes from NOx emissions reductions under the regulatory alternatives.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions (U.S. EPA 2021d, Section 6). For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations expected to experience post-policy AS-MO3 exposure changes. We also did not evaluate whether concentration reductions/increases occurred in areas of higher/lower baseline burden exposures. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to conclusively assert that there are meaningful differences in ozone exposure impacts in either the baseline or the rule across population groups.

As the baseline scenario is similar to that of the rule, we focus on the policy-specific ozone changes of this final rulemaking.[177] Distributions of 12 km gridded ozone concentration

[177] Briefly, the rule concluded that approximately 80% of the overall reference population resides in areas of AS-MO3 ozone concentrations at or less than about 45 ppb in 2023 and 2026. Most of this population experiences AS-

reductions from NOx emissions reductions of affected facilities under the three regulatory alternatives analyzed in this final rulemaking in 2023 (EGU controls only) and 2026 (EGU and non-EGU controls, combined) are shown in Figure 7-5 and Figure 7-6, respectively. For clarity, only above/below the poverty line and those who speak English “well or better”/“less than well” are shown and sex and the overall reference group are excluded from the cumulative distribution figures.

The vast majority of ozone concentration changes are less than 0.1 ppb in 2023 and less than 1 ppb in 2026. As was observed in the national average ozone concentration analysis (Section 7.4.1.1), there are slight differences in the ozone concentration changes across population demographics and regulatory alternatives in 2023 and 2026 (Figure 7-5 and Figure 7-6, respectively). Proportionally, Hispanics, Asians, American Indians, and those linguistically isolated populations experience smaller ozone concentration reductions under the regulatory alternatives than the overall reference population in 2023, by a very small amount. Alternatively, the distribution of ozone concentration reductions for Black populations is greater than the reference population only in the smallest half of ozone concentration reductions.

The magnitude of ozone concentration reductions from affected EGU sources is estimated to be roughly 10-fold greater in 2026 compared to 2023. Approximately 90% of the overall reference population experiences a fairly linear distribution of ozone concentration reductions, although the steepness of the distribution varies by regulatory alternative and facility type.

Distributions of ozone concentration changes across population demographics and affected facility types are reasonably similar across the three regulatory alternatives, although to differing magnitudes. Individuals who identify as Hispanic, Asian, American Indian, and those linguistically isolated experience proportionally smaller ozone concentration reductions from EGU and non-EGU NOx emissions reductions under the regulatory alternatives than the overall reference population in 2026.

As such, the very small difference shown in the distributional analyses of ozone concentration changes under the various regulatory alternatives in 2023 and 2026 provides

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MO3 ozone concentrations between 30-44 ppb. In contrast, the 20% of the overall reference population residing in areas of the highest baseline ozone concentrations experiences concentrations of between about 45-70 ppb.

additional evidence that the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns for population groups evaluated.

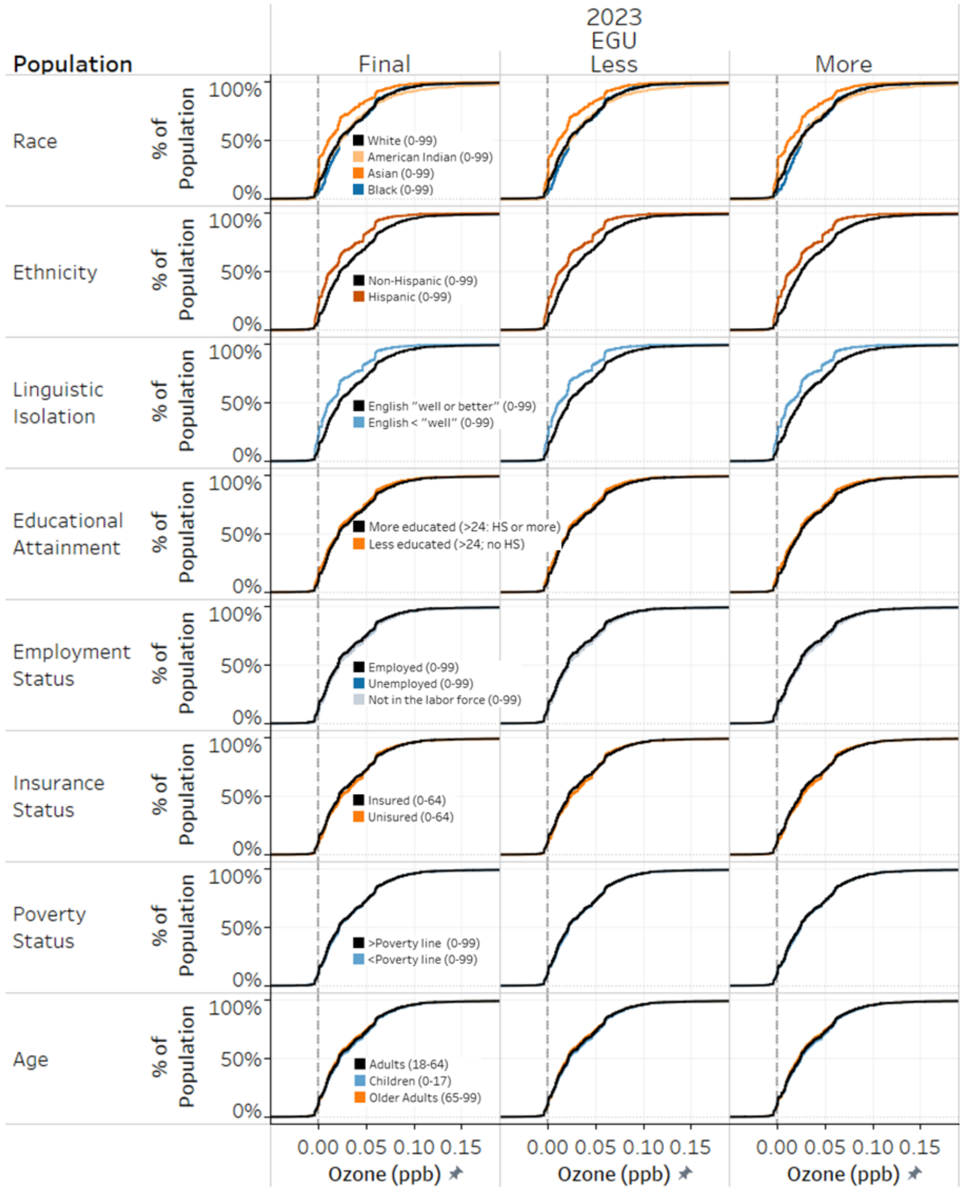


**Figure 7-5. Distributions of Ozone Concentration Changes Across Populations and Regulatory Alternatives in 2023**

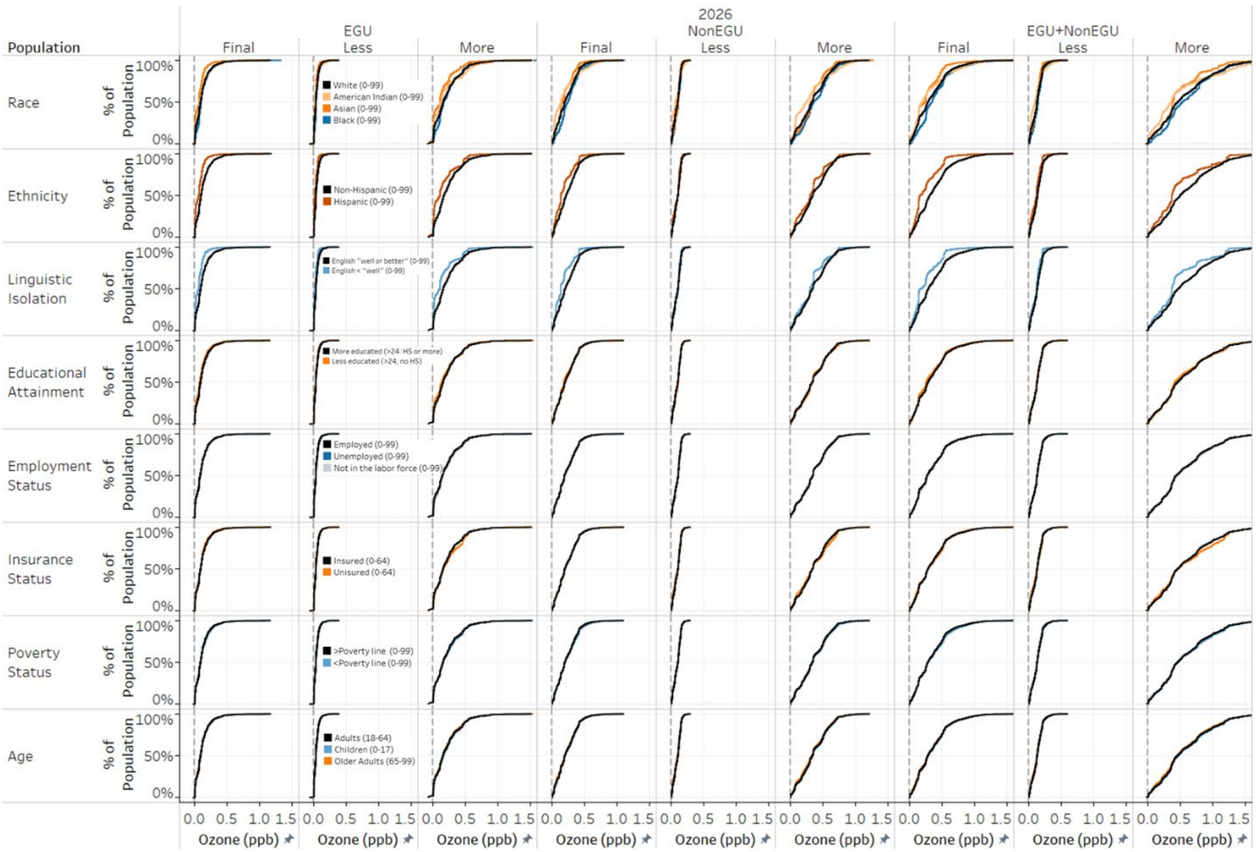


**Figure 7-6. Distributions of Ozone Concentration Changes Across Populations, Affected Facilities, and Regulatory Alternatives in 2026**

### *7.4.2 PM2.5 Exposure Analysis*

#### *7.4.2.1 National Aggregated Results*

While ozone is the targeted air pollutant of this final rulemaking, $PM_{2.5}$ reductions are a predicted co-pollutant reduction. $PM_{2.5}$ EJ exposure impacts of the policy options were not evaluated in the rule proposal as air quality spatial fields were unavailable. However, surfaces were developed for this final rulemaking, so $PM_{2.5}$ EJ impacts are provided here for EGU emission reductions in 2026.[178]

National average baseline $PM_{2.5}$ concentrations in micrograms per cubic meter (µg/m$^3$) in 2026 are shown in the colored column labelled "baseline" the heat map in Figure 7-7.[179]

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[178] Spatial fields of $PM_{2.5}$ concentration changes are predicted only from affected EGU sources in 2026.

[179] The 2026 baseline EGU $SO_2$ and, to some extent, $PM_{2.5}$ emissions were notably higher in the final case compared to the proposal, especially for units in Oklahoma. In Oklahoma, annual total EGU $SO_2$ emissions in the final 2026 baseline scenario were 14,595 tons per year compared to only 2 tons per year in the proposal 2026 baseline scenario which produced unrealistically high $PM_{2.5}$ concentrations in Oklahoma. The unrealistic $PM_{2.5}$ concentrations were

Concentrations in the "baseline" column represent the total estimated $PM_{2.5}$ exposure burden averaged over the 12-month calendar year and is colored to more easily visualize differences in average concentrations, with lighter blue coloring representing smaller average concentrations and darker blue coloring representing larger average concentrations. Average national disparities observed in the baseline of this rule are similar to those described by recent rules (e.g., the PM NAAQS Proposal), that is, populations with national average $PM_{2.5}$ concentrations higher than the reference population in 2026 ordered from most to least difference were: individuals who are linguistically isolated, Hispanic individuals, Asian individuals, Black individuals, the less educated, and children.

The three columns on the right side of Figure 7-7 provide information regarding how the final rulemaking will impact $PM_{2.5}$ concentrations across various populations from EGU controls under the rule, the less stringent alternative, and the more stringent alternative. Under the final rule in 2026, the difference in population-weighted seasonal average $PM_{2.5}$ reductions across demographic groups are relatively small and consistent.

The national-level assessment of $PM_{2.5}$ before and after implementation of this final rulemaking suggests that while EJ exposure disparities are present in the pre-policy scenario, meaningful EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated.

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removed from the spatial fields for the final rule 2026 alternatives by replacing the final rule EGU $SO_2$ and $PM_{2.5}$ emissions in Oklahoma with the corresponding 2026 baseline $SO_2$ and $PM_{2.5}$ emissions from the proposal. This impacts the magnitude of baseline $PM_{2.5}$ concentrations but should not impact changes due to the policy alternatives.

| Population | Group | Population Count | 2026 - Baseline | 2026 EGU Final | 2026 EGU Less | 2026 EGU More |
|---|---|---|---|---|---|---|
| Reference | Reference (0-99) | 352M | 7.34 | 0.01 | 0.00 | 0.04 |
| Race | White (0-99) | 276M | 7.24 | 0.01 | 0.00 | 0.04 |
| | American Indian (0-99) | 4M | 6.83 | 0.01 | 0.00 | 0.03 |
| | Asian (0-99) | 24M | 7.91 | 0.01 | 0.00 | 0.03 |
| | Black (0-99) | 49M | 7.64 | 0.02 | 0.00 | 0.04 |
| Ethnicity | Non-Hispanic (0-99) | 279M | 7.13 | 0.01 | 0.00 | 0.04 |
| | Hispanic (0-99) | 73M | 8.13 | 0.01 | 0.00 | 0.03 |
| Linguistic Isolation | English "well or better" (0-99) | 336M | 7.30 | 0.01 | 0.00 | 0.04 |
| | English < "well" (0-99) | 16M | 8.26 | 0.01 | 0.00 | 0.03 |
| Poverty Status | >Poverty line (0-99) | 296M | 7.31 | 0.01 | 0.00 | 0.04 |
| | <Poverty line (0-99) | 55M | 7.52 | 0.01 | 0.00 | 0.04 |
| Educational Attainment | More educated (>24: HS or more) | 207M | 7.24 | 0.01 | 0.00 | 0.04 |
| | Less educated (>24; no HS) | 34M | 7.67 | 0.01 | 0.00 | 0.04 |
| Employment Status | Employed (0-99) | 9M | 7.49 | 0.01 | 0.00 | 0.04 |
| | Unemployed (0-99) | 352M | 7.34 | 0.01 | 0.00 | 0.04 |
| | Not in the labor force (0-99) | 179M | 7.34 | 0.01 | 0.00 | 0.04 |
| Insurance Status | Insured (0-64) | 255M | 7.38 | 0.01 | 0.00 | 0.04 |
| | Unisured (0-64) | 31M | 7.47 | 0.01 | 0.00 | 0.04 |
| Age | Children (0-17) | 80M | 7.41 | 0.01 | 0.00 | 0.04 |
| | Adults (18-64) | 206M | 7.38 | 0.01 | 0.00 | 0.04 |
| | Older Adults (65-99) | 67M | 7.12 | 0.01 | 0.00 | 0.04 |
| Sex | Females (0-99) | 178M | 7.35 | 0.01 | 0.00 | 0.04 |
| | Males (0-99) | 174M | 7.33 | 0.01 | 0.00 | 0.04 |

**Figure 7-7. Heat Map of the National Average $PM_{2.5}$ Concentrations in the Baseline and Reductions in Concentrations Due to this Rulemaking Across Demographic Groups in 2026 ($\mu g/m^3$)**

### *7.4.2.2 State Aggregated Results*

We also provide $PM_{2.5}$ concentration reductions by state and demographic population in 2026 for the 48 states in the contiguous U.S, for the policy scenario only. In this heat map darker blue again indicates larger $PM_{2.5}$ reductions, with demographic groups shown as columns and each state as a row. On average, the state-specific reference populations are projected to experience reductions in $PM_{2.5}$ concentrations by up to 0.07 $\mu g/m^3$ in Arkansas and Louisiana. In all 48 states, populations potentially of concern are projected to experience similar $PM_{2.5}$ concentration reductions as the state-level reference population. Please note that population counts vary greatly by state, and that averaging results of the 48 states shown here will not reflect national population-weighted exposure estimates.

Therefore, whereas $PM_{2.5}$ exposure impacts vary considerably across states, the small magnitude of differential impacts expected by the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns within individual states.

EGU

2026

| State | Ref.. | Race | | | | Ethnicity | | Linguistic Isolation | | Poverty Status | | Educational Attainment | | Employment Status | | | Insurance Status | | Age | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Reference (0-99) | White (0-99) | American Indian (0-99) | Asian (0-99) | Black (0-99) | Non-Hispanic (0-99) | Hispanic (0-99) | English "well or better" (0-99) | English < "well" (0-99) | <Poverty line (0-99) | >Poverty line (0-99) | More educated (>24: HS or more) | Less educated (>24; no HS) | Employed | Unemployed | Not in the labor force | Insured | Unisured | Children (0-17) | Adults (18-64) | Older Adults (65-99) |
| Alabama | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Arizona | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Arkansas | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| California | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Colorado | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Connecticut | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Delaware | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Florida | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 |
| Georgia | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Idaho | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Illinois | 0.02 | 0.02 | 0.02 | 0.01 | 0.02 | 0.02 | 0.01 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Indiana | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Iowa | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Kansas | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Kentucky | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Louisiana | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.06 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Maine | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Maryland | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Massachusetts | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Michigan | 0.02 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Minnesota | 0.01 | 0.01 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Mississippi | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Missouri | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Montana | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Nebraska | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Nevada | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| New Hampshire | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| New Jersey | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| New Mexico | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| New York | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.01 | 0.00 | 0.01 | 0.00 | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| North Carolina | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| North Dakota | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Ohio | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Oklahoma | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Oregon | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Pennsylvania | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Rhode Island | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| South Carolina | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| South Dakota | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Tennessee | 0.03 | 0.02 | 0.02 | 0.03 | 0.03 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 |
| Texas | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 |
| Utah | 0.02 | 0.02 | 0.01 | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.01 | 0.02 | 0.02 | 0.01 |
| Vermont | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Virginia | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Washington | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| West Virginia | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Wisconsin | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Wyoming | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Figure 7-8. Heat Map of State Average $PM_{2.5}$ Concentration Reductions by Demographic Group for EGUs and Non-EGUs in 2026 ($\mu g/m^3$)**

#### 7.4.2.3 Distributional Results

We also present cumulative counts of each population exposed to ascending levels of $PM_{2.5}$ concentration changes across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanics) in the contiguous U.S. experience what change in $PM_{2.5}$ concentrations compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences similar concentration changes from EGU emission reductions under the three regulatory alternatives in 2026.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions (U.S. EPA 2021d, Section 6). For example, this analysis does not account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations to $PM_{2.5}$ exposure. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. Therefore, this analysis should not be used to assert that there are meaningful differences in $PM_{2.5}$ exposures associated with either the baseline or the rule.

As the baseline scenario is similar to that described by other RIAs, we focus on the $PM_{2.5}$ changes due to this final rulemaking. Distributions of 12 km gridded $PM_{2.5}$ concentration reductions from EGU control strategies of affected facilities under the three regulatory alternatives analyzed in this final rulemaking in 2026 are shown in Figure 7-9. For clarity, only above/below the poverty line and those who speak English “well or better”/“less than well” are shown and sex and the overall reference group are excluded from the cumulative distribution figures.

The vast majority of $PM_{2.5}$ concentration changes are less than 0.1 $\mu g/m^3$ in 2026. As was observed in the national average $PM_{2.5}$ concentration analysis (Section 7.4.2.1), there are slight differences in the $PM_{2.5}$ concentration changes across population demographics and regulatory alternatives in 2026 (Figure 7-9).

Distributions of $PM_{2.5}$ concentration changes across population demographics are reasonably similar across the three regulatory alternatives, although to differing magnitudes. As such, the very small difference shown in the distributional analyses of $PM_{2.5}$ concentration changes under the various regulatory alternatives in 2026 provides additional evidence that the final rule is not likely to meaningfully exacerbate or mitigate EJ concerns for population groups evaluated.

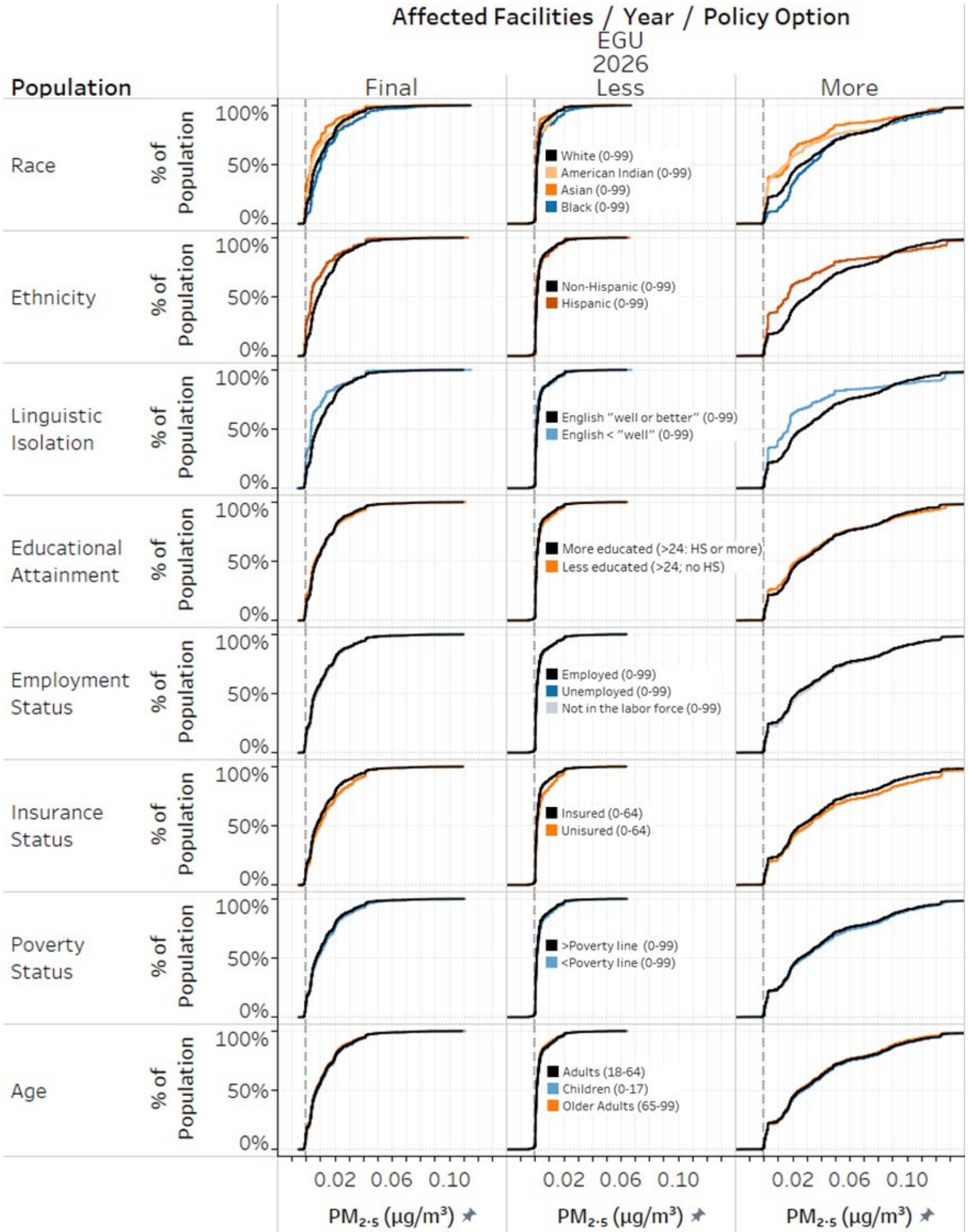


**Figure 7-9. Distributions of PM2.5 Concentration Changes Across Populations, Affected Facilities, and Regulatory Alternatives in 2026**

#### *7.4.2.4 Qualitative Assessment of $PM_{2.5}$ Health Impacts*

Health studies have shown a significant association between exposure to particle pollution and health risks, including premature death (U.S. EPA 2019 and Chapter 5). $PM_{2.5}$ reductions are expected from this action, but demographic-specific health impacts were not assessed for baseline or regulatory alternatives under this rulemaking, due to the small magnitude of predicted changes. However, in general, both recent publications and analyses by the EPA suggest that the burden of $PM_{2.5}$ exposures and impacts may disproportionately affect certain groups, such as Black and Hispanic populations (e.g., Bell 2012, Bravo 2016, Kelly 2021, U.S. EPA 2020, U.S. EPA 2021a, U.S. EPA 2021c).

## 7.5 Qualitative Assessment of $CO_2$

In 2009, under the *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* ("Endangerment Finding"), the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP),[180,181] the Intergovernmental Panel on Climate Change

[180] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[181] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. http://dx.doi.org/10.7930/J0R49NQX

(IPCC),[182,183,184,185] and the National Academies of Science, Engineering, and Medicine[186,187] add more evidence that the impacts of climate change raise potential environmental justice concerns. These reports conclude that poorer or predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the United States. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health*[188] found with high confidence that vulnerabilities are place- and time-specific, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts.

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[182] Oppenheimer, M., M. Campos, R.Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

[183] Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: Food security and food production systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 485-533.

[184] Smith, K.R., A.Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel,A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 709-754.

[185] IPCC, 2018: Global Warming of 1.5°C.An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.

[186] National Research Council. 2011. America's Climate Choices. Washington, DC: The National Academies Press. https://doi.org/10.17226/12781.

[187] National Academies of Sciences, Engineering, and Medicine. 2017. Communities in Action: Pathways to Health Equity. Washington, DC: The National Academies Press. https://doi.org/10.17226/24624.

[188] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment

In a 2021 report, EPA considered the degree to which four socially vulnerable populations—defined based on income, educational attainment, race and ethnicity, and age—may be more exposed to the highest impacts of climate change.[189] The report found that Black and African American populations are approximately 40% more likely to live in areas of the U.S. projected to experience the highest increases in mortality rates due to changes in extreme temperatures. Additionally, Hispanic and Latino individuals in weather-exposed industries were found to be 43% more likely to currently live in areas with the highest projected labor hour losses due to extreme temperatures. American Indian and Alaska Native individuals are projected to be 48% more likely to currently live in areas where the highest percentage of land may be inundated by sea level rise. Overall, the report confirmed findings of broader climate science assessments that Americans identifying as people of color, those with low-income, and those without a high school diploma face disproportionate risks of experiencing the most damaging impacts of climate change.

These findings suggest that $CO_2$ reductions may benefit disproportionately impacted populations. However, as we have not conducted the wide-ranging analyses that would be needed to assess the specific impacts of this rule on the multiple climate-EJ interactions described above, we cannot analyze the potential impacts of the final rule quantitatively.

### 7.6 Summary

As with all EJ analyses, data limitations make it quite possible that disparities may exist that our analysis did not identify. This is especially relevant for potential EJ characteristics, environmental impacts, and more granular spatial resolutions that were not evaluated. For example, here we provide a quantitative EJ assessment of ozone and $PM_{2.5}$ concentration changes from this rule but can only qualitatively discuss EJ impacts of $CO_2$ emission reductions. Therefore, this analysis is only a partial representation of the distributions of potential impacts. Additionally, EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, so results similar to those presented here should not be assumed for other rulemakings.

[189] U.S. EPA 2021e. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency, EPA 430-R-21-003.

For the rule, we quantitatively evaluate the proximity of affected facilities to potentially disadvantaged populations for consideration of local pollutants impacted by this rule but not modeled here (Section 7.3). We also quantitatively evaluate the potential for disproportionate pre- and policy-policy ozone and $PM_{2.5}$ exposures across different demographic groups (Section 7.4). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors, in this case, local $NO_2$ emitted from sources affected by the regulatory action for certain population groups of (Section 7.3). The baseline demographic proximity analyses suggest that larger percentages of Hispanic individuals, African American individuals, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African American individuals, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Relating these results to question 1 from Section 7.2, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (e.g., $NO_2$) for certain population groups of concern in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure or impact.

While the demographic proximity analyses may appear to parallel the baseline analysis of nationwide ozone and $PM_{2.5}$ exposures in certain ways, the two should not be directly compared. The baseline ozone and $PM_{2.5}$ exposure assessments are in effect an analysis of total burden in the contiguous U.S., and include various assumptions, such as the implementation of promulgated regulations. It serves as a starting point for both the estimated ozone and $PM_{2.5}$ changes due to this rule as well as a snapshot of air pollution concentrations in the near future.

The baseline ozone and $PM_{2.5}$ exposure analyses respond to question 1 from EPA's EJ Technical Guidance document more directly than the proximity analyses, as they evaluate a form of the environmental stressor primarily affected by the regulatory action (Section 7.4). Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanic individuals, Asian individuals, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. Individuals who identify as American Indian may also experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline.

Finally, we evaluate how post-policy regulatory alternatives of this final rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. We infer that disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration due to the small magnitude of the concentration changes associated with this rulemaking across demographic populations relative to baseline burden disparities (question 2). Also, due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration, compared to the baseline (question 3). Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in many areas, including those areas that struggle to attain or maintain the ozone NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated.

This EJ air quality analysis concludes that there are disparities across various populations in the pre-policy baseline scenario (EJ question 1) and infer that these disparities are likely to persist after promulgation of this final rulemaking (EJ question 2). This EJ assessment also suggests that this action will neither mitigate nor exacerbate disparities across populations of EJ concern analyzed (EJ question 3) at the national scale in a meaningful way.

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## CHAPTER 8: COMPARISON OF BENEFITS AND COSTS

### Overview

The EPA performed an analysis to estimate the costs and benefits of compliance with the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (Transport FIP for the 2015 ozone NAAQS) and more and less stringent alternatives.

Consistent with OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (2010), this RIA presents the benefits and costs of the final rule from 2023 through 2042. The estimated health benefits are expected to arise from reduced $PM_{2.5}$ and ozone concentrations, and the estimated climate benefits are from reduced greenhouse gas (GHG) emissions. The estimated costs for EGUs are the costs of installing and operating controls and the increased costs of producing electricity. The estimated costs for non-EGUs are the costs of installing and operating controls to meet the ozone season emissions limits. The estimated costs for non-EGUs do not include monitoring, recordkeeping, reporting, or testing costs. Unquantified benefits and costs are described qualitatively.

The more and less stringent alternatives differ from the final rule in that they set different $NO_X$ ozone season emission budgets for the affected EGUs and different dates for compliance with the backstop emission rate. All three scenarios use emission budgets that were developed using uniform control stringency represented by $1,800 per ton of $NO_X$ (2016$) in 2023 and $11,000 per ton of NOx (2016$) in 2026. The final rule and less-stringent alternative defer the backstop emission rate for certain EGUs until the 2030 run year,[190] while the more stringent alternative imposes the backstop emission rate in the 2025 run year (reflective of imposition in the 2026 calendar year). The backstop emission rate is imposed beginning in the relevant run

[190] 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

year (2025 or 2030, depending on scenario), on all coal units within the 19-state region that are greater than 100 MW and lack SCR controls (excepting circulating fluidized bed (CFB) units).[191]

The rule also includes $NO_X$ emissions limitations with an initial compliance date of 2026 applicable to certain non-EGU stationary sources in 20 states. The rule establishes $NO_X$ emissions limitations during the ozone season for the following unit types: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors or incinerators in Solid Waste Combustors or Incinerators.

In order to implement the OMB Circular A-4 guidance for fulfilling Executive Order (E.O.) 12866 to assess one less stringent and one more stringent alternative to the rule, we analyzed a less stringent non-EGU alternative that would require less stringent control technologies for the reciprocating internal combustion engines in Pipeline Transportation of Natural Gas and boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. We analyzed a more stringent non-EGU alternative that would require more stringent control technologies for the kilns in Cement and Concrete Products Manufacturing, the furnaces in Glass and Glass Products Manufacturing, and the natural gas-fired boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. A summary of the emissions limits can be found in Section I.B. of the preamble.

## 8.1 Results

This RIA evaluates how EGUs and non-EGUs covered by the rule are expected to reduce their emissions in response to the requirements and flexibilities provided by the remedy implemented by the Transport FIP for the 2015 ozone NAAQS and the benefits, costs, and

[191] The 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

impacts of their expected compliance behavior. This chapter summarizes these results. Table 8-1 shows the ozone season $NO_X$ emissions reductions expected from the rule as well as the more and less stringent alternatives analyzed from 2023 through 2030, and for 2035 and 2042. In addition, Table 8-1 shows the ozone season and annual $NO_X$, as well as annual $SO_2$, $PM_{2.5}$, and $CO_2$ emissions reductions expected nationwide from the rule as well as the more and less stringent alternatives analyzed from 2023 through 2027, and for 2030, 2035 and 2042.

Table 8-2 below provides a summary of the 2019 ozone season emissions for non-EGUs for the 20 states subject to the Transport FIP for the 2015 ozone NAAQS in 2026, along with the estimated ozone season reductions for the rule and the less and more stringent alternatives.

For 2023, total ozone season NOx emissions reductions of 10,000 tons are from EGUs; for 2026 total ozone season NOx emissions reductions of 70,000 tons are from EGUs and non-EGUs, and for 2030 total ozone season NOx emissions reductions of 79,000 tons are from EGUs and non-EGUs.

**Table 8-1. EGU Ozone Season $NO_X$ Emissions Changes and Annual Emissions Changes for $NO_X$, $SO_2$, $PM_{2.5}$, and $CO_2$ for the Regulatory Control Alternatives from 2023 - 2042**

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **2023** | | | |
| NOx (ozone season) | 10,000 | 10,000 | 10,000 |
| NOx (annual) | 15,000 | 15,000 | 15,000 |
| $SO_2$ (annual)* | 1,000 | 3,000 | 1,000 |
| $CO_2$ (annual, thousand metric) | - | - | - |
| $PM_{2.5}$ (annual) | - | - | - |
| **2024** | | | |
| NOx (ozone season) | 21,000 | 10,000 | 33,000 |
| NOx (annual) | 25,000 | 15,000 | 57,000 |
| $SO_2$ (annual) | 19,000 | 5,000 | 59,000 |
| $CO_2$ (annual, thousand metric) | 10,000 | 4,000 | 20,000 |
| $PM_{2.5}$ (annual) | 1,000 | - | 1,000 |
| **2025** | | | |
| NOx (ozone season) | 32,000 | 10,000 | 56,000 |
| NOx (annual) | 35,000 | 15,000 | 99,000 |
| $SO_2$ (annual) | 38,000 | 7,000 | 118,000 |
| $CO_2$ (annual, thousand metric) | 21,000 | 8,000 | 40,000 |
| $PM_{2.5}$ (annual) | 2,000 | 1,000 | 2,000 |
| **2026** | | | |
| NOx (ozone season) | 25,000 | 8,000 | 49,000 |
| NOx (annual) | 29,000 | 12,000 | 88,000 |
| $SO_2$ (annual) | 29,000 | 5,000 | 104,000 |
| $CO_2$ (annual, thousand metric) | 16,000 | 6,000 | 34,000 |

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| $PM_{2.5}$ (annual) | 1,000 | - | 2,000 |
| **2027** | | | |
| NOx (ozone season) | 19,000 | 6,000 | 43,000 |
| NOx (annual) | 22,000 | 9,000 | 78,000 |
| $SO_2$ (annual) | 21,000 | 4,000 | 91,000 |
| $CO_2$ (annual, thousand metric) | 10,000 | 3,000 | 28,000 |
| $PM_{2.5}$ (annual) | 1,000 | - | 2,000 |
| **2030** | | | |
| NOx (ozone season) | 34,000 | 33,000 | 31,000 |
| NOx (annual) | 62,000 | 59,000 | 50,000 |
| $SO_2$ (annual) | 93,000 | 98,000 | 51,000 |
| $CO_2$ (annual, thousand metric) | 26,000 | 23,000 | 8,000 |
| $PM_{2.5}$ (annual) | 1,000 | 1,000 | - |
| **2035** | | | |
| NOx (ozone season) | 29,000 | 30,000 | 27,000 |
| NOx (annual) | 46,000 | 46,000 | 41,000 |
| $SO_2$ (annual) | 21,000 | 19,000 | 15,000 |
| $CO_2$ (annual, thousand metric) | 16,000 | 15,000 | 8,000 |
| $PM_{2.5}$ (annual) | 1,000 | 1,000 | - |
| **2042** | | | |
| NOx (ozone season) | 22,000 | 22,000 | 22,000 |
| NOx (annual) | 23,000 | 22,000 | 21,000 |
| $SO_2$ (annual) | 15,000 | 15,000 | 7,000 |
| $CO_2$ (annual, thousand metric) | 9,000 | 8,000 | 4,000 |
| $PM_{2.5}$ (annual) | - | - | - |

**Table 8-2. Non-EGU Ozone Season $NO_X$ Emissions and Emissions Reductions for the Final Rule and the Less and More Stringent Alternatives**

| State | 2019 Ozone Season Emissions[a] | Final Rule – Ozone Season NOx Reductions | Less Stringent – Ozone Season NOx Reductions | More Stringent – Ozone Season NOx Reductions |
|---|---|---|---|---|
| AR | 8,790 | 1,546 | 457 | 1,690 |
| CA | 16,562 | 1,600 | 1,432 | 4,346 |
| IL | 15,821 | 2,311 | 751 | 2,991 |
| IN | 16,673 | 1,976 | 1,352 | 3,428 |
| KY | 10,134 | 2,665 | 583 | 3,120 |
| LA | 40,954 | 7,142 | 1,869 | 7,687 |
| MD | 2,818 | 157 | 147 | 1,145 |
| MI | 20,576 | 2,985 | 760 | 5,087 |
| MO | 11,237 | 2,065 | 579 | 4,716 |
| MS | 9,763 | 2,499 | 507 | 2,650 |
| NJ | 2,078 | 242 | 242 | 258 |
| NV | 2,544 | 0 | 0 | 0 |
| NY | 5,363 | 958 | 726 | 1,447 |
| OH | 18,000 | 3,105 | 1,031 | 4,006 |
| OK | 26,786 | 4,388 | 1,376 | 5,276 |
| PA | 14,919 | 2,184 | 1,656 | 4,550 |
| TX | 61,099 | 4,691 | 1,880 | 9,963 |
| UT | 4,232 | 252 | 52 | 615 |
| VA | 7,757 | 2,200 | 978 | 2,652 |
| WV | 6,318 | 1,649 | 408 | 2,100 |
| **Totals** | **302,425** | **44,616** | **16,786** | **67,728** |

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

As shown in Chapter 4, the estimated annual compliance costs to implement the rule, as described in this RIA, are approximately $57 million in 2023 and $570 million in 2026 (2016$). This RIA uses compliance costs as a proxy for social costs as mentioned in Chapter 4. As shown in Chapter 5, the estimated monetized health benefits from reduced $PM_{2.5}$ and ozone concentrations from implementation of the rule are approximately $100 and $820 million in 2023 (2016$, based on a real discount rate of 3 percent). As shown in Chapter 5, the estimated monetized climate benefits from reduced GHG emissions are approximately $5 million in 2023 (2016$, based on a real discount rate of 3 percent). For 2026, the estimated monetized health benefits from implementation of the rule are approximately $3,200 and $14,000 million (2016$, based on a real discount rate of 3 percent). The estimated monetized climate benefits from reduced GHG emissions are approximately $830 million in 2026 (2016$, based on a real discount rate of 3 percent).

The EPA calculates the monetized net benefits of the rule by subtracting the estimated monetized compliance costs from the estimated monetized health and climate benefits in 2023, 2026, and 2030. The benefits include those to public health associated with reductions in $PM_{2.5}$ and ozone concentrations, as well as those to climate associated with reductions in GHG emissions. The annual monetized net benefits of the rule in 2023 (in 2016$) are approximately $48 and $760 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2026 are approximately $3,700 and $14,000 million using a 3 percent real discount rate. The annual monetized net benefits of the rule in 2030 are approximately $3,600 and $15,000 million using a 3 percent real discount rate. Table 8-3 presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2023. Table 8-4 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2026.

Table 8-5 presents a summary of these impacts for the rule and the more and less stringent alternatives for 2030. These results present an incomplete overview of the effects of the rule because important categories of benefits -- including benefits from reducing other types of air pollutants, and water pollution – were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than this table reflects.

**Table 8-3. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2023 for the U.S. (millions of 2016$)** [a,b,c]

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits**[c] | $100 and $820 | $100 and $810 | $110 and $840 |
| **Climate Benefits** | $5 | $4 | $5 |
| **Total Benefits** | $100 and $820 | $100 and $820 | $110 and $840 |
| **Costs**[d] | $57 | $56 | $49 |
| **Net Benefits** | **$48 and $760** | **$48 and $760** | **$66 and $800** |

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

**Table 8-4. Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2026 for the U.S. (millions of 2016$)** [a,b,c]

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits**[c] | $3,200 and $14,000 | $950 and $4,600 | $8,300 and $29,000 |
| **Climate Benefits** | $1,100 | $420 | $2,100 |
| **Total Benefits** | $4,300 and $15,000 | $1,400 and $5,000 | $10,000 and $31,000 |
| **Costs**[d] | $570 | $110 | $2,100 |
| **Net Benefits** | **$3,700 and $14,000** | **$1,300 and $4,900** | **$8,300 and $29,000** |

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

**Table 8-5**. **Monetized Benefits, Costs, and Net Benefits of the Final Rule and Less and More Stringent Alternatives for 2030 for the U.S. (millions of 2016$)** [a,b,c]

| | Final Rule | Less Stringent Alternative | More Stringent Alternative |
|---|---|---|---|
| **Health Benefits**[c] | $3,400 and $15,000 | $1,000 and $4,900 | $9,000 and $31,000 |
| **Climate Benefits** | $1,500 | $1,300 | $500 |
| **Total Benefits** | $4,900 and $16,000 | $2,300 and $6,200 | $9,500 and $31,000 |
| **Costs**[d] | $1,300 | $920 | $2,100 |
| **Net Benefits** | **$3,600 and $15,000** | **$1,400 and $5,300** | **$7,400 and $29,000** |

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3%.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4-8.

As part of fulfilling analytical guidance with respect to E.O. 12866, the EPA presents estimates of the present value (PV) of the monetized benefits and costs over the twenty-year period 2023 to 2042. To calculate the present value of the social net-benefits of the rule, annual benefits and costs are discounted to 2023 at 3 percent and 7 discount rates as recommended by OMB's Circular A-4. The EPA also presents the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2023 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates mentioned earlier in the RIA. Table 8-6 below includes the undiscounted streams of health benefits, climate benefits, costs, and net benefits from 2023 to 2042. Table 8-7 below provides the comparison of benefits and costs in PV and EAV terms for the rule. Estimates in the table are presented as rounded values. For the twenty-year period of 2023 to 2042, the PV of the net benefits, in 2016$ and discounted to 2023, is $200,000 million when using a 3 percent discount rate and $140,000 million when using a 7 percent discount rate. The EAV is $13,000 million per year when using a 3 percent discount rate and $12,000 million when using a 7 percent discount rate.

**Table 8-6. Undiscounted Streams Health Benefits, Climate Benefits, Costs, and Net Benefits for 2023 – 2042 (millions of 2016$)**

| | Health Benefits[a] | | Climate Benefits[b] | Costs | Net Benefits | |
|---|---|---|---|---|---|---|
| | 3% | 7% | 3% | | 3% | 7% |
| 2023 | $820 | $730 | $5 | $57 | $770 | $680 |
| 2024 | $840 | $750 | $1,100 | ($5) | $1,400 | $1,300 |
| 2025 | $9,100 | $8,100 | $1,100 | ($5) | $10,000 | $9,200 |
| 2026 | $14,000 | $12,000 | $1,100 | $570 | $14,000 | $12,000 |
| 2027 | $14,000 | $13,000 | $260 | $600 | $14,000 | $13,000 |
| 2028 | $14,000 | $12,000 | $270 | $600 | $14,000 | $12,000 |
| 2029 | $14,000 | $13,000 | $270 | $600 | $14,000 | $13,000 |
| 2030 | $15,000 | $13,000 | $1,500 | $1,300 | $15,000 | $13,000 |
| 2031 | $15,000 | $13,000 | $1,500 | $1,300 | $15,000 | $13,000 |
| 2032 | $15,000 | $14,000 | $960 | $1,400 | $15,000 | $14,000 |
| 2033 | $15,000 | $14,000 | $980 | $1,400 | $15,000 | $14,000 |
| 2034 | $16,000 | $14,000 | $1,000 | $1,400 | $16,000 | $14,000 |
| 2035 | $16,000 | $14,000 | $1,000 | $1,400 | $16,000 | $14,000 |
| 2036 | $16,000 | $15,000 | $1,000 | $1,400 | $16,000 | $15,000 |
| 2037 | $17,000 | $15,000 | $1,000 | $1,400 | $17,000 | $15,000 |
| 2038 | $17,000 | $15,000 | $1,300 | $1,400 | $17,000 | $15,000 |
| 2039 | $17,000 | $15,000 | $1,400 | $1,400 | $17,000 | $15,000 |
| 2040 | $17,000 | $15,000 | $1,400 | $1,400 | $17,000 | $15,000 |
| 2041 | $17,000 | $16,000 | $1,400 | $1,400 | $17,000 | $16,000 |
| 2042 | $18,000 | $16,000 | $1,400 | $1,400 | $18,000 | $16,000 |

[a] We assume that there is a cessation lag between the change in exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to exposures occur in a distributed fashion over the 20 years following exposure, which affects the valuation of mortality benefits at different discount rates. The table reflects the benefits associated with the higher of the two point estimates from two different epidemiologic studies. We present the benefits calculated at real discount rates of 3 and 7 percent.
[b] We include the climate benefits calculated at a 3 percent discount rate.

**Table 8-7. Summary of Present Values and Equivalent Annualized Values for the 2023-2042 Timeframe for Estimated Monetized Compliance Costs, Benefits, and Net Benefits for the Final Rule (millions of 2016$, discounted to 2023)[a,b]**

| | Health Benefits | | Climate Benefits | Cost[c] | | Net Benefits | |
|---|---|---|---|---|---|---|---|
| | 3% | 7% | 3% | 3% | 7% | 3% | 7% |
| 2023 | $820 | $730 | $5 | $57 | $57 | $770 | $680 |
| 2024 | $810 | $700 | $1,000 | ($5) | ($5) | $1,300 | $1,200 |
| 2025 | $8,600 | $7,100 | $1,000 | ($5) | ($4) | $9,600 | $8,100 |
| 2026 | $13,000 | $10,000 | $1,000 | $520 | $460 | $13,000 | $10,000 |
| 2027 | $13,000 | $9,700 | $230 | $530 | $450 | $13,000 | $9,700 |
| 2028 | $12,000 | $8,900 | $230 | $510 | $420 | $12,000 | $8,700 |
| 2029 | $12,000 | $8,500 | $230 | $500 | $400 | $12,000 | $8,800 |
| 2030 | $12,000 | $8,200 | $1,200 | $1,000 | $800 | $12,000 | $8,600 |
| 2031 | $12,000 | $7,800 | $1,200 | $1,000 | $740 | $12,000 | $8,200 |
| 2032 | $12,000 | $7,500 | $740 | $1,100 | $760 | $12,000 | $7,700 |
| 2033 | $11,000 | $7,000 | $730 | $1,000 | $710 | $11,000 | $7,200 |
| 2034 | $11,000 | $6,700 | $720 | $1,000 | $660 | $11,000 | $6,900 |
| 2035 | $11,000 | $6,400 | $710 | $970 | $620 | $11,000 | $6,500 |
| 2036 | $11,000 | $6,100 | $700 | $950 | $580 | $11,000 | $6,300 |
| 2037 | $11,000 | $5,800 | $690 | $920 | $540 | $11,000 | $6,000 |
| 2038 | $11,000 | $5,400 | $860 | $890 | $500 | $11,000 | $5,700 |
| 2039 | $10,000 | $5,100 | $850 | $870 | $470 | $9,900 | $5,400 |
| 2040 | $10,000 | $4,900 | $830 | $840 | $440 | $10,000 | $5,300 |
| 2041 | $10,000 | $4,600 | $820 | $820 | $410 | $9,900 | $4,900 |
| 2042 | $10,000 | $4,400 | $810 | $790 | $380 | $9,800 | $4,600 |
| **PV 2023-2042** | **$200,000** | **$130,000** | **$15,000** | **$14,000** | **$9,400** | **$200,000** | **$140,000** |
| **EAV 2023-2042** | **$13,000** | **$12,000** | **$970** | **$910** | **$770** | **$13,000** | **$12,000** |

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

| | | |
|---|---|---|
| United States<br>Environmental Protection<br>Agency | Office of Air Quality Planning and Standards<br>Health and Environmental Impacts Division<br>Research Triangle Park, NC | Publication No. EPA-452/R-23-001<br>March 2023 |