UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

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Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

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ES.1 Introduction

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[1] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[2] Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021.[3] At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources is available to the power sector—including carbon capture and sequestration/storage (CCS), co-firing with less GHG-intensive fuels, and more efficient generation. Congress has also acted to provide funding and other incentives to encourage the deployment of various technologies, including CCS, to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and new source performance standards (NSPS) that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Specifically, the EPA is first finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units

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[1] 74 FR 66496 (December 15, 2009).

[2] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

[3] https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines at this time and plans to expeditiously issue an additional proposal that more comprehensively addresses GHG emissions from this portion of the fleet. The EPA acknowledges that the share of GHG emissions from existing fossil fuel-fired combustion turbines has been growing and is projected to continue to do so, particularly as emissions from other portions of the fleet decline, and that it is vital to regulate the GHG emissions from these sources consistent with CAA section 111.

These final actions ensure that the new and existing fossil fuel-fired EGUs that are subject to these rules reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

In accordance with Executive Order (E.O). 12866 and 13563, the guidelines of OMB Circular A-4 and EPA's *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2014), the RIA analyzes the benefits and costs associated with the projected emissions reductions under the requirements of the final rules, and two alternative sets of requirements to inform EPA and the public about these projected impacts.[4]

ES.2 Regulatory Requirements

These final actions include the repeal of the ACE Rule, BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, and BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired steam

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[4] Circular A-4 was recently revised. The effective date of the revised Circular A-4 (2023) is March 1, 2024, for regulatory analyses received by OMB in support of proposed rules, interim final rules, and direct final rules, and January 1, 2025, for regulatory analyses received by OMB in support of other final rules. For all other rules, Circular A-4 (2003) is applicable until those dates.

generating units. See Section I.C of the final rule preamble for a summary of the major provisions of these regulations.

ES.3 Baseline and Analysis Years

The impacts of final regulatory actions are evaluated relative to a modeled baseline that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. EPA used the Integrated Planning Model (IPM)[5] to conduct the electric generating units (EGU) analysis discussed in this section, relying on the EPA's Power Sector Platform 2023 Using IPM to establish the baseline for this analysis. For a detailed description please see Section 3 of this document. EPA frequently updates the power sector modeling baseline to reflect the latest available electricity demand forecasts from the U.S. Energy Information Administration (EIA) at the time the modeling was completed as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements. The electricity supply baseline includes the final Good Neighbor Plan (GNP), the Revised Cross-State Air Pollution Rule (CSAPR) Update, CSAPR Update, and CSAPR, as well as the 2012 Mercury and Air Toxics Standards. The power sector baseline also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the recently finalized 2020 ELG and CCR rules. This version of the model ("EPA's Power Sector Platform 2023 Using IPM") also includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA)[6]. The modeling documentation, available in the docket, includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the

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[5] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.

[6] The Inflation Reduction Act (IRA) contains tax credit provisions that affect power sector operations, which are incorporated into the IPM modeling. Details are included the IPM documentation. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4. Documentation available at: https://www.epa.gov/airmarkets/power-sector-modeling

model.[7] Also, see Section 3 for additional detail about the power sector baseline for this RIA. Additionally, EPA conducted sensitivity analyses that examined the impacts of several recently finalized EPA rulemakings (including MATS RTR, ELG, and EPA's LDV, MDV and HDV vehicle rules) in addition to the 111 rulemaking, as well as exploring alternative assumptions around gas prices and demand.

This RIA evaluates the benefits, costs, and certain impacts of compliance with three illustrative scenarios: the final rules and two alternative regulatory option scenarios which assume both existing and new source GHG mitigation requirements. For details of the controls modeled for each of the source categories under the three illustrative scenarios, please see Section 3.2 of this RIA.

We evaluated the potential benefits, costs, and net benefits of the three illustrative scenarios for the years 2024 to 2047 from the perspective of 2024, using the discount rates of two percent, three percent, and seven percent.[8] In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These snapshot years are 2028, 2030, 2035, 2040 and 2045. The Agency believes that these specific years are each representative of several surrounding years, which enables the analysis of costs and benefits over the timeframe of 2024 to 2047. The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the regulatory impacts of the final 111(b) new source performance standards on the power sector will begin. However, because the Agency estimates that some monitoring, reporting, and recordkeeping (MR&R) costs may be incurred in 2024, we analyze compliance costs in years before 2028. Therefore, while MR&R costs analysis is presented beginning in the year 2024, the detailed assessment of costs, emissions impacts, and benefits begins in the year 2028. The analysis timeframe concludes in 2047, as this is the last year that may be represented with the analysis conducted for the specific

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[7] For a discussion on the impacts of the IRA from a range of models including EPA IPM, please see: Bistline, J., et al., Emissions and energy impacts of the Inflation Reduction Act. Science, 2023. 380(6652): p. 1324-1327. DOI: 10.1126/science. adg3781. Available from: https://www.science.org/ doi/10.1126/science.adg3781

[8] Results using the 2 percent discount rate were not included in the proposals for these actions. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates), which is an estimate of consumption-based discount rate. We include cost and benefits results calculated using a 2 percent discount rate consistent with the update to Circular A-4 (OMB, 2023).

year of 2045. While the results are described and presented in more detail later in this executive summary and throughout the RIA, we present the high-level results of the analysis here.

ES.4 Emissions Impacts

Table ES-1 presents the estimated impact on power sector emissions in the contiguous U.S. resulting from compliance with the final rules as modeled by the illustrative final rules scenario. The projections indicate that the illustrative final rules scenario results in national, annual emission reductions of CO_2, direct $PM_{2.5}$, NO_X, and SO_2 for each of the snapshot years analyzed. The illustrative alternative 1 and alternative 2 scenarios result in national emission reductions of CO_2, NO_X, and SO_2 throughout the year for each of the snapshot years analyzed but increases in 2040 in direct $PM_{2.5}$ and mercury. Under the illustrative final rules scenario, the cumulative CO_2 emission reductions over the 2028 to 2047 timeframe are estimated to be 1,382 million metric tons. Under the alternative 1 and alternative 2 illustrative scenarios, cumulative CO_2 emission reductions over the 2028 to 2047 timeframe are estimated to be 1,365 million metric tons and 1,303 million metric tons, respectively.[9]

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[9] See Table 4-2 for annual CO_2 emission reductions.

Table ES-1 Projected EGU Emissions and Emissions Changes for the Three Illustrative Scenarios for 2028, 2030, 2035, 2040, and 2045 [a]

	CO$_2$ (million metric tons)	Annual NO$_X$ (thousand short tons)	Ozone Season NO$_X$ (thousand short tons)[b]	Annual SO$_2$ (thousand short tons)	Direct PM$_{2.5}$ (thousand short tons)	Mercury (tons)
Final Rules						
2028	-38	-20	-6	-34	-2	-0.1
2030	-50	-20	-7	-20	-2	-0.1
2035	-123	-49	-19	-90	-1	-0.1
2040	-54	-6	-6	-4	2	0.2
2045	-42	-24	-14	-41	-2	-0.2
Alternative 1						
2028	-36	-19	-6	-30	-2	-0.1
2030	-48	-20	-7	-16	-2	-0.1
2035	-124	-51	-20	-90	-2	-0.1
2040	-53	-7	-6	-4	1	0.2
2045	-40	-24	-14	-41	-2	-0.2
Alternative 2						
2028	-32	-17	-5	-28	-1	-0.1
2030	-27	-11	-4	-15	-1	0.0
2035	-122	-48	-18	-94	-1	-0.1
2040	-53	-5	-6	-8	2	0.3
2045	-40	-24	-14	-41	-2	-0.1

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

[b] Ozone season is the May through September period in this analysis.

ES.5 Compliance Costs

The compliance cost estimates presented in this RIA are based on IPM projection supplemented with cost estimates for MR&R. As described previously, this RIA evaluates three illustrative scenarios: the final rules, alternative 1, and alternative 2. The alternative 1 and alternative 2 scenarios assume the definition of annual capacity factor for baseload operation for new turbines is 50 percent, whereas under the final rules scenario baseload is defined as 40 percent annual capacity factor. The final rules and alternative 1 scenarios assume all medium-term existing coal-fired steam generating units must co-fire at least 40 percent natural gas by 2030, while the alternative 2 scenario assumes that all medium-term existing coal fired steam generating units must co-fire at least 40 percent natural gas by 2035.

Table ES-2 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates[10] for the illustrative final rules scenario

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[10] Compliance costs refer to the difference between policy and baseline IPM projected capital, O&M, fuel, transmission, and CO$_2$ storage and transportation costs. Other costs are not accounted for. Please see Sections 3.5 and 5.2 for further discussion of the differences between compliance costs and social costs.

and the alternative scenarios. We present the PV of the costs over the 24-year period of 2024 to 2047. We also present the equivalent annualized value (EAV), which represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost for each year of the analysis. Section 3 reports how annual power costs are projected to change over the time period of analysis.[11]

Table ES-2 Total National Compliance Cost Estimates for the Three Illustrative Scenarios (discounted to 2024, billion 2019 dollars)

	2% Discount Rate		3% Discount Rate		7% Discount Rate	
	PV	EAV	PV	EAV	PV	EAV
Final Rules	19	0.98	15	0.91	7.5	0.65
Alternative 1	19	0.99	16	0.93	7.8	0.68
Alternative 2	19	0.98	15	0.91	7.2	0.63

Note: Values have been rounded to two significant figures.

Projected compliance costs are similar across the scenarios. Costs peak in 2035 across all scenarios, reflecting the date of imposition of the final Emission Guidelines for coal-fired steam generating units and tightening NSPS requirements. The final rules scenario results in the greatest early buildout of renewable energy, resulting in the lowest near-term costs and higher longer-term costs. As a result, over the 2024 - 2047 time period, the final rules scenario shows lower costs than alternative 1. However, over the entire forecast period of 2024 - 2055, costs are higher under the final rules.

Tax credits under the IRA directly subsidize lower emitting generation (i.e., CCS, RE etc.). The baseline as a result continues to show reductions in thermal generation and capacity share over the forecast period. The addition of the policy further accentuates these trends, but the IRA continues to play an important role. As a result, costs remain lower than they would absent the IRA.

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[11] Results using the 2 percent discount rate were not included in the proposal for this action. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rule used these two recommended rates. In November 2023, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates), which is an estimate of consumption-based discount rate. We include cost and benefits results calculated using a 2 percent discount rate consistent with the update to Circular A-4 (OMB, 2023).

ES.6 Benefits

This section reports the estimated monetized climate and health benefits associated with emission reductions for each of the three illustrative scenarios described in prior sections and discusses other unquantified benefits.

ES.6.1 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 these final rules. Climate benefits from reducing emissions of CO_2 are monetized using estimates of the social cost of carbon (SC-CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). As noted in the proposal for these rulemakings, the EPA presented these updated SC-CO_2 estimates in sensitivity analysis in the RIA for the agency's December 2022 Oil and Gas NSPS/EG Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review". The EPA solicited public comment and conducted an external peer review of these estimates, and the Agency has used the estimates in the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking (U.S. EPA, 2023b). See Section 4.2 of this RIA for more discussion of the approach to monetization of the climate benefits associated with these rules.

ES.6.2 Health Benefits

These rules are expected to reduce annual, national emissions of direct $PM_{2.5}$, NO_X, and SO_2. 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. These final rules are expected to reduce ozone season NO_X emissions. In the presence of sunlight, NO_X, and volatile organic compounds (VOCs) undergo chemical reactions in the atmosphere resulting in ozone formation. Reducing NO_X emissions reduces human exposure to ozone and the incidence of ozone-related health effects in most locations, though ozone response to NO_X emissions reductions depends on local conditions.

In this RIA, EPA estimates national-level health benefits resulting from the changes in $PM_{2.5}$ and ozone concentrations expected to occur with these final rules. The health effect endpoints, effect estimates, and benefit unit-values, and how they were selected, are described in the Technical Support Document (TSD) titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2023a). Our approach for updating the endpoints and to identify suitable epidemiological studies, baseline incidence rates, population demographics, and valuation estimates is summarized in Section 4.3.

ES.6.3 Additional Unquantified Benefits

Data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with direct exposure to hazardous air pollutants (HAPs), NO_2, and SO_2, independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone. In addition, these limitations prevented quantification of welfare benefits accrued due to reduced pollutant impacts on ecosystem and reductions in visibility impairment. 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 HAPs, ozone, $PM_{2.5}$, NO_2, or SO_2. For a qualitative description of these and potential water quality benefits, please see Section 4.4 of this RIA.

ES.6.4 Total Climate and Health Benefits

Table ES-3 presents the total monetized climate and health benefits for the illustrative final rules scenario and the alternative scenarios.[12]

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[12] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with EPA's updated estimates of the SC-CO_2. OMB has long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. Because the SC-CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-CO_2. See Section 4.2 for more discussion.

Table ES-3 Benefits for the Three Illustrative Scenarios, (discounted to 2024, billion 2019 dollars)[a]

	All Benefits Calculated using 2% Discount Rate					
	Climate Benefits [b]		PM$_{2.5}$ and O$_3$-related Health Benefits [c]		**Total Benefits** [d]	
	PV	EAV	PV	EAV	**PV**	**EAV**
Final Rules	270	14	120	6.30	390	21
Alternative 1	270	14	120	6.50	390	21
Alternative 2	250	13	120	6.30	370	20
	Climate Benefits Calculated using 2% Discount Rate, Health Benefits Calculated using 3% Discount Rate					
	Climate Benefits [b]		PM$_{2.5}$ and O$_3$-related Health Benefits [c]		**Total Benefits** [d]	
	PV	EAV	PV	EAV	**PV**	**EAV**
Final Rules	270	14	100	6.1	370	20
Alternative 1	270	14	110	6.2	370	20
Alternative 2	250	13	100	6.1	360	20
	Climate Benefits Calculated using 2% Discount Rate, Health Benefits Calculated using 7% Discount Rate					
	Climate Benefits [b]		PM$_{2.5}$ and O$_3$-related Health Benefits [c]		**Total Benefits** [d]	
	PV	EAV	PV	EAV	**PV**	**EAV**
Final Rules	270	14	59	5.2	330	19
Alternative 1	270	14	60	5.2	330	19
Alternative 2	250	13	58	5.1	310	19
Non-Monetized Benefits [d]						
Benefits from reductions in HAP emissions						
Benefits from improved water quality and availability						
Ecosystem benefits associated with reductions in emissions of CO$_2$, NO$_X$, SO$_2$, PM, and HAP						
Reductions in exposure to ambient NO$_2$ and SO$_2$						
Improved visibility (reduced haze) from PM$_{2.5}$ reductions						

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Monetized climate benefits are based on reductions in CO$_2$ emissions and are calculated using three different estimates of the social cost of CO$_2$ (SC-CO$_2$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO$_2$ at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[c] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in PM$_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[d] Several categories of climate, human health, and welfare benefits from CO$_2$, NO$_X$, SO$_2$, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO$_2$ and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

ES.7 Economic Impacts

As a result of the compliance costs incurred by the regulated sector, these final actions have economic and energy market implications. The energy impact estimates presented here reflect EPA's illustrative analysis of the final rules. States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Table ES-4 presents a variety of energy market impact estimates for 2028, 2030, 2035, 2040, and 2045 for the illustrative final rules scenario, relative to the baseline. These results are EPA's best estimate of possible compliance pathways with the final rules. However, there are several key areas of uncertainty inherent in these projections as outlined in Section 3.7.

Table ES-4 Summary of Certain Energy Market Impacts for the Illustrative Final Rules Scenario Relative to the Baseline

	2028	2030	2035	2040	2045
Retail electricity prices	-1%	0%	1%	0%	1%
Average price of coal delivered to the power sector	-1%	-1%	0%	0%	-32%
Coal production for power sector use	-6%	-4%	-21%	15%	-84%
Price of natural gas delivered to power sector	-2%	0%	3%	0%	0%
Price of average Henry Hub (spot)	-2%	-1%	3%	0%	0%
Natural gas use for electricity generation	-1%	-2%	4%	0%	2%

These and other energy market impacts are discussed more extensively in Section 3 of the RIA, and a more detailed version of the table is available in Section 5 of the RIA.

More broadly, changes in production in a directly regulated sector may have effects on other markets when output from that sector – for these final rules, electricity – is used as an input in the production of other goods. The final rules may affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as well as changes in household consumption patterns due to changes in the price of electricity and other final goods prices. Changes in firm and household behavior in response to the final rules could also interact with pre-existing distortions, such as taxes, resulting in additional social costs. Computable general equilibrium (CGE) models are analytical tools that can be used to evaluate the broad economy-wide impacts of a regulatory action and its social cost by including interactions and feedbacks between them. In response to a Science Advisory Board recommendation (U.S. EPA

Science Advisory Board, 2017), EPA developed a new CGE model for the U.S. economy called SAGE designed for use in regulatory analysis, which was peer reviewed (U.S. EPA Science Advisory Board, 2020).

EPA used SAGE to evaluate the economy-wide social costs and economic impacts of these final rules. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the finalized rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the finalized rules. We are not able to identify their relative roles at this time. The social cost estimates in the economy-wide analysis discussed in Section 5.2 are substantially lower than the projected benefits of the final rules. The economy-wide analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM. A detailed discussion of the social costs and distributional impacts of the final rules is contained in Section 5.2 of this RIA.[13]

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Employment impacts of these final actions are discussed more extensively in Section 5 of the RIA.

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[13] Section 5.2 also discusses the differences between social costs estimated by SAGE and the compliance costs estimated by IPM. For example, IPM estimates compliance costs incurred by firms in the electricity sector, but because of the availability of subsidy payments, there are additional real resource costs to the economy outside of the regulated sector. To estimate the social costs for the economy as a whole, EPA has used information from IPM as an input into SAGE. The economy-wide analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM.

ES.8 Environmental Justice Impacts

Environmental justice (EJ) concerns for each rulemaking are unique and should be considered on a case-by-case basis, and EPA's EJ Technical Guidance (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 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 and impacts. For the final rules, we quantitatively evaluate 1) the proximity of affected facilities to communities with EJ concerns for consideration of local pollutants impacted by these rules but not modeled here (Section 6.4), 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, life expectancy, redlining, Tribal land, age, sex, educational attainment, and degree of linguistic isolation (Section 6.5). While these analyses assess the distribution of non-climate impacts at more near-term and local spatial scales, we also discuss potential EJ climate impacts from projected long-term climate change (Section 6.3). Each of these analyses 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, such as local HAP, emitted from sources affected by the regulatory action for certain population groups of concern (Section 6.4). The baseline demographic proximity analyses examined the demographics of populations living within 5 km, 10 km, and 50 km of the following three sets of sources: 1) 114 coal plants with units subject to the 111 final rules, 2) 23 coal plants (a subset of the 114) with known retirement plans between 2033 and 2040, with units subject to the 111 final rules, and 3) 94 coal plants (a subset of the 114) without known retirement plans before 2040, with units subject to the final rules. See Section 6.4 regarding data limitations for the 5 km proximity analysis. The proximity analysis of the full population of potentially affected units greater than 25 MW (114 facilities) indicated that the demographic percentages of the population within 5 km and 10 km of the facilities are relatively similar to the national averages with the exception of the American Indian population (1 percent and 0.8 percent, respectively) that is higher than the national average (0.6 percent). This higher percentage is driven mostly by 7 facilities that have an American Indian percentage within a 5 km and 10 km radius that ranges from 10 percent to just over 40 percent which is substantially above the national average (0.6 percent). Also within a 5 km and 10 km radius, the population living below the federal poverty line (14 percent for both distances) as well as the population living below 2x the federal poverty line (34 percent and 33 percent, respectively) are both higher than the national averages (13 percent and 29 percent, respectively). The proximity analysis of the 23 units with known retirement plans between 2033 and 2040 (a subset of the total 114 units) found that the percentages of the population within 5 km and 10 km that is below the poverty line (14 percent for both distances) and below 2x the federal poverty line (33 percent and 31 percent, respectively) are both higher than the national averages (13 percent and 29 percent, respectively). The proximity analysis for the 94 units without known retirement plans before 2040 (a subset of the total 114 units) shows demographics similar to the 114 facilities' proximity analysis.

Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanic populations, Asian populations, those linguistically isolated, and those less educated will experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average (Section 6.5). Black populations will also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and American Indian populations and children will experience disproportionately higher ozone concentrations than the reference group. Therefore, there likely are potential EJ concerns for population groups of concern in the baseline.

Finally, we evaluate how these final rulemakings are expected to differentially impact demographic populations with regard to ozone and $PM_{2.5}$ exposure changes. Our analysis indicates that the final rules will secure modest widespread reductions in ozone and $PM_{2.5}$ pollution. Relative to 2028 baseline conditions, our analysis indicates that ozone and $PM_{2.5}$

concentrations will decline in virtually all areas of the country. However, some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ pollution over time as a result of the changes in generation and utilization resulting from the rule. In all years, the final rules are expected to result in reductions in ozone concentrations over many areas of the US, although some areas, in some analysis periods, may experience increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years. As a general rule, however, these changes in $PM_{2.5}$ and ozone concentrations are small (approximately 0.4 percent relative to the baseline) such that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action. This EJ assessment also suggests that this action is unlikely to mitigate or exacerbate $PM_{2.5}$ exposures disparities across populations of EJ concern analyzed. Regarding ozone exposures, the final rules will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated in most years; however, ozone exposure disparities may be slightly exacerbated for some population groups analyzed in 2035 and those living on Tribal lands in 2040, as well as slightly mitigated for those living on Tribal lands in 2028 and 2030.

ES.9 Comparison of Benefits and Costs

In this RIA, the regulatory impacts are evaluated for the specific snapshot years of 2028, 2030, 2035, 2040, and 2045, and MR&R costs are estimated for all years in the 2024 to 2047 timeframe. Comparisons of benefits to costs for the snapshot years of 2028, 2030, 2035, 2040, and 2045 are presented in Section 7 of this RIA. Here we present the PV and EAV of costs, benefits, and net benefits, calculated for the years 2024 to 2047 from the perspective of 2024, using the discount rates of two percent, three percent, and seven percent. All dollars are in 2019 dollars. The compliance cost estimates are net of changes in renewable energy, hydrogen, and CCS subsidies.

We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2024 to 2047, 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 reported in the costs and benefits sections of this RIA.

The comparison of benefits and costs in PV and EAV terms for the illustrative final rules scenario and alternative 1 and 2 scenarios can be found in Table ES-5. Estimates in the tables are presented as rounded values.

Table ES-5 Net Benefits of the Illustrative Scenarios (billions of 2019 dollars, discounted to 2024) [a]

All Values Calculated using 2% Discount Rate

	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Compliance Costs		Net Benefits [d]	
	PV	EAV	PV	EAV	PV	EAV	PV	EAV
Final Rules	270	14	120	6.3	19	0.98	370	20
Alternative 1	270	14	120	6.5	19	0.99	370	20
Alternative 2	250	13	120	6.3	19	0.98	360	19

Compliance Cost and Health Benefits Calculated using 3% Discount Rate, Climate Benefits Calculated using 2% Discount Rate

	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Compliance Costs		Net Benefits [d]	
	PV	EAV	PV	EAV	PV	EAV	PV	EAV
Final Rules	270	14	100	6.1	15	0.91	360	19
Alternative 1	270	14	110	6.2	16	0.93	360	19
Alternative 2	250	13	100	6.1	15	0.91	340	19

Compliance Cost and Health Benefits Calculated using 7% Discount Rate, Climate Benefits Calculated using 2% Discount Rate

	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Compliance Costs		Net Benefits [d]	
	PV	EAV	PV	EAV	PV	EAV	PV	EAV
Final Rules	270	14	59	5.2	7.5	0.65	320	19
Alternative 1	270	14	60	5.2	7.8	0.68	320	19
Alternative 2	250	13	58	5.1	7.2	0.63	310	18

Non-Monetized Benefits [e]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from $PM_{2.5}$ reductions

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[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[c] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[d] In this net benefits analysis, health benefits and costs are discounted at the rates shown in the table (i.e., two percent, three percent, and seven percent). Climate benefits are discounted using a two percent discount rate only in this net benefits analysis.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

As discussed in Section 4 of this RIA, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the final rules. In particular, the monetized climate benefits are incomplete and an underestimate as explained in Section 4.2. In addition, important health, welfare, and water quality benefits anticipated under these final rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the final rules to have greater benefit than the tables in this section reflect. Simultaneously, the estimates of compliance costs used in the net benefits analysis may provide an incomplete characterization of the social costs of the rule. See Section 5.2 for a discussion of why compliance costs from IPM may differ from social costs estimated in the SAGE model using a general equilibrium framework. The balance of unquantified benefits and costs is ambiguous but is unlikely to change the result that the benefits of the final rules exceed the costs by billions of dollars annually.

We also note that the RIA follows EPA's historical practice of using a detailed technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. In Section 5.2 of this RIA, EPA has also included an economy-wide analysis that considers additional facets of the economic response to the final rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies. The social cost estimates in the economy-wide analysis and discussed in Section 5.2 are still far below the projected benefits of the final rules.

ES.10 References

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1 INTRODUCTION AND BACKGROUND

1.1 Introduction

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare. [14] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[15] Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021.[16] At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources is available to the power sector—including carbon capture and sequestration/storage (CCS), co-firing with less GHG-intensive fuels, and more efficient generation. Congress has also acted to provide funding and other incentives to encourage the deployment of various technologies, including CCS, to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and new source performance standards (NSPS) that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Specifically, the EPA is first finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is

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[14] 74 FR 66496 (December 15, 2009).

[15] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

[16] https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines at this time and plans to expeditiously issue an additional proposal that more comprehensively addresses GHG emissions from this portion of the fleet. The EPA acknowledges that the share of GHG emissions from existing fossil fuel-fired combustion turbines has been growing and is projected to continue to do so, particularly as emissions from other portions of the fleet decline, and that it is vital to regulate the GHG emissions from these sources consistent with CAA section 111.

These final actions ensure that the new and existing fossil fuel-fired EGUs that are subject to these rules reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation’s overall need for a reliable supply of affordable electricity.

In accordance with Executive Order (E.O). 12866 and 13563, the guidelines of OMB Circular A-4 and EPA’s *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2014), the RIA analyzes the benefits and costs associated with the projected emissions reductions under the requirements of the final rules, and two alternative sets of requirements to inform EPA and the public about these projected impacts.[17]

We evaluated the potential impacts of the three illustrative scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024 to 2047, discounted to 2024. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These snapshot years are 2028, 2030, 2035, 2040 and 2045.

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[17] Circular A-4 was recently revised. The effective date of the revised Circular A-4 (2023) is March 1, 2024, for regulatory analyses received by OMB in support of proposed rules, interim final rules, and direct final rules, and January 1, 2025, for regulatory analyses received by OMB in support of other final rules. For all other rules, Circular A-4 (2003) is applicable until those dates.

1.2 Legal and Economic Basis for Rulemaking

In this section, we summarize the statutory requirements in the CAA that serve as the legal basis for the final rules and the economic theory that supports environmental regulation as a mechanism to enhance social welfare. The CAA requires EPA to prescribe regulations for new and existing sources of air pollution. In turn, those regulations attempt to address negative externalities created when private entities fail to internalize the social costs of air pollution.

1.2.1 Statutory Requirement

EPA's authority for and obligation to issue these final rules is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. This provision requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[18] EPA has listed more than 60 stationary source categories under this provision.[19] EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

Once EPA lists a source category, EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources (including modified and reconstructed sources) in the source categories.[20] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When EPA establishes NSPS for sources in a source category under CAA section 111(b), EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s

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[18] CAA §111(b)(1)(A).

[19] See 40 CFR 60 subparts Cb – OOOO.

[20] CAA §111(b)(1)(B), 111(a)(1).

mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.

"Standards of performance" are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." CAA section 111(d)(1) grants the authority, in applying a standard of performance, to take into account the source's remaining useful life and other factors.

Under CAA section 111(d), a state must submit its plan to EPA for approval, and EPA must approve the state plan if it is "satisfactory."[21] If a state does not submit a plan, or if EPA does not approve a state's plan, then EPA must establish a plan for that state.[22] Once a state receives EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act. See section V of the preamble to the final rules for more detailed statutory background and regulatory history for CAA Section 111.

1.2.1.1 Regulated Pollutant

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[23] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[24]

1.2.1.2 Definition of Affected Sources

These rules establish GHG mitigation measures on certain fossil fuel-fired electric generating units. For details on the source categories and the mitigation measures considered please see sections VII, VIII, and IX of the preamble.

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[21] CAA section 111(d)(2)(A).

[22] CAA section 111(d)(2)(A).

[23] 74 FR 66496 (December 15, 2009).

[24] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

1.2.2 The Need for Air Emissions 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 of one's action imposed on another party. For example, the smoke from a factory may adversely affect the health of exposed individuals and soil the property in nearby neighborhoods. For the final regulatory actions analyzed in this RIA, the good produced is electricity from fossil fuel-fired EGUs. If these electricity producers pollute the atmosphere when generating power, the social costs will not be borne exclusively by the polluting firm but rather by society as a whole. Thus, the producer is imposing a negative externality, or a social cost of emissions, on society. The equilibrium market price of electricity may fail to incorporate the full opportunity cost to society of these products. Consequently, absent a regulation on emissions, producers may not internalize the social cost of emissions and social costs will be higher as a result. The final rules will work towards addressing this market failure by causing affected producers to more fully internalize the negative externality associated with GHG emissions from electricity generation by new fossil fuel-fired combustion turbines and existing fossil fuel-fired steam-generating EGUs.

1.3 Overview of Regulatory Impact Analysis

1.3.1 Repeal of Affordable Clean Energy (ACE) Rule

Section VI of the preamble explains that EPA is repealing the Affordable Clean Energy (ACE) Rule. The RIA for the ACE Rule presented the projected impacts of an illustrative policy scenario that modeled heat rate improvements (HRI) at coal-fired EGUs (U.S. EPA, 2019). In the

ACE RIA, EPA projected the ACE Rule would have compliance costs in 2030 of about $280 million and CO_2 emissions reductions of about 11 million short tons in 2030.[25]

As explained in the preamble, EPA concludes based on new information including experience implementing the ACE Rule that the suite of HRI set forth in the rule, at best, would provide negligible CO_2 reductions. The ACE Rule's projected benefits were premised in part on a 2009 technical report by Sargent & Lundy that evaluated the effects of HRI technologies. In 2023, Sargent & Lundy issued an updated report which details that the HRI selected as the BSER in the ACE Rule would bring fewer emissions reductions than estimated in 2009.[26] The 2023 report concludes that, with few exceptions, HRI technologies are less effective at reducing CO_2 emissions than assumed in 2009. Also, most sources had already optimized application of HRI, and so there are fewer opportunities to reduce emissions than previously anticipated. Additionally, for a subset of sources, HRI are likely to cause a rebound effect leading to an increase in GHG emissions for those sources for the reasons explained in section X.D.5.a. of the preamble. The estimate of the rebound effect was quite pronounced in the ACE Rule's own analysis – the rule projected that it would increase CO_2 emissions from power plants in 15 states. Accordingly, EPA no longer believes that the suite of HRI the ACE Rule selected as the BSER is an appropriate BSER for existing coal-fired EGUs.

Consequently, EPA has determined it is appropriate to repeal the ACE Rule and to reevaluate whether other technologies constitute the BSER. EPA now concludes that different, more effective technologies like co-firing of natural gas and CCS are now cost reasonable for designated facilities with longer operating horizons. Since the ACE Rule was promulgated, changes in the power industry, developments in the costs of controls, and new federal subsidies have made these other more effective technologies more broadly available and less costly.

As noted in the ACE RIA, the ACE Rule itself required no specified degree of emission limitation or standards of performance. States were given only general criteria to inform their efforts to design standards for sources. After the ACE Rule was promulgated, early efforts at implementation of the rule underscored that the rule did not include enough specificity to ensure GHG reductions consistent with the RIA. Furthermore, even if we assumed the same degree of

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[25] In comparison, these final rules are projected to reduce approximately 50 million metric tons of CO_2 in 2030, and approximately 123 million metric tons of CO_2 in 2035 (see Table 3-5).

[26] See *Heat Rate Improvement Method Costs and Limitations Memo*, which is available in the docket for this action.

effectiveness as was assumed in the ACE Rule RIA, the number of units that would be covered if the ACE Rule were implemented today would be much lower because of declines in coal-fired generation since the ACE Rule was promulgated as well as increases in the number of facilities who have elected to commit to permanently cease operations in the coming years. Because of these factors, the expected costs and associated emissions changes of the ACE Rule are likely much less than projected in the 2019 ACE Rule RIA.[27]

Accordingly, based on reconsideration of the emissions impact of HRI and new information gained from early implementation of the ACE Rule, among other factors, EPA anticipates that the implementation of the ACE Rule would likely produce negligible, if any, change in costs or emissions relative to a world without the rule. In addition, the final 111(b) and 111(d) actions only occur after the repeal of the ACE Rule. As such, it is EPA's finding and conclusion that there is likely to be no difference in the baseline between a world where ACE is implemented and one where it is not.

1.3.2 Baseline and Analysis Years

The impacts of final regulatory actions are evaluated relative to a modeled baseline that represents expected behavior in the electricity sector under market and regulatory conditions in the absence of a regulatory action. EPA used the Integrated Planning Model (IPM)[28] to conduct the electric generating units (EGU) analysis discussed in this section, relying on the EPA's Power Sector Platform 2023 Using IPM to establish the baseline for this analysis. For a detailed description please see Section 3 of this document. EPA frequently updates the power sector modeling baseline to reflect the latest 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. The baseline includes the final Good Neighbor Plan (GNP), the Revised Cross-State Air Pollution Rule (CSAPR) Update, CSAPR Update, and CSAPR, as well as the 2012 Mercury and Air Toxics Standards. The power sector baseline also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the recently finalized

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[27] For details on historical coal retirements, please see the *Power Sector Trends – TSD* available in the docket for this rulemaking. For details on projected coal capacity under the baseline, please see Table 3-14.

[28] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.

2020 ELG and CCR rules. This version of the model ("EPA's Power Sector Platform 2023 using IPM 2022") also includes recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA). The modeling documentation, available in the docket, includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the model. Also, see Section 3 for additional detail about the power sector baseline for this RIA.

We evaluated the potential impacts of the three illustrative scenarios for the years 2024 to 2047 from the perspective of 2024, using discount rates of two percent, three percent, and seven percent. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These snapshot years are 2028, 2030, 2035, 2040, and 2045. The Agency believes that these specific years are each representative of several surrounding years, which enables the analysis of costs and benefits over the timeframe of 2024 to 2047. The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the regulatory impacts of the final 111(b) new source performance standards on the power sector will begin. However, because the Agency estimates that some monitoring, reporting, and recordkeeping (MR&R) costs may be incurred in 2024, we analyze compliance costs in years before 2028. Therefore, while MR&R costs analysis is presented beginning in the year 2024, the detailed assessment of costs, emissions impacts, and benefits begins in the year 2028. The analysis timeframe concludes in 2047, as this is the last year that may be represented with the analysis conducted for the specific year of 2045.

1.3.3 Best System of Emission Reduction (BSER)

These final actions include the repeal of the ACE Rule, BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, and BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired steam generating units. See Section I.C of the final rule preamble for a summary of the major provisions of these regulations. Related information can also be found in Technical Support Documents (TSDs) available in the rulemaking docket.

1.3.4 Illustrative Scenarios

This RIA evaluates the potential benefits, costs, and other impacts associated with compliance actions projected under three illustrative scenarios: one scenario representing the final rules, and two scenarios representing alternative sets of requirements. The modeling of the illustrative final rules scenario that is discussed in Sections 3 through 7 of this RIA includes the final 111(b) requirements for new and reconstructed stationary combustion turbines and final 111(d) requirements for existing fossil fuel-fired steam generating units.

The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA. See Section 3.4 for further discussion of the modeling approach used in the analysis presented below. For details of the controls modeled for each of the existing source categories starting in run year 2030 under the three illustrative scenarios please see Section 3.2 of this document.

1.4 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining sections:

- **Section 2: Industry Profile**. This section describes the electric power sector in detail.
- **Section 3: Cost, Emissions, and Energy Impacts**. This section summarizes the projected compliance costs and other energy impacts associated with the regulatory options.
- **Section 4: Benefits Analysis**. This section presents the projected climate benefits of CO_2 emissions reductions, and the health and environmental benefits of reductions in emissions of nitrogen oxides (NO_X), fine particulate matter ($PM_{2.5}$) and sulfur dioxide (SO_2). Potential benefits to drinking water quality and quantity are also discussed.

- **Section 5: Social Costs and Economic Impacts**. This section includes a discussion of energy market impacts, economy-wide social costs and economic impacts, potential small entity impacts, and labor impacts.
- **Section 6: Environmental Justice Impacts**. This section includes an assessment of potential impacts to potential EJ populations.
- **Section 7: Comparison of Benefits and Costs**. This section compares the total projected benefits with total projected costs and summarizes the projected net benefits of the three illustrative scenarios examined. The section also includes a discussion of potential benefits that EPA is unable to quantify and monetize.
- **Appendix A: Climate Benefits.** This section presents the climate benefits of the final standards using the interim SC-CO_2 values used in the proposals of these rulemakings.
- **Appendix B: Air Quality Modeling**. This section describes the air quality modeling simulations, provides details on the methodology to apply the air quality modeling to estimate ozone and $PM_{2.5}$ impacts of the illustrative final rules scenario and presents resulting surfaces that represent air quality changes associated with the illustrative scenarios.
- **Appendix C: Environmental Justice Analysis**. This section presents additional figures associated with the alternative 1 scenario and alternative 2 scenario.
- **Appendix D: Assessment of Potential Costs and Emissions Impacts of Final New and Existing Source Standards Analyzed Separately.** This section summarizes the projected compliance costs and other energy impacts associated with the imposition of new source standards independently from existing source standards.

1.5 References

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2 INDUSTRY PROFILE

2.1 Background

In the past decade, there have been substantial 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 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 from renewable energy sources. Many of these trends will likely continue to contribute to the evolution of the power sector.[29] 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 to produce both base and peak load electricity. Additionally, rapid growth in the deployment of wind and solar technologies has led to their now constituting a significant share of generation. The combination of these factors has led to a decline in the share of electricity generated from coal.[30] This section presents data on the evolution of the power sector over the past two decades from 2010 through 2022, as well as a focus on the period 2015 through 2022. Projections of future power sector behavior and the impact of the final rules are discussed in more detail in Section 3 of this RIA.

2.2 Power Sector Overview

The production and delivery of electricity to customers relies on of three distinct stages: the generation, transmission, and distribution of electricity.

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*

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[29] For details on the evolution of EPA's power sector projections, please see archive of IPM outputs available at: epa.gov/power-sector-modeling

[30] For details, please see "Power Sector Trends Technical Support Document" available in the docket for this rulemaking.

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. Units are also unavailable during routine and unanticipated outages for maintenance. 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. These factors result in the share of potential generating capacity being substantially different from the share of actual 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 combustion 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 most common 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 in 2010 to 2022 and 2015 to 2022.

In 2022 the power sector comprised a total capacity[31] of 1,201 GW, an increase of 162 GW (or 16 percent) from the capacity in 2010 (1,039 GW). The largest change over this period was the decline of 127 GW of coal capacity, reflecting the retirement/rerating of close to 40 percent of the coal fleet. This reduction in coal capacity was offset by increases in natural gas, solar, and wind capacities of 95 GW, 72 GW, and 102 GW respectively. Substantial amounts of distributed solar (40 GW) were also added.

These trends persist over the shorter 2015-21 period as well; total capacity in 2022 (1,201 GW) increased by 127 GW (or 12 percent). The largest change in capacity was driven by a reduction of 90 GW of coal capacity. This was offset by a net increase of 63 GW of natural gas capacity, an increase of 69 GW of wind, and an increase of 59 GW of solar. Additionally, 30 GW of distributed solar were also added over 2015-22.

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[31] 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 section (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).

Table 2-1 Total Net Summer Electricity Generating Capacity by Energy Source, 2010-22 and 2015-22

	2010		2022		Change Between '10 and '22	
Energy Source	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**
Coal	317	30%	189	16%	-40%	-127
Natural Gas	407	39%	502	42%	23%	95
Nuclear	101	10%	95	8%	-6%	-7
Hydro	101	10%	103	9%	2%	2
Petroleum	56	5%	31	3%	-45%	-25
Wind	39	4%	141	12%	261%	102
Solar	1	0%	73	6%	8310%	72
Distributed Solar	0	0%	40	3%		40
Other Renewable	14	1%	15	1%	7%	1
Misc	4	0%	12	1%	239%	9
Total	1,039	100%	1,201	100%	16%	162

	2015		2022		Change Between '15 and '22	
Energy Source	**Net Summer Capacity (GW)**	**% Total Capacity**	**Net Summer Capacity (GW)**	**% Total Capacity**	**% Increase**	**Capacity Change (GW)**
Coal	280	26%	189	16%	-32%	-90
Natural Gas	439	41%	502	42%	14%	63
Nuclear	99	9%	95	8%	-4%	-4
Hydro	102	10%	103	9%	1%	1
Petroleum	37	3%	31	3%	-16%	-6
Wind	73	7%	141	12%	95%	69
Solar	14	1%	73	6%	433%	59
Distributed Solar	10	1%	40	3%	307%	30
Other Renewable	17	2%	15	1%	-11%	-2
Misc	4	0%	12	1%	182%	8
Total	1,074	100%	1,201	100%	12%	127

Source: EIA. Electric Power Annual 2020 and 2022, Table 4.2.A and 4.2.B

The average age of coal-fired power plants that retired between 2015 and 2023 was 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.[32] As shown in Figure 2-1 below, 70 percent of the coal fleet in 2023 had an average age of over 40 years.

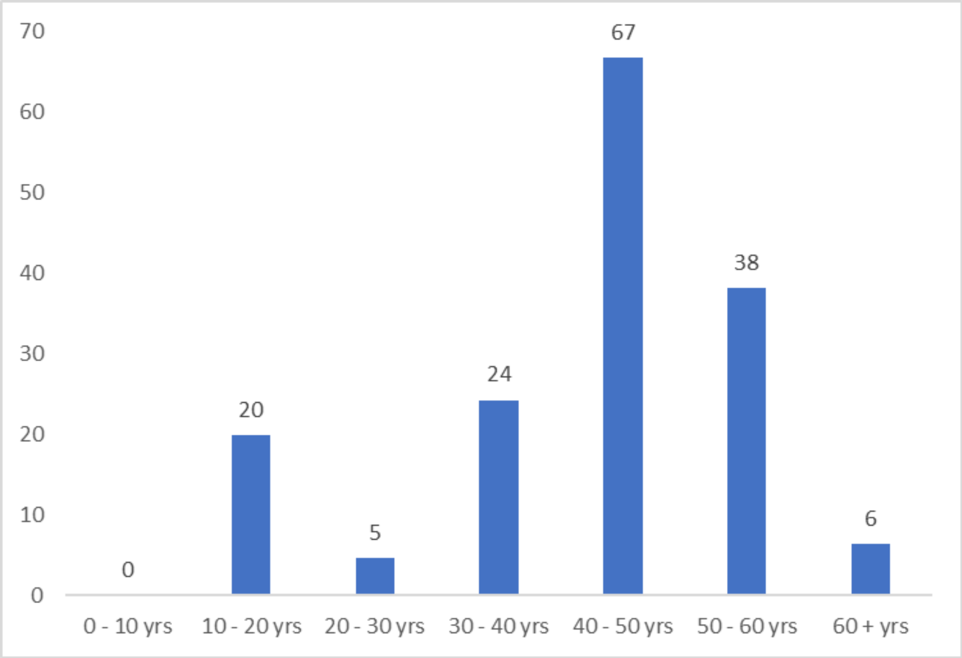

Figure 2-1 National Coal-fired Capacity (GW) by Age of EGU, 2023
Source: NEEDS v7

In 2022, electric generating sources produced a net 4,292 TWh to meet national electricity demand, which was around 4 percent higher than 2010. As presented in Table 2-2, 60 percent of electricity in 2022 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 2022 (60 percent) was 10 percent less than the share in 2010 (70 percent). Moreover, the share of fossil generation supplied by coal fell from 65 percent in 2010 to 33 percent by 2022, while the share of fossil generation supplied by natural gas rose from 35 percent to 67 percent over the same period. In absolute terms, coal generation declined by 55 percent, while natural gas generation increased by 71 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and

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

existing gas EGUs during that period. The combination of wind and solar generation also grew from 2 percent of the mix in 2010 to 14 percent in 2022.

Table 2-2 Net Generation by Energy Source, 2010 - 22 and 2015 - 22 (Trillion kWh = TWh)

	2010		2022		Change Between '10 and '22	
Energy Source	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**% Increase**	**Generation Change (TWh)**
Coal	1,847	45%	832	19%	-55%	-1,016
Natural Gas	988	24%	1,687	39%	71%	699
Nuclear	807	20%	772	18%	-4%	-35
Hydro	255	6%	249	6%	-2%	-6
Petroleum	37	1%	23	1%	-38%	-14
Wind	95	2%	434	10%	359%	340
Solar	1	0%	144	3%	11764%	143
Distributed Solar	0	0%	61	1%		61
Other Renewable	71	2%	68	2%	-5%	-3
Misc	24	1%	23	1%	-6%	-1
Total	4,125	100%	4,292	100%	4%	167

Table 2-3 Net Generation in 2015 and 2022 (Trillion kWh = TWh)

	2015		2022		Change Between ’15 and ‘22	
Energy Source	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**% Increase**	**Generation Change (TWh)**
Coal	1,352	33%	832	19%	-39%	-521
Natural Gas	1,335	33%	1,687	39%	27%	354
Nuclear	797	19%	772	18%	-3%	-26
Hydro	244	6%	249	6%	2%	5
Petroleum	28	1%	23	1%	-19%	-5
Wind	191	5%	434	10%	128%	244
Solar	25	1%	144	3%	478%	119
Distributed Solar	14	0%	61	1%	333%	47
Other Renewable	80	2%	68	2%	-15%	-12
Misc	27	1%	23	1%	-16%	-4
Total	4,092	100%	4,292	100%	5%	200

Source: EIA. Electric Power Annual 2020 and 2022, Table 3.1.A and 3.1.B

Coal-fired and nuclear generating units have historically supplied “base load” electricity, meaning that these units operate through most hours of the year and serve the portion of electricity load that is continually present. Although much of the coal fleet has historically operated as base load, there can be notable differences in the design of various facilities (see Table 2-3) which, along with relative fuel prices, can impact the operation of coal-fired power plants. As one example of design variations, coal-fired units less than 100 megawatts (MW) in size comprise 17 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity, and they tend to have higher heat rates. Gas-fired generation is generally better able to vary output, is a 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. Over the last decade, however, the generally low price of natural gas and the growing age of the coal fleet has resulted in increasing capacity factors for many gas-fired plants and decreasing capacity factors for many coal-fired plants. As shown in Figure 2-2, average annual coal capacity factors have declined from 67 percent to 50 percent over the 2010 to 2022 period, indicating that a larger share of units are operating in non-baseload fashion. Over the same period, natural gas combined cycle capacity factors have risen from an annual average of 44 percent to 57 percent.

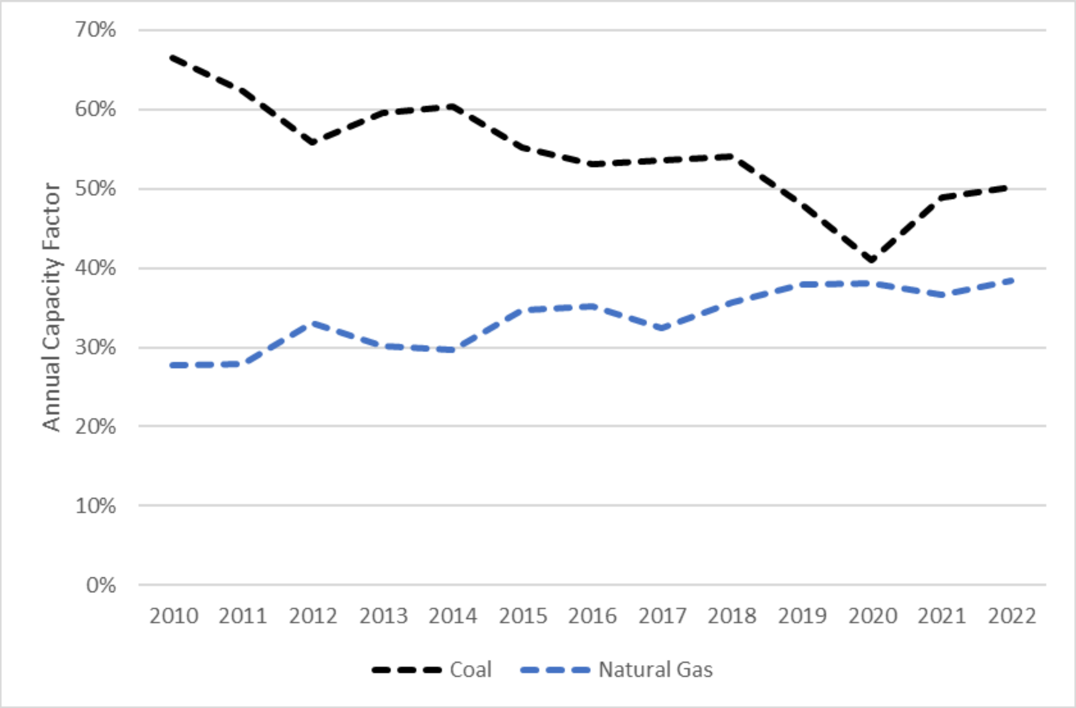

Figure 2-2 Average Annual Capacity Factor by Energy Source
Source: EIA. Electric Power Annual 2020 and 2022, Table 4.8.A

Table 2-4 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 69 percent of the coal EGU fleet capacity is over 500 MW per unit, 82 percent of the gas fleet is between 50 and 500 MW per unit.

Table 2-4 Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2023

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	23	5%	54	12	266	0%	11,174
25 – 49	32	7%	37	35	1,124	1%	11,541
50 – 99	23	5%	35	75	1,720	1%	11,807
100 – 149	28	6%	54	121	3,397	2%	11,198
150 – 249	50	11%	51	193	9,643	5%	10,844
250 – 499	110	25%	43	373	40,997	22%	10,674
500 – 749	122	27%	42	605	73,849	40%	10,298
750 – 999	50	11%	40	824	41,221	22%	10,158
1000 – 1500	10	2%	46	1,261	12,611	7%	9,841
Total Coal	448	100%	45	413	184,828	100%	10,693
NATURAL GAS							
0 – 24	4,679	56%	30	4	20,963	4%	13,006
25 – 49	899	11%	26	41	36,619	7%	11,545
50 – 99	1,000	12%	29	72	71,611	14%	12,194
100 – 149	391	5%	26	125	48,863	10%	9,548
150 – 249	1,037	12%	20	180	186,503	37%	8,194
250 – 499	309	4%	21	330	101,969	20%	8,072
500 – 749	47	1%	30	585	27,495	5%	9,374
750 – 999	8	0%	47	838	6,706	1%	11,366
1000 – 1500	0	0%			0	0%	
Total Gas	8,362	100%	27	60	500,730	100%	11,790

Source: National Electric Energy Data System (NEEDS) v.7
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 69 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 81 percent of the natural gas capacity has been in service less than 40 years. Figure 2-3 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 2-3 also includes the distribution of generation, which is similar to the distribution of capacity.

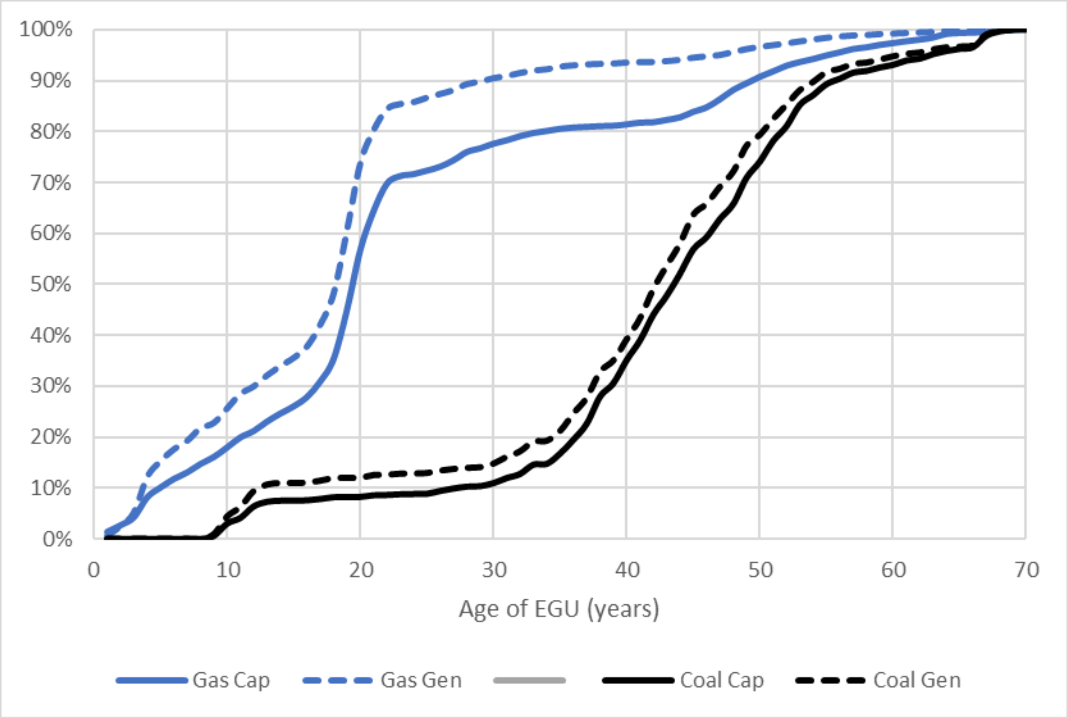

Figure 2-3 Cumulative Distribution in 2021 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: eGRID 2021 (November 2023 release from EPA eGRID website). Figure presents data from generators that came online between 1950 and 2021 (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 2-4.

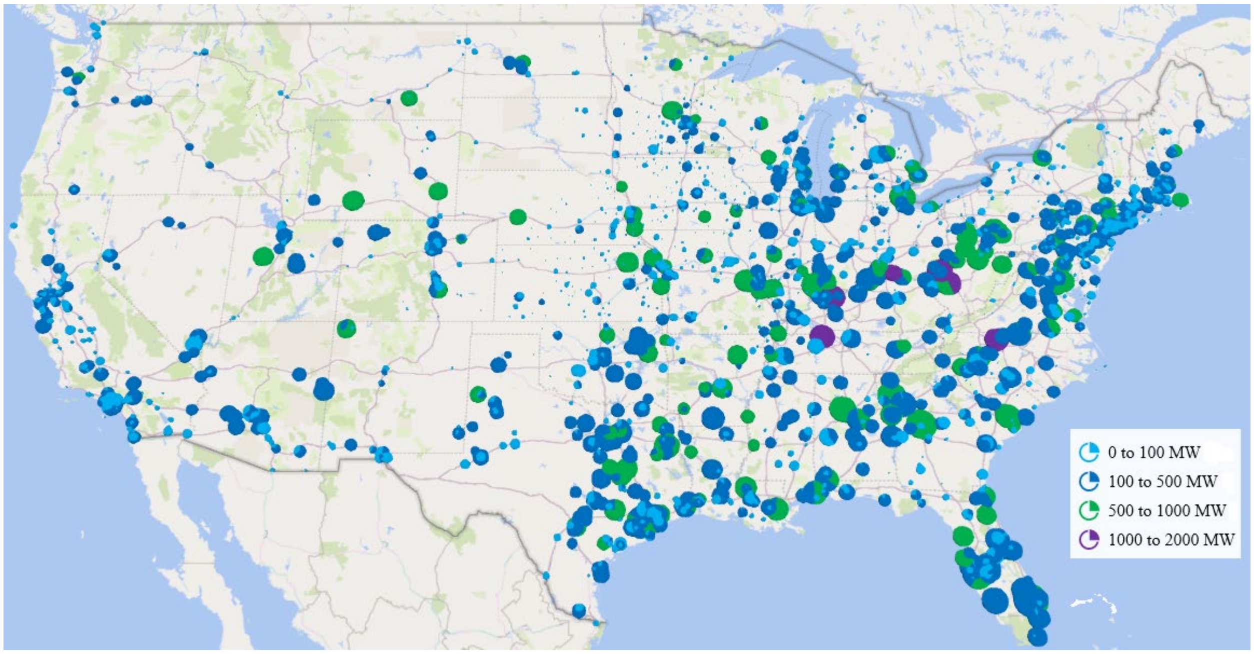

Figure 2-4 Fossil Fuel-Fired Electricity Generating Facilities, by Size
Source: National Electric Energy Data System (NEEDS) v.6
Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2023. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

The costs of renewable generation have fallen significantly due to technological advances, improvements in performance, and local, state, and federal incentives such as the recent extension of federal tax credits. According to Lazard, a financial advisory and asset management firm, the current unsubsidized levelized cost of electricity for wind and solar energy technologies is lower than the cost of technologies like coal, natural gas or nuclear, and in some cases even lower than just the operating cost, which is expected to lead to ongoing and significant deployment of renewable energy. Levelized cost of electricity is only one metric used to compare the cost of different generating technologies. It contains a number of uncertainties including utilization and regional factors.[33] While this chart illustrates general trends, unit specific build decisions will incorporate many other variables. These trends of declining costs and cost projections for renewable resources are borne out by a range of other studies including the NREL Annual Technology Baseline[34], DOE's Land-Based Wind Market Report[35], LBNL's

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[33] Lazard, Levelized Cost of Energy Analysis-Version 16.0, 2023. https://www.lazard.com/media/typdgxmm/lazards-lcoeplus-april-2023.pdf
[34] Available at: https://atb.nrel.gov/
[35] Available at: https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition

Utility Scale solar report[36], EIA's Annual Energy Outlook[37], and DOE's 2022 Grid Energy Storage Technology Cost and Performance Assessment.[38]

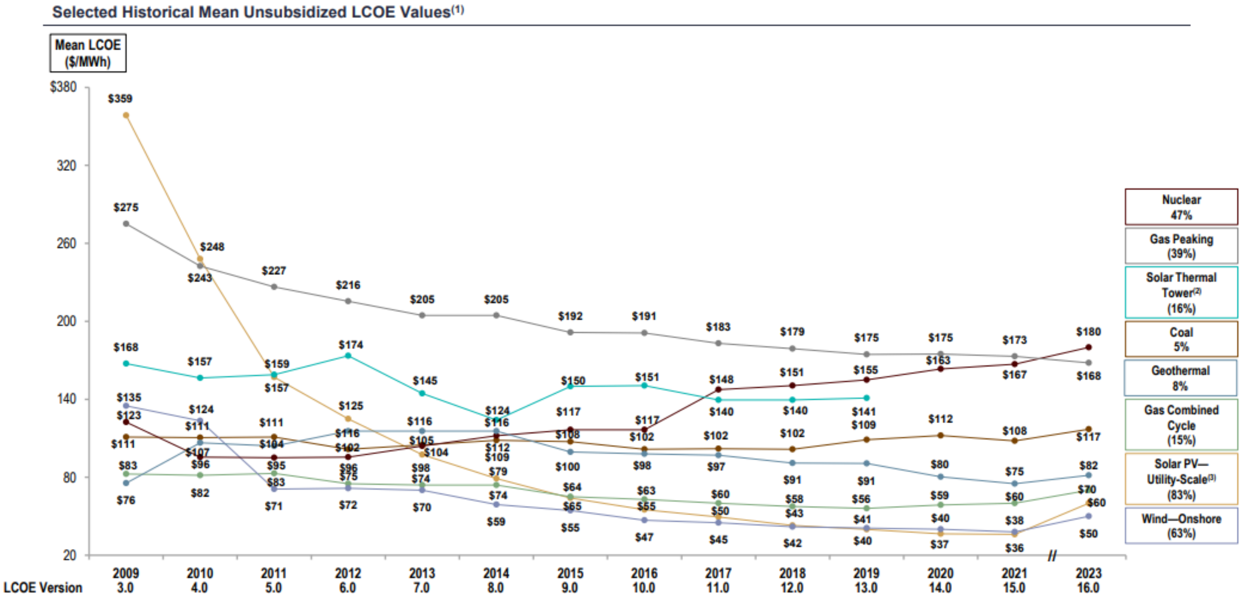

Figure 2-5 Selected Historical Mean LCOE Values
Source: Lazard, Levelized Cost of Energy Analysis-Version 16.0, April 2023
Notes: (1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE v3.0. (2) The LCOE no longer analyzes solar thermal costs; percent decrease is as of Lazard's LCOE v13.0. (3) Prior versions of Lazard's LCOE divided Utility-Scale Solar PV into Thin Film and Crystalline subcategories. All values before Lazard's LCOE v16.0 reflect those of the Solar PV—Crystalline technology.

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and recently announced plans of many power plants across the industry — spanning all types of companies in all locations. Furthermore, as detailed below, many utilities have made commitments to move toward cleaner energy. Throughout the country, utilities have included commitments towards cleaner energy in public releases, planning documents, and integrated resource plans (IRPs). For strategic business reasons and driven by the economics of different supply options, many major utilities plan to increase their renewable energy holdings and continue reducing GHG emissions, regardless of what federal regulatory requirements might exist. The Edison Electric Institute (EEI) has confirmed these developments: "While the CPP was stayed by the Supreme Court in 2016, the power sector will have complied

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[36] Available at: https://emp.lbl.gov/utility-scale-solar/

[37] Available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[38] Available at: https://www.energy.gov/eere/analysis/2022-grid-energy-storage-technology-cost-and-performance-assessment

with the final 2030 goals of the rule—in terms of gross emissions reductions—before the 2022 start date included in that program."[39] This trend is not unique to the largest owner-operators of coal-fired generation; smaller utilities, public power, cooperatives, and municipal entities are also contributing to these changes.

While EPA does not account for future planning statements from utility providers in the economic modeling since they are not legally enforceable, the number and scale of these announcements is significant on a systemic level. These statements are part of long-term planning processes that cannot be easily revoked due to considerable stakeholder involvement in the planning process, including the involvement of regulators. The direction to which these utility providers have publicly stated they are moving is consistent across the sector and undergirded by market fundamentals lending economic credibility to these commitments and confidence that that most plans will be implemented.

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,[40] 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;[41] in others, individual utilities[42] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

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[39] EEI Comments on ACE, at 4 (Oct. 31, 2018)

[40] These three network interconnections are the Western Interconnection, comprising the western parts of the U.S. and Canada, the Eastern Interconnection, comprising the eastern parts of the U.S. and Canada except parts of eastern Canada in the Quebec Interconnection, and the Texas Interconnection, encompassing 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*.

[41] For example, PJM Interconnection, LLC., New York Independent System Operator (NYISO), Midwest Independent System Operator (MISO), California Independent System Operator (CAISO), *etc.*

[42] For example, Los Angeles Department of Water and Power, Florida Power and Light. *etc.*

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. 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

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 (see Table 2-5). [43] Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are

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

relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2010 and 2022.

Table 2-5 Total U.S. Electric Power Industry Retail Sales, 2010-22 and 2014-22 (billion kWh)

		2010		2022	
		Sales/Direct Use (Billion kWh)	Share of Total End Use	Sales/Direct Use (Billion kWh)	Share of Total End Use
Sales	Residential	1,446	37%	1,509	37%
	Commercial	1,330	34%	1,391	34%
	Industrial	971	25%	1,020	25%
	Transportation	8	0%	7	0%
Total		3,755	97%	3,927	97%
Direct Use			132		140
Total End Use			**3,887**		**4,067**
		2015		**2022**	
		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%	1,509	37%
	Commercial	1,361	35%	1,391	34%
	Industrial	987	25%	1,020	25%
	Transportation	8	0%	7	0%
Total		3,759	96%	3,927	97%
Direct Use			141		140
Total End Use			**3,900**		**4,067**

Source: Table 2.2, EIA Electric Power Annual, 2020 and 2022 (October 19 2023 release)
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 of the extensive distribution network reaching to virtually every building in every part of the country and the fact that generating stations are increasingly located relatively far from population centers, increasing 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 have historically 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 2022, the national average retail electricity price (all sectors) was 12.4 cents/kWh, with a range from 8.2 cents (Wyoming) to 39.72 cents (Hawaii).[44]

The real year prices for 2010 through 2022 are shown in Figure 2-6. Average national retail electricity prices decreased between 2010 and 2022 by 4 percent in real terms (2022 dollars), and 2 percent between 2015-22.[45] The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average commercial prices decreased the most (4 percent), and industrial prices decreased the least (1 percent) between 2015-21.

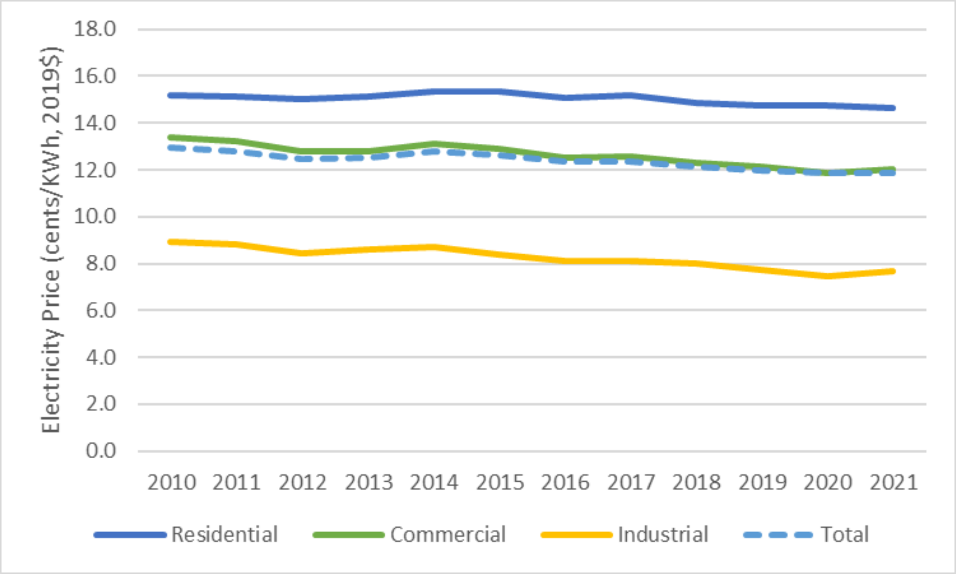

Figure 2-6 Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories

Source: EIA. Electric Power Annual 2020 and 2022, Table 2.4.

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[44] EIA State Electricity Profiles with Data for 2022 (http://www.eia.gov/electricity/state/)

[45] All prices in this section are estimated as real 2022 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

2.3.2 Prices of Fossil Fuel Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in delivered fuel prices[46] for the three major fossil fuels used in electricity generation: coal, natural gas, and petroleum products. Relative to real prices in 2015, the national average real price (in 2022 dollars) of coal delivered to EGUs in 2022 had decreased by 12 percent, while the real price of natural gas increased by 84 percent. The real price of delivered petroleum products also increased by 102 percent, and petroleum products declined as an EGU fuel (in 2022 petroleum products generated 1 percent of electricity). The combined real delivered price of all fossil fuels (weighted by heat input) in 2022 increased by 62 percent over 2015 prices. Figure 2-7 shows the relative changes in real price of all 3 fossil fuels between 2010 and 2022.

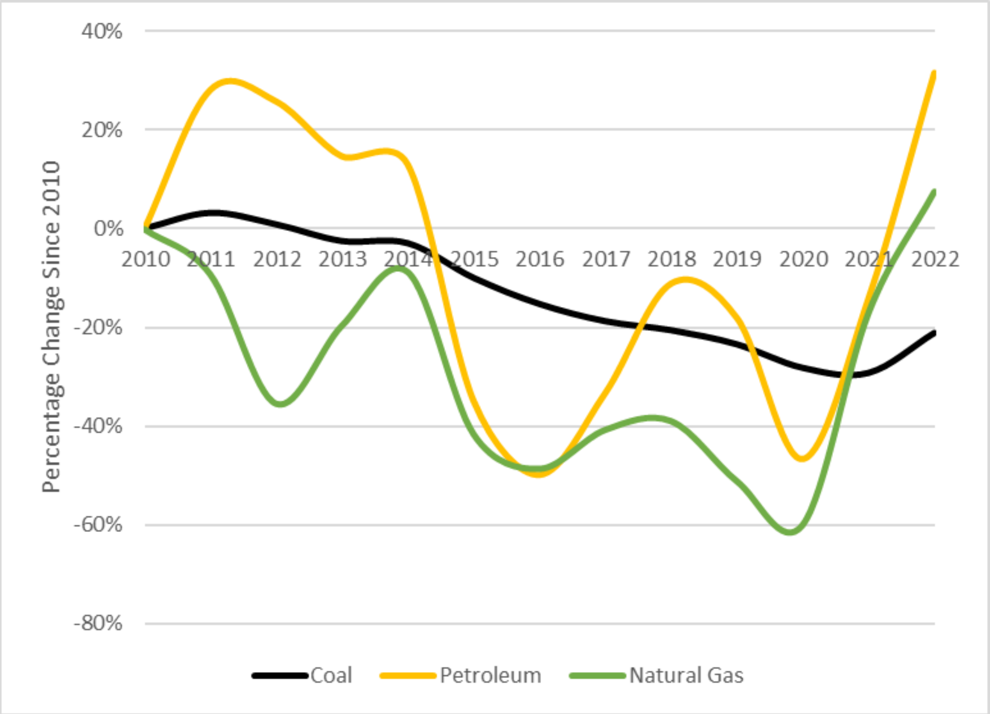

Figure 2-7 Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU

Source: EIA. Electric Power Annual 2021 and 2022, Table 7.1.

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

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2010 to 2022

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2010 and 2022 is that while total net generation increased by 4 percent over that period, the demand growth for generation was lower than both the population growth (8 percent) and real GDP growth (30 percent). Figure 2-8 shows the growth of electricity generation, population, and real GDP during this period.

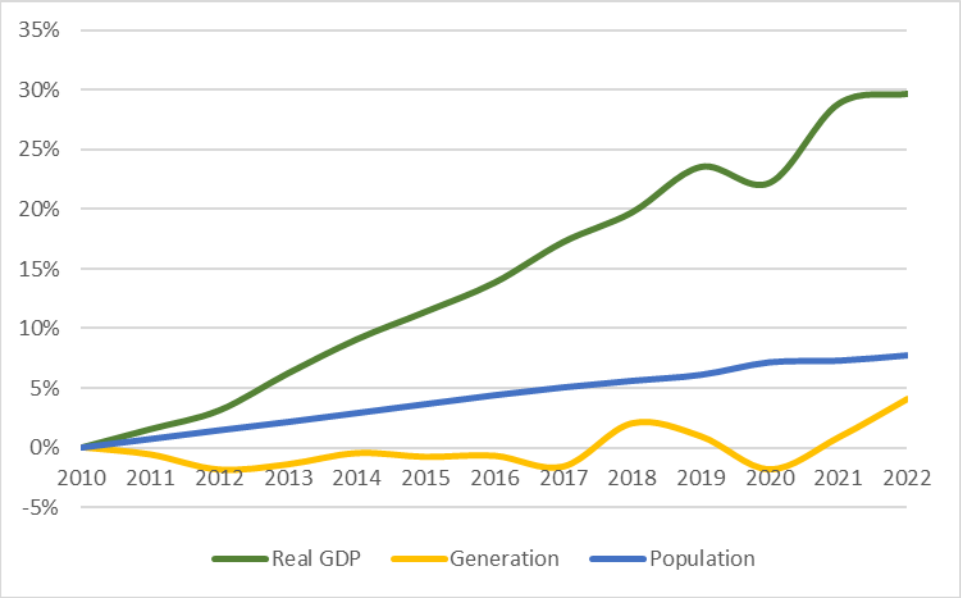

Figure 2-8 Relative Growth of Electricity Generation, Population and Real GDP Since 2010

Sources: Generation: U.S. EIA Electric Power Annual 2021 and 2022. Population: U.S. Census. Real GDP: U.S. Bureau of Economic Analysis

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 2022. On a per capita basis, real GDP per capita grew by 20 percent between 2010 and 2022. At the same time electricity generation per capita decreased by 3 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 20 percent. These relative changes are shown in Figure 2-9.

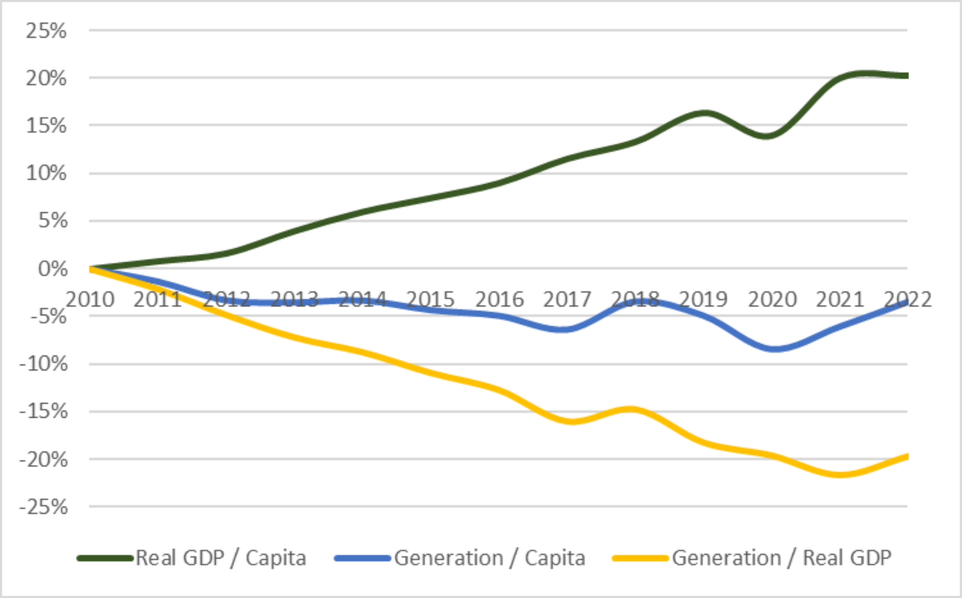

Figure 2-9 Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2010

Sources: Generation: U.S. EIA Electric Power Annual 2020 and 2022. Population: U.S. Census. Real GDP: U.S. Bureau of Economic Analysis

3 COMPLIANCE COSTS, EMISSIONS, AND ENERGY IMPACTS

3.1 Overview

This section reports the compliance costs, emissions, and energy analyses performed for the final NSPS and final Emission Guidelines. EPA used the Integrated Planning Model (IPM)[47] to conduct the electric generating units (EGU) analysis discussed in this section. As explained in detail below, this section presents analysis for three illustrative scenarios that differ in the level of EGU greenhouse gas (GHG) mitigation measures, and timing thereof in the lower 48 states subject to this action. The analysis for EGUs in the section includes effects from certain provisions of the Inflation Reduction Act (IRA) of 2022 in the baseline.[48] The analysis presented in this section reflects the combined effects of the final rules on new and existing sources. The impacts of each action independently are presented in Appendix D.

The section is organized as follows: following a summary of the illustrative scenarios analyzed and a summary of 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 select run years.[49]

3.2 Illustrative Scenarios

These rules establish GHG mitigation measures on certain fossil fuel-fired electric generating units. The EGUs covered by these rules are existing fossil fuel-fired steam generating

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[47] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.

[48] The Inflation Reduction Act (IRA) contains tax credit provisions that affect power sector operations, details of which are incorporated into the IPM modeling. Details are included in the IPM documentation. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4. Documentation available at: https://www.epa.gov/power-sector-modeling

[49] 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. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. For this analysis, IPM maps the calendar year 2028 to run year 2028, calendar years 2029-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-42 to run year 2040, calendar years 2043-47 to run year 2045 and calendar years 2048-52 to run year 2050. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling

units greater than 25 MW, and new and reconstructed fossil fuel-fired combustion turbines that commence construction or reconstruction after the publication of this final regulation. For details on the source categories and the mitigation measures considered please see sections VII, VIII, and IX of the preamble.

This RIA evaluates the benefits, costs, and certain impacts of compliance with three illustrative scenarios: one scenario representing the final rules, and two scenarios representing alternative sets of requirements. To the extent possible, EPA evaluated the 111(b) final rule for new natural-gas fired EGUs and 111(d) final rule for existing coal fired EGUs in combination to better analyze the interactive effects of the final rules. For details of the controls modeled for each of the existing source categories starting in run year 2030 under the three illustrative scenarios please see Table 3-1 and Table 3-2 below.

Table 3-1 Summary of Modeled GHG Mitigation Measures for Existing Sources by Source Category under the Illustrative Final Rules and Alternative 1 Scenario[a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.

[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.

[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table 3-2 Summary of Modeled GHG Mitigation Measures for Existing Sources by Source Category under the Illustrative Alternative 2 Scenario[a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035 but have committed to permanently ceasing operations by 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2035

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.

[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.

[c] Coal-fired EGUs that convert entirely to burn natural gas by 2035 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table 3-3 Summary of GHG Mitigation Measures for New Sources by Source Category under the Illustrative Final Rules, Alternative 1 and Alternative 2 Scenarios[a,b]

Affected EGUs	Subcategory Definition	Modeled Requirements During 1st Phase	Modeled Requirements During 2nd Phase (2035)	Baseload Definition: Alternative 1 and Alternative 2 Scenarios	Baseload Definition: Final Rules Scenario
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at greater than baseload annual capacity factor	Efficient generation	CCS or co-fire hydrogen at sufficient level to meet CCS emission rate	50%	40%
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than baseload	Efficient generation			
Intermediate load Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of more than 20%	Emission rate consistent with NGCC operation			
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 20%	Efficient generation			

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.

[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.

[c] The modeling does not reflect the requirements of the variable subcategory. We estimate this would have a limited impact on the results.

The illustrative compliance outcomes in this RIA represent EGU behavior in response to GHG mitigation measures applied to affected source categories in given IPM run years.[50] This RIA analyzes the final rules, as well as two alternative scenarios. The alternative 1 and alternative 2 scenarios assume the definition of annual capacity factor for baseload operation for new turbines is 50 percent, whereas under the final rules scenario baseload is defined as 40 percent annual capacity factor. The final rules and alternative 1 scenarios assume all medium-term existing coal-fired steam generating units must co-fire at least 40 percent natural gas by 2030[51], while the alternative 2 scenario assumes that all medium-term existing coal fired steam generating units must co-fire at least 40 percent natural gas by 2035.

The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA. See Section 3.4 for further discussion of the modeling approach used in the analysis presented below.

3.3 Monitoring, Reporting, and Recordkeeping Costs

EPA projected monitoring, reporting and recordkeeping (MR&R) costs for both state entities and affected EGUs for the years 2024 onwards. The MR&R cost estimates presented below apply to the three illustrative scenarios.

EPA estimates that industry will incur MR&R costs due to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units. More specifically, we estimate costs associated with 40 CFR

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[50] 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. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. For this analysis, IPM maps the calendar year 2028 to run year 2028, calendar years 2029-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-42 to run year 2040, calendar years 2043-47 to run year 2045 and calendar years 2048-52 to run year 2050. For model details, please see Chapter 2 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling

[51] CCS costs used in this analysis are developed by Sargent & Lundy and are outlined in Chapter 6 of the IPM documentation. These costs do not include the solvent acid or water washing costs. For details, please see: https://www.epa.gov/power-sector-modeling.

Part 60, Subpart TTTTa, as described in the supporting statement found in the docket. For purposes of RIA analysis, we assume that national costs in 2026 are approximately $35,000 in 2019 dollars, and then increase by approximately $35,000 in 2019 dollars each year thereafter to reflect costs associated with additional respondents.[52] We estimate that states will not incur MR&R costs associated with the Final New Source Performance Standards.

EPA estimates that industry will not incur incremental MR&R costs due to the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units. We estimate that states will incur MR&R costs associated with this final rule. We estimate that this may affect 43 states, resulting in a total national annual burden of approximately 89,400 hours of labor, or approximately $11 million in 2019 dollars. For detailed information, see the Information Collection Request Support Statement for the Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units available in the docket for these actions. For purposes of this analysis, we estimate that these MR&R costs will be incurred over the three-year period of 2024 through 2026.

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[52] For purposes of this regulatory impact analysis: (1) As described in the TTTTa supporting statement in the docket, we estimate there to be six new respondents in 2026; (2) We assume that these six respondents are simple cycle units, and that NGCC units would not incur MR&R costs incremental to existing TTTT requirements; (3) We assume that the number of new respondents would increase by six new respondents per year for each year over this analysis timeframe through 2047.

Table 3-4 Summary of State and Industry Annual Respondent Cost of Reporting and Recordkeeping Requirements (million 2019 dollars)

	Final NSPS for New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units		Final EGs for Existing Fossil Fuel-Fired Electric Generating Units		Total
	Industry	State[a]	Industry[b]	State	Total
2024	-	-	-	11	11
2025	-	-	-	11	11
2026	0.035	-	-	11	11
2027	0.07	-	-	-	0.070
2028	0.11	-	-	-	0.11
2029	0.14	-	-	-	0.14
2030	0.18	-	-	-	0.18
2031	0.21	-	-	-	0.21
2032	0.25	-	-	-	0.25
2033	0.28	-	-	-	0.28
2034	0.32	-	-	-	0.32
2035	0.35	-	-	-	0.35
2036	0.39	-	-	-	0.39
2037	0.42	-	-	-	0.42
2038	0.46	-	-	-	0.46
2039	0.49	-	-	-	0.49
2040	0.53	-	-	-	0.53
2041	0.56	-	-	-	0.56
2042	0.60	-	-	-	0.60
2043	0.63	-	-	-	0.63
2044	0.67	-	-	-	0.67
2045	0.70	-	-	-	0.70
2046	0.74	-	-	-	0.74
2047	0.77	-	-	-	0.77

[a] EPA estimates that states will not incur MR&R costs for the Final NSPS for New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units.

[b] EPA estimates that industry will not incur MR&R costs for the Final EGs for Existing Fossil Fuel-Fired Electric Generating Units.

3.4 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. EPA used IPM to project likely future electricity market conditions with and without the final NSPS and Emission Guidelines.

IPM, developed by the consultancy 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. The model accounts for all major electric regions throughout the country, including transmission capabilities and constraints between them. This ensures that key transmission constraints are represented in IPM and that each individual IPM region has less internal transmission congestion based on today's loads and resource mix.

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. 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.[53]

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.[54]

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

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[53] 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/power-sector-modeling.

[54] See Chapter 8 of EPA's Baseline run using IPM v6 documentation, available at: https://www.epa.gov/power-sector-modeling

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.[55]

To estimate the annualized costs of additional capital investments in the power sector, 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.[56] 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.[57]

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, 2011a), the Mercury and Air Toxics Standards (U.S. EPA, 2011b), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015b), the Cross-State Air Pollution Update Rule (U.S. EPA, 2016), the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (U.S. EPA, 2019), and the Revised Cross-State Air Pollution Update Rule (U.S. EPA, 2021), and the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (U.S. EPA, 2023). EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including contributing to RIAs for the Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014a), the Disposal of Coal Combustion Residuals from Electric Utilities rule (U.S. EPA, 2015c), the Steam Electric Effluent Limitation Guidelines (U.S. EPA, 2015a), and the Steam Electric Reconsideration Rule (U.S. EPA, 2020)

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of

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[55] See Chapter 7 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling

[56] See Chapter 10 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling

[57] Costs modeled in IPM reflect the costs faced by industry, and therefore are net of subsidies included in the IRA

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 September 2019 U.S. EPA commissioned a peer review of EPA Baseline version 6, and in October 2014 U.S. EPA commissioned a peer review of EPA Baseline version 5.13 using the Integrated Planning Model.[58] Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies.[59] 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.

3.5 EPA's Power Sector Modeling of the Baseline Run and Three Illustrative Scenarios

The IPM "baseline" 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 represents an element of the baseline for this RIA.[60] EPA frequently updates the IPM baseline to reflect the latest 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. The IPM baseline also includes power-sector related provisions from the IRA.[61]

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[58] See Response and Peer Review Reports, available at: https://www.epa.gov/power-sector-modeling/ipm-peer-reviews.

[59] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act

[60] 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" (U.S. EPA, 2014b).

[61] A wide variety of modeling teams have assessed baselines with IRA. The baseline estimated here is generally in line with these other estimates. See Bistline, et al. (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022," In Preparation.

3.5.1 EPA's IPM Baseline Run v7.23

For our analysis of the final NSPS, and the final Emissions Guidelines, EPA used EPA’s Power Sector Platform 2023 using IPM, as well as a companion updated database of EGU units (the National Electricity Energy Data System or NEEDS 12-04-23) that is used in EPA’s modeling applications of IPM.[62] The IPM Baseline includes the CSAPR (2011a), CSAPR Update (2016), the Revised CSAPR Update (2021), and the proposed Good Neighbor Plan for 2015 Ozone NAAQS (2023), as well as the Mercury and Air Toxics Standards (2020). The baseline also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.[63] Finalized in December 2021, the impacts of the 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards are also captured in the baseline; the rule includes requirements for model years 2023 through 2026. The impacts of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review are not captured in the baseline.[64] The proposed GNP Supplemental Rule (2023), the proposed Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2023), the proposed Heavy-duty Greenhouse Gas “Phase 3” for Model Years 2027 and Later (2023), the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (2023), and the proposed Steam Electric Power Generating Effluent Guidelines (2023) were not included. Additionally, the model was also updated to account for recent updates to state and federal legislation affecting the power sector, including Public Law 117-169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 (IRA). The Integrated Planning Model (IPM) Documentation includes a summary of all legislation reflected in this version of the model as well as a description of how that legislation is implemented in the model. The IPM documentation provides details on the provisions of the IRA that were incorporated into this analysis, including provisions relating to tax subsidies for non-emitting

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[62] https://www.epa.gov/power-sector-modeling

[63] For a full list of modeled policy parameters, please see: https://www.epa.gov/airmarkets/power-sector-modeling

[64] 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

generation, energy storage, and CCS.[65] The model runs for the main RIA analysis examine the combined effects of the final NSPS, and the final Emissions Guidelines. Appendix C examines the impact of the two rules independently. The analysis of power sector cost and impacts presented in this section is based on a single IPM Baseline run, and represents incremental impacts projected solely as a result of compliance with the GHG mitigation measures presented in Table 3-1, Table 3-2, and Table 3-3.

3.5.2 Methodology for Evaluating the Illustrative Scenarios

To estimate the costs, benefits, and economic and energy market impacts of the final NSPS, and the final Emissions Guidelines, EPA conducted quantitative analysis of the three illustrative scenarios: one scenario representing the final rules, and two scenarios representing alternative sets of requirements. Details about these illustrative scenarios as analyzed in this RIA, are provided above in Section 3.2.

Before undertaking power sector analysis to evaluate compliance with the illustrative scenarios, EPA first considered available GHG mitigation strategies that could be implemented by the 2035 run year. EPA considered the following GHG control strategies: Carbon Capture and Storage (CCS), efficient generation practices, natural gas co-firing at existing coal-fired EGUs and hydrogen co-firing at new combined cycle and combustion turbine EGUs. EPA then developed subcategory definitions that assigned GHG mitigation measures to the appropriate affected sources.[66] This RIA projects the system-wide least-cost strategies for complying with the assigned GHG mitigation measures. Least-cost compliance may lead to the application of different control strategies at a given source, which is in keeping with the cost-saving compliance flexibility afforded by this rulemaking.

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[65] The Inflation Reduction Act (IRA) contains a number of tax credit provisions that affect power sector operations. The Clean Electricity Investment and Production Tax Credits (provisions 48E and 45Y of the IRA) are described in more detail in Section 4. The credit for Carbon Capture and Sequestration (provision 45Q) is described in Section 3. The impacts of the Zero-Emission Nuclear Power Production Credit (provision 45U) are reflected through modifying nuclear retirement limits, as described in Section 4. The Credit for the Production of Clean Hydrogen (provision 45V) is reflected through the inclusion of an exogenously delivered price of hydrogen fuel, see Section 9. The Advanced Manufacturing Production Tax Credit (45X) was reflected through adjustments to the short-term capital cost added for renewable technologies, see Section 4. For a discussion of the uncertainties around the modeling of the impacts of the IRA including CCS and market conditions, please see the Limitations Discussion in Section 3.7. Documentation is available at: https://www.epa.gov/power-sector-modeling

[66] For details, please see sections VII, VIII and X of the preamble.

While CCS at new and existing sources and co-firing natural gas at existing coal facilities[67] are captured endogenously within IPM v6.21, hydrogen co-firing at new gas EGUs is at present represented exogenously, but alternative representations are likely to be considered in future modeling.

Hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1.15/kg, inclusive of $3/kg subsidies under the IRA. These costs are consistent with DOE projections of 2030 for delivered costs of electrolytic low-GHG hydrogen in the range of $0.70/kg to $1.15/kg for power sector applications, given R&D advancements and economies of scale.[68] A growing number of studies are demonstrating more efficient and less expensive techniques to produce low-GHG electrolytic hydrogen; and, tax credits and market forces are expected to accelerate innovation and drive down costs even further over the next decade.[69] [70] [71]

We also note the model does not track upstream emissions associated with the production of the hydrogen (or any other modeled fuels such as coal and natural gas), nor any incremental electricity demand associated with its production. Under the illustrative Final Rules scenario, incremental electricity demand from hydrogen production in 2035 is estimated at about 0.1 GWh, or less than 0.001 percent of the total projected nationwide generation.

As noted in Section 5.2, IPM estimates compliance costs incurred by regulated firms, but because of the availability of subsidy payments, there are also real resource costs to the economy outside of the regulated sector. IPM provides EPA's best estimate of the costs of the final rules to the electricity sector and related energy sectors (i.e., natural gas, coal mining). To estimate the social costs for the economy as a whole, EPA has used information from IPM as an input into the

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[67] For details on CCS modeling in IPM, please see Chapter 6 of the documentation, available at: https://www.epa.gov/power-sector-modeling. Additionally, EPA has summarized the CCS costs for affected existing coal-fired steam generating units in the "GHG Mitigation Measures for Steam EGUs" Technical Support Document. For the universe of coal-fired steam generating units that have not committed to retirement or convert to gas by 2039, assuming a 12 year amortization period and an 80% capacity factor, EPA estimates the average abatement cost to be -$5/ton, inclusive of 45Q tax subsidies.

[68] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023 See: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf

[69] "Sound waves boost green hydrogen production," Power Engineering, January 4, 2023.

[70] "Direct seawater electrolysis by adjusting the local reaction environment of a catalyst," Nature Energy, January 30, 2023.

[71] Hydrogen from Next-generation Electrolyzers of Water (H2NEW) | H2NEW (energy.gov)

Agency's computable general equilibrium model, SAGE. The economy-wide analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM.

The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the finalized rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the finalized rules. We are not able to identify their relative roles at this time. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. See Section 5.2 for more discussion on the economy-wide analysis with SAGE and estimates of private and social costs.

3.5.3 Methodology for Estimating Compliance Costs

This section describes EPA's approach to quantify estimated compliance costs in the power sector associated with the three illustrative scenarios, which include estimates projected directly by the model, and costs estimated outside the model framework. The model projections capture the costs associated with installation of GHG mitigation measures at affected sources as well as the resulting effects on dispatch as the relative operating costs for units are affected. Additionally, EPA estimates monitoring, reporting and recordkeeping (MR&R) costs for affected EGUs for the timeframe of 2024 to 2047, and these costs are added to the estimated change in the total system production cost projected by IPM.

3.6 Estimated Impacts of the Illustrative Scenarios

3.6.1 Emissions Reduction Assessment

As indicated in Section 3.2, the EGU CO_2 emissions reductions are presented in this RIA from 2028 through 2045 and are based on IPM projections. Table 3-5 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios. The alternative scenarios produce smaller emissions reductions than the final rules.

Table 3-5 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Scenarios from 2028 through 2045 [72]

Annual CO_2		Total Emissions			Change from Baseline		
(million metric tons)	Baseline	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2
2028	1,159	1,121	1,123	1,127	-38	-36	-32
2030	1,098	1,048	1,050	1,071	-50	-48	-27
2035	724	601	601	603	-123	-124	-122
2040	459	406	406	406	-54	-53	-53
2045	307	265	267	267	-42	-40	-40

Within the compliance modeling, sources within each subcategory are subject to GHG mitigation measures beginning in 2030. Since IPM is forward looking, investment decisions prior to the start of the program are influenced by how those assets would fare under the policy assumed. Hence, we see small reductions in 2028, prior to the imposition of the policy in 2030. Emission reductions peak in 2035 across all scenarios, reflective of the start of the requirements on existing coal-fired EGUs. Under the alternative 1 and alternative 2 scenarios, the baseload definition is assumed to be 50 percent under the NSPS, while the final rules scenario assumes a 40 percent baseload definition. The final rules and alternative 1 scenarios assume all medium-term existing coal-fired steam generating units must co-fire at least 40 percent natural gas by 2030, while the alternative 2 scenario assumes that all medium-term existing coal fired steam generating units must co-fire at least 40 percent natural gas by 2035.

The impact of the IRA is to increase the cost-competitiveness of low-emitting technology, with the result that emissions are projected to fall significantly over the forecast period under the baseline. Hence reductions from the rules are highest in 2035 relative to the baseline and also decline over time. For details on the EGU emissions controls assumed in each of the illustrative scenarios, please see Table 3-1, Table 3-2, and Table 3-3.

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

In addition to the annual CO_2 reductions, there will also be reductions of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce annual CO_2 emissions. These other emissions include the annual total changes in emissions of NO_X, SO_2, direct $PM_{2.5}$, and ozone season NO_X emissions changes. The emissions reductions are presented in Table 3-6.

Table 3-6 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, $PM_{2.5}$, Hg and Ozone NO_X for the Illustrative Scenarios for 2028 to 2045

Annual NO_X	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	461	441	442	444	-20	-19	-17
2030	393	374	374	382	-20	-20	-11
2035	259	210	207	211	-49	-51	-48
2040	173	166	166	167	-6	-7	-5
2045	107	83	83	83	-24	-24	-24
Ozone Season NO_X[a]	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	189	183	183	184	-6	-6	-5
2030	175	168	168	171	-7	-7	-4
2035	119	100	99	101	-19	-20	-18
2040	88	82	82	82	-6	-6	-6
2045	59	45	45	45	-14	-14	-14
Annual SO_2	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	454	420	424	426	-34	-30	-28
2030	334	313	317	319	-20	-16	-15
2035	240	150	150	146	-90	-90	-94
2040	143	139	139	135	-4	-4	-8
2045	55	13	13	14	-41	-41	-41
Annual Mercury	**Total Emissions**				**Change from Baseline**		
(Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	3.1	3.0	3.0	3.0	-0.1	-0.1	-0.1
2030	2.9	2.8	2.8	2.9	-0.1	-0.1	0.0
2035	2.5	2.4	2.4	2.4	-0.1	-0.1	-0.1
2040	2.0	2.3	2.3	2.3	0.2	0.2	0.3
2045	1.4	1.2	1.2	1.2	-0.2	-0.2	-0.1
Direct $PM_{2.5}$	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Final Rule**	**Alt 1**	**Alt 2**	**Final Rule**	**Alt 1**	**Alt 2**
2028	71	69	69	69	-2	-2	-1
2030	66	65	65	65	-2	-2	-1
2035	51	49	49	49	-1	-2	-1
2040	37	39	39	39	2	1	2
2045	24	22	22	22	-2	-2	-2

[a] Ozone season is the May through September period in this analysis.

3.6.2 Compliance Cost Assessment

The estimates of the changes in the cost of supplying electricity for the illustrative scenarios presented in Table 3-7.[73] Since the rules are estimated to result in additional recordkeeping, monitoring or reporting requirements, the costs associated with compliance, monitoring, recordkeeping, and reporting requirements are included within the estimates in this table.

Table 3-7 National Power Sector Compliance Cost Estimates (billions of 2019 dollars) for the Illustrative Scenarios

	Final Rules	Alternative 1	Alternative 2
2024 to 2042 (Annualized)	0.43	0.46	0.38
2024 to 2047 (Annualized)	0.86	0.88	0.85
2028 (Annual)	-1.30	-1.08	-1.06
2030 (Annual)	-0.22	-0.05	-0.72
2035 (Annual)	1.28	1.21	1.16
2040 (Annual)	0.59	0.64	0.60
2045 (Annual)	3.34	3.26	3.59

"2024 to 2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2042 and discounted using a 3.76 real discount rate.[74] This does not include compliance costs beyond 2042. "2024 to 2047 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2047 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2047. "2028 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those run years.[75]

There are several notable aspects of the results presented in Table 3-7. One notable result in Table 3-7 is that the estimated annual compliance costs for the three scenarios are negative (i.e., a cost reduction) in 2028 and 2030, although these illustrative scenarios reduce CO_2 emissions as shown in Table 3-5. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given the assumption of perfect foresight. IPM's

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[73] 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.

[74] This table reports compliance costs consistent with expected electricity sector economic conditions. The PV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. 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). The PV of costs was then used to calculate the levelized annual value over a 19-year period (2024 to 2042) and a 24-year period (2024 to 2047) using the 3.76 percent rate as well. Table 3-7 reports the PV of the annual stream of costs from 2024 to 2047 using 3 percent and 7 percent consistent with OMB guidance.

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

objective function is to minimize the discounted present value (PV) of a stream of annual total cost of generation over a multi-decadal time period.[76] Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2030 run year on some coal-fired EGUs that currently lack them. Under the scenarios modeled, a subset of these facilities retires rather than retrofit, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Additionally, renewable costs are assumed to decline over the forecast period. Given IPM's perfect foresight, the model choses to wait to build incremental RE until later in the period when costs are lower. Under the illustrative policy scenarios the model builds this capacity sooner, which results in lower costs in the years built, but higher costs in future years.

Costs peak in 2035 across all scenarios, reflecting the date of imposition of the final Emission Guidelines for coal-fired steam generating units and tightening NSPS requirements. The final rules scenario results in the greatest early buildout of RE, resulting in the lowest near-term costs and higher longer-term costs. As a result, over the 2024 - 2047 time period, the final rules scenario shows slightly lower costs than alternative 1 and alternative 2. However, over the entire forecast period, costs are higher under the final rules.[77]

In addition to evaluating annual compliance cost impacts, EPA believes that a full understanding of these three illustrative scenarios benefits from an evaluation of annualized costs over the 2028 to 2045 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 illustrative scenario.[78] For this analysis we first calculated the PV of the stream of costs from 2024 through 2045[79] 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 PV of the stream of total costs of electricity generation. This discount rate is meant to capture the observed equilibrium market rate at which

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[76] For more information, please see Chapter 2 of the IPM documentation.

[77] The present value of costs over the 2024-57 time period using a 3.76 percent discount rate are $18.6 billion for the alternative 1, $18.8 billion for the final rules, and $18.1 billion for the alternative 2.

[78] The XNPV() function in Microsoft Excel for Windows 365 was used to calculate the PV of the variable stream of costs, and the PMT() function in Microsoft Excel for Windows 365 is used to calculate the level annualized cost from the estimated PV.

[79] Consistent with the relationship between IPM run years and calendar years, EPA assigned run year compliance cost estimates to all calendar years mapped to that run year. For more information, see Chapter 7 of the IPM Documentation.

investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).[80] After calculating the PV of the cost streams, the same 3.76 percent discount rate and 2024 to 2047 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 3-7.[81] The same approach was used to develop the annualized cost estimates for the 2024 to 2047 timeframe.

3.6.3 Impacts on Fuel Use, Prices, and Generation Mix

The final NSPS, and the final Emissions Guidelines are expected to result in significant GHG emissions reductions. The rules are also expected to have some impacts to the economics of the power sector. Consideration of these potential impacts is an important component of assessing the relative impact of the illustrative scenarios. 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 2028, 2030, 2035, 2040, and 2045 IPM model run years.

Table 3-8 and Table 3-9 present the percentage changes in national coal and natural gas usage by EGUs in the 2028, 2030, 2035, 2040 and 2045 run years. These fuel use estimates reflect some power companies choosing natural gas and renewables over coal in 2030 rather than implement available cost-reasonable controls as a result of the imposition of GHG mitigation measures under the final Emissions Guidelines for coal-fired steam generating units.

Under the baseline, current market trends persist and are accentuated by the IRA. Hence coal capacity continues to decline over the forecast period, and there is continued penetration of non-emitting resources such as wind and solar.

Of the 181 GW of coal-fired capacity active in 2023, only 80 GW have not announced retirement or coal to gas conversion by 2040. Furthermore, of these 80 GW, by 2040 56 GW will be 53 years or older (which is the average retirement age for coal EGUs over the 2015-22 time

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[80] The IPM Baseline run documentation (Appendix B.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 percent."

[81] The PMT() function in Microsoft Excel for Windows 365 is used to calculate the level annualized cost from the estimated PV.

period).[82] EPA projects that under the baseline, 42 GW of coal are projected to be active in 2040. Coal consumption declines consistent with this decrease in capacity over the forecast period.

At the same time, tighter natural gas markets as a result of increased LNG exports results in declining gas consumption over the forecast period, particularly after 2035, when improved renewable cost and performance consistent with NREL ATB 2023 further erode gas generation share. In the baseline, increases in LNG exports reach their highest levels by 2040, resulting in tighter natural gas markets. At the same time, RE cost and performance improvements mean that RE becomes more competitive. This results in less gas and more RE deployment, driving down emissions. In other words, emissions decline over the forecast period in the baseline, and decline faster in 2040 and 2045. Steam retirements continue over the forecast period. As a result in the policy scenario, requirements on existing steam generation result in large reductions in 2035 driven by lower thermal generation and increased adoption of BSER technology but then emissions begin to converge back to baseline levels.

Under the illustrative scenarios, increases in gas demand are highest in 2035, driven by reductions in coal-fired generation as a result of the existing source standards. After 2035, the absolute increases in gas consumption are smaller, consistent with baseline trends towards declining gas consumption and higher levels of RE deployment. In 2030, increases in gas consumption are lowest under the alternative 2 scenario, consistent with shifting the requirements on medium-term coal fired electricity generating steam units assumed from 2030 under the final rules and alternative 1 to 2035 in the alternative 2 scenario.

To put these reductions into context, under the Baseline, power sector coal consumption is projected to decrease from 251 million tons in 2028 to 222 million tons in 2030 (5 percent annually between 2028-2030), and to 147 million tons in 2035 (7 percent annually between 2030-2035). Under the final rules, coal consumption is projected to decrease from 234 million tons in 2028 to 194 million tons in 2030 (8 percent annually between 2028-2030), and 111 million tons in 2035 (9 percent annually between 2030-2035). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.[83] Coal

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[82] The annual average retirement age for coal-fired EGUs between 2000-2022 ranged between 47 and 61 years old, and the average retirement age over that period was 53 years. Similarly, the average age for retiring coal-fired EGUs between 2015-2022 was 53 years, demonstrating the consistency of retirement ages throughout the years.

[83] U.S. EIA Monthly Energy Review, Table 6.2, January 2022.

consumption falls by the greatest amount in 2035, consistent with the imposition of the requirements on existing coal-fired steam generating units. For units that adopt CCS, 45Q tax credits result in higher levels of dispatch and therefore coal consumption at those sources relative to the baseline. These sources consume different types of coal depending on location and relative cost, resulting in non-uniform subnational coal consumption impacts (i.e. production declines in some regions and increases in others).

Table 3-10 presents the projected hydrogen power sector consumption under the Baseline and the Illustrative Scenarios.[84]

Table 3-8 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use for the Baseline and the Illustrative Scenarios

		Million Tons				Percent Change from Baseline		
	Year	**Baseline**	**Final**	**Alt. 1**	**Alt. 2**	**Final**	**Alt. 1**	**Alt. 2**
Appalachia	2028	40	37	36	37	-7%	-8%	-7%
Interior		38	35	36	36	-7%	-5%	-4%
Waste Coal		7	7	7	7	0%	0%	0%
West		166	155	156	156	-7%	-6%	-6%
Total		251	234	235	237	-7%	-6%	-6%
Appalachia	2030	39	39	39	39	0%	1%	0%
Interior		35	36	36	34	1%	2%	-2%
Waste Coal		7	7	7	7	0%	0%	0%
West		141	113	113	133	-20%	-20%	-6%
Total		222	194	195	214	-13%	-12%	-4%
Appalachia	2035	32	19	19	19	-40%	-40%	-40%
Interior		19	25	25	25	30%	30%	30%
Waste Coal		7	3	3	3	-53%	-53%	-53%
West		89	63	63	67	-29%	-29%	-25%
Total		147	111	111	114	-25%	-25%	-22%
Appalachia	2040	19	19	19	19	1%	1%	0%
Interior		10	25	25	25	150%	150%	150%
Waste Coal		3	3	3	3	0%	0%	0%
West		61	56	56	59	-8%	-8%	-3%
Total		93	103	103	106	11%	11%	14%
Appalachia	2045	4	0	0	0	-100%	-100%	-100%
Interior		1	0	0	0	-100%	-100%	-85%
Waste Coal		3	0	0	0	-100%	-100%	-100%
West		20	3	3	3	-85%	-85%	-84%
Total		28	3	3	3	-89%	-90%	-88%

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[84] Please note that hydrogen consumption is rounded to the nearest trillion Btu.

Table 3-9 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use for the Baseline and the Illustrative Scenarios

	Trillion Cubic Feet				Percent Change from Baseline		
Year	Baseline	Final	Alt. 1	Alt. 2	Final	Alt. 1	Alt. 2
2028	11.6	11.5	11.5	11.5	-1.0%	-1.0%	-1.0%
2030	11.7	11.7	11.7	11.5	0.0%	0.0%	-1.7%
2035	9.3	9.7	9.7	9.7	4.3%	4.4%	4.4%
2040	6.4	6.4	6.4	6.4	-0.1%	0.0%	0.0%
2045	4.2	4.3	4.3	4.3	1.1%	1.9%	1.8%

Table 3-10 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Hydrogen Use for the Baseline and the Illustrative Scenarios

	Trillion Btu			
Year	Baseline	Final	Alt. 1	Alt. 2
2028	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00
2045	0.22	0.45	0.49	0.44

Table 3-11 and Table 3-12 present the projected coal and natural gas prices in 2028, 2030, 2035, 2040 and 2045, as well as the percent change from the baseline projected due to the illustrative scenarios. In 2028, earlier RE builds result in lower gas consumption and higher gas prices. By 2030, reductions in coal generation stemming from requirements on medium-term coal fired electricity generating steam units result in higher gas consumption and prices. In 2035, increases in gas consumption are highest relative to the baseline, stemming from the requirements on long-term coal fired electricity generating steam units and the NSPS. Impacts lessen in 2040 onwards as the system approaches baseline levels with higher levels of RE generation, and less gas and coal generation.

Under the alternative 2, gas prices remain similar to baseline levels in 2030 as a result of the requirements on medium-term coal fired electricity generating steam units assumed to take place in 2035. Under the final rules scenario, the lower baseload threshold results in lower amounts of generation from new gas, resulting in smaller increases in gas generation relative to baseline levels than under the alternative 1 and alternative 2 illustrative scenarios.

Growing LNG exports result in tighter natural gas markets, particularly in 2035 and beyond, while RE cost and performance continues to improve. At the same time, requirements on new combustion turbines result in fewer new NGCCs that run at baseload levels. This means that as steam generation falls, it is filled by a combination of higher existing gas and new RE generation, tamping down on the increase in gas consumption.

Table 3-11 2028, 2030, 2035, 2040 and 2045 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				**Percent Change from Baseline**		
		Baseline	**Final**	**Alt. 1**	**Alt. 2**	**Final**	**Alt. 1**	**Alt. 2**
Minemouth	2028	0.98	0.97	0.97	0.97	-1%	-1%	-1%
Delivered		1.54	1.52	1.52	1.52	-1%	-1%	-1%
Minemouth	2030	1.02	1.05	1.05	1.02	3%	3%	0%
Delivered		1.56	1.53	1.53	1.54	-2%	-2%	-1%
Minemouth	2035	1.07	1.10	1.10	1.09	3%	3%	2%
Delivered		1.55	1.55	1.55	1.54	0%	0%	0%
Minemouth	2040	1.17	1.22	1.22	1.21	4%	4%	3%
Delivered		1.59	1.60	1.60	1.60	1%	1%	0%
Minemouth	2045	1.37	1.50	1.50	1.50	9%	9%	9%
Delivered		1.38	0.94	0.94	0.94	-32%	-32%	-32%

Table 3-12 2028, 2030, 2035, 2040 and 2045 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2019 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				Percent Change from Baseline		
		Baseline	Final	Alt. 1	Alt. 2	Final	Alt. 1	Alt. 2
Henry Hub	2028	2.78	2.72	2.74	2.74	-2%	-2%	-2%
Delivered		2.84	2.78	2.80	2.80	-2%	-2%	-2%
Henry Hub	2030	2.89	2.90	2.91	2.87	0%	1%	-1%
Delivered		2.95	2.97	2.98	2.93	1%	1%	0%
Henry Hub	2035	2.87	2.95	2.95	2.95	3%	3%	3%
Delivered		2.88	2.97	2.97	2.97	3%	3%	3%
Henry Hub	2040	2.82	2.79	2.81	2.81	-1%	0%	0%
Delivered		2.79	2.77	2.79	2.79	-1%	0%	0%
Henry Hub	2045	2.95	2.95	2.95	2.95	0%	0%	0%
Delivered		2.94	2.94	2.94	2.94	0%	0%	0%

Gas capacity is higher as a result of greater NGCT buildout. These NGCT units operate at low capacity factors, which means gas consumption is similar between the two scenarios, as is natural gas price.

Table 3-13 presents the projected percentage changes in the amount of electricity generation in 2028, 2030, 2035 and 2040 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA projects an overall shift from coal to gas and renewables under the baseline, and these trends persist under the illustrative scenarios analyzed. The projected impacts are highest in 2035 reflecting the imposition of the final Emissions Guidelines and are smaller thereafter. 45(q) is available for 12 years within the modeling,[85] after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

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[85] EPA assumes a 12-year booklife for CCS consistent with the duration of the 45(q) tax credit

Table 3-13 2028, 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type for the Baseline and the Illustrative Scenarios

		Generation (TWh)				Percent Change from Baseline		
	Year	Baseline	Baseline	Final	Alt. 1	Final	Alt. 1	Alt. 2
Unabated Coal	2028	472	441	443	447	-7%	-6%	-5%
Coal & CCS		0	0	0	0	-	-	-
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		1,652	1,631	1,634	1,633	-1%	-1%	-1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		751	751	751	751	0%	0%	0%
Hydro		293	293	293	293	0%	0%	0%
Non-Hydro RE		1,141	1,191	1,186	1,182	4%	4%	4%
Oil/Gas Steam		26	28	27	27	8%	7%	7%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,365	4,366	4,365	4,365	0%	0%	0%
Unabated Coal	2030	407	355	357	391	-13%	-12%	-4%
Coal & CCS		3	5	5	3	71%	76%	0%
Coal with Nat. Gas co-firing		0	2	2	0	-	-	-
Unabated Nat. Gas		1,670	1,660	1,664	1,642	0%	0%	-1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		729	729	729	729	0%	0%	0%
Hydro		298	299	298	298	0%	0%	0%
Non-Hydro RE		1,329	1,381	1,377	1,373	4%	4%	3%
Oil/Gas Steam		25	28	27	25	12%	11%	3%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,491	4,491	4,491	4,491	0%	0%	0%
Unabated Coal	2035	160	0	0	0	-100%	-100%	-100%
Coal & CCS		76	133	133	136	74%	74%	78%
Nat. Gas co-firing		0	4	4	6	-	-	-
Unabated Nat. Gas		1,341	1,379	1,386	1,384	4%	4%	4%
Nat. Gas & CCS		3	7	6	6	105%	64%	64%
Nuclear		667	666	666	666	0%	0%	0%
Hydro		319	317	317	317	-1%	-1%	-1%
Non-Hydro RE		2,229	2,286	2,281	2,278	3%	2%	2%
Oil/Gas Steam		8	9	9	9	21%	16%	17%
Other		31	30	30	30	0%	0%	0%
Grand Total		4,834	4,831	4,833	4,832	0%	0%	0%
Unabated Coal	2040	61	0	0	0	-100%	-100%	-100%
Coal & CCS		76	128	128	131	68%	68%	73%

Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		933	919	924	924	0%	0%	0%
Nat. Gas & CCS		3	7	6	6	105%	64%	64%
Nuclear		614	613	613	613	0%	0%	0%
Hydro		336	336	336	336	0%	0%	0%
Non-Hydro RE		3,097	3,119	3,114	3,111	1%	1%	0%
Oil/Gas Steam		5	6	6	6	28%	27%	27%
Other		29	29	29	29	0%	0%	0%
Grand Total		5,154	5,157	5,156	5,155	0%	0%	0%
Unabated Coal	2045	45	0	0	0	-100%	-100%	-100%
Coal & CCS		4	3	3	4	-7%	-9%	4%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		614	612	620	619	1%	2%	2%
Nat. Gas & CCS		3	6	5	5	103%	65%	65%
Nuclear		471	472	473	473	0%	0%	0%
Hydro		343	342	342	342	0%	0%	0%
Non-Hydro RE		4,032	4,089	4,081	4,081	1%	1%	1%
Oil/Gas Steam		4	6	6	6	25%	25%	25%
Other		28	27	27	27	0%	0%	0%
Grand Total		5,544	5,557	5,557	5,556	0%	0%	0%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind. Oil/Gas steam category includes coal to gas conversions.

Table 3-14 presents the projected percentage changes in the amount of generating capacity in 2028, 2030, 2035, 2040 and 2045 by primary fuel type. In 2035, the final Emission Guidelines is assumed to be in effect under all three scenarios. Under the final rules, 104 GW of coal-fired EGUs have committed retirements by 2035 (21 GW incremental to baseline). One GW of coal-fired EGUs who have committed to retirement by 2040 are medium-term existing coal-fired steam generating units and, as such, install 40 percent natural gas co-firing requirement. 19 GW of coal-fired EGUs who plan to operate past 2040 are subject to the long-term existing coal-fired steam generating unit subcategory and, as such, install CCS (reflecting 8 GW incremental to the baseline). Finally, 19 GW of coal-fired EGUs undertake coal to gas conversion (6 GW incremental to the baseline).

Under the baseline, total coal retirements between 2028 and 2035 are projected to be 84 GW (or 12 GW annually). Under the final rules, total coal retirements between 2028 and 2035 are projected to be 104 GW (or 15 GW annually). This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020.[86]

By 2030 the final rules are projected to result in an additional 5 GW of coal retirements, by 2035 an incremental 21 GW of coal retirements and by 2040 an incremental 14 GW of coal retirements relative to the baseline. These compliance decisions reflect EGU operators making least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to maintain resource adequacy.[87]

IPM endogenously estimates the capacity credit (i.e. the accredited capacity that can count towards meeting the resource adequacy constraints within the model) for wind, solar, and storage as a function of penetration.[88] Additionally, IPM models operating reserves at the regional level, and can account for the impact of solar and wind on operating reserves requirements.[89]

An incremental 15 GW of renewable capacity additions (consisting of an incremental 3 GW of solar and 12 GW of wind builds) and 9 GW of storage is projected by 2035 in the illustrative final rule. Under the final rules, 18 GW of economic NGCC additions occur by 2035 (1 GW less than the baseline), and 24 GW of economic NGCT additions occur by 2035 (10 GW incremental to the baseline). These builds partially reflect early action, i.e., builds that would otherwise have occurred later in the forecast period under the baseline. Of these units, 870 MW of NGCCs install CCS in 2035.

Under the baseline, the reduction in generation from natural-gas and coal fired facilities is greater than the reduction in their capacities over time. Hence thermal resources tend to be operated less frequently over time, due to the increase in low-emitting generation. These trends persist under the illustrative scenarios.

As shown in Figure 3.2 below, The coal-fired generation share was 49 percent in 2007 and 20 percent in 2022, and is projected to fall to 3 percent in 2040 under the baseline and 1 percent

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[86] See EIA’s Today in Energy: https://www.eia.gov/todayinenergy/detail.php?id=50838.

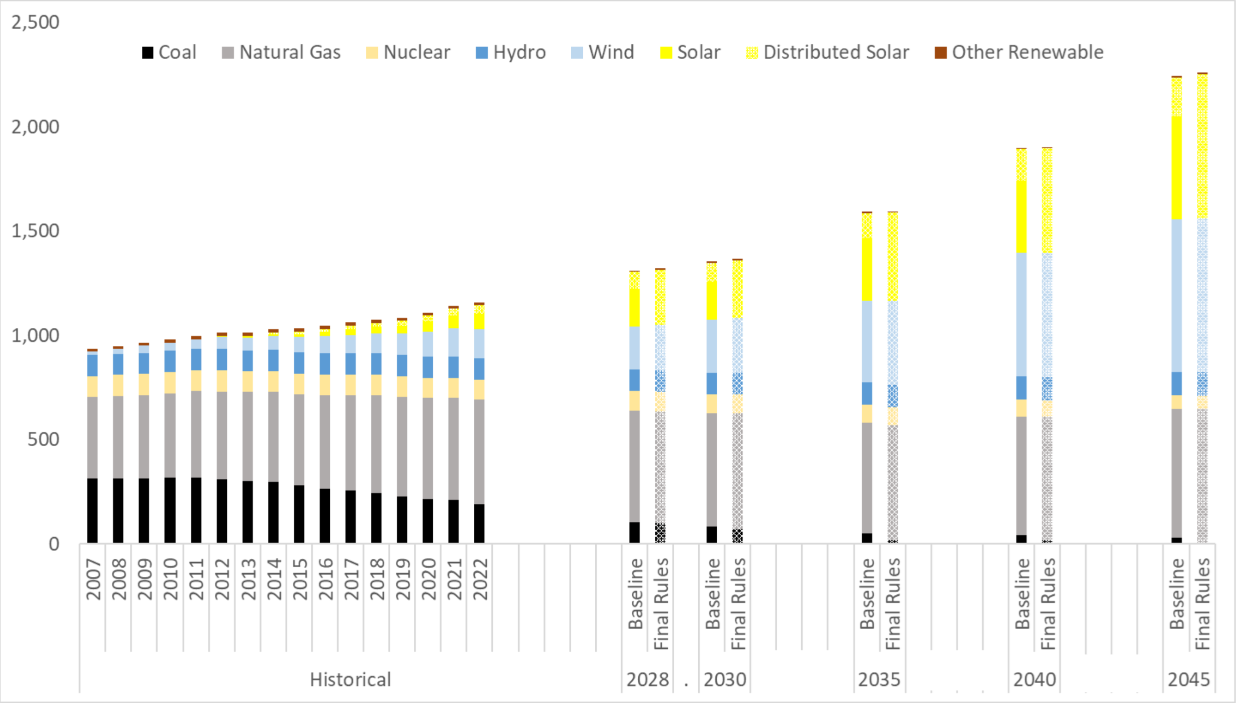
[87] For further discussion of how the rule is anticipated to integrate into the ongoing power sector transition while not impacting resource adequacy, see section XIV(F) of the preamble, and the Resource Adequacy Assessment TSD included in the docket.

[88] For details, please see chapter 4 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling

[89] For details, please see chapter 3 of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling

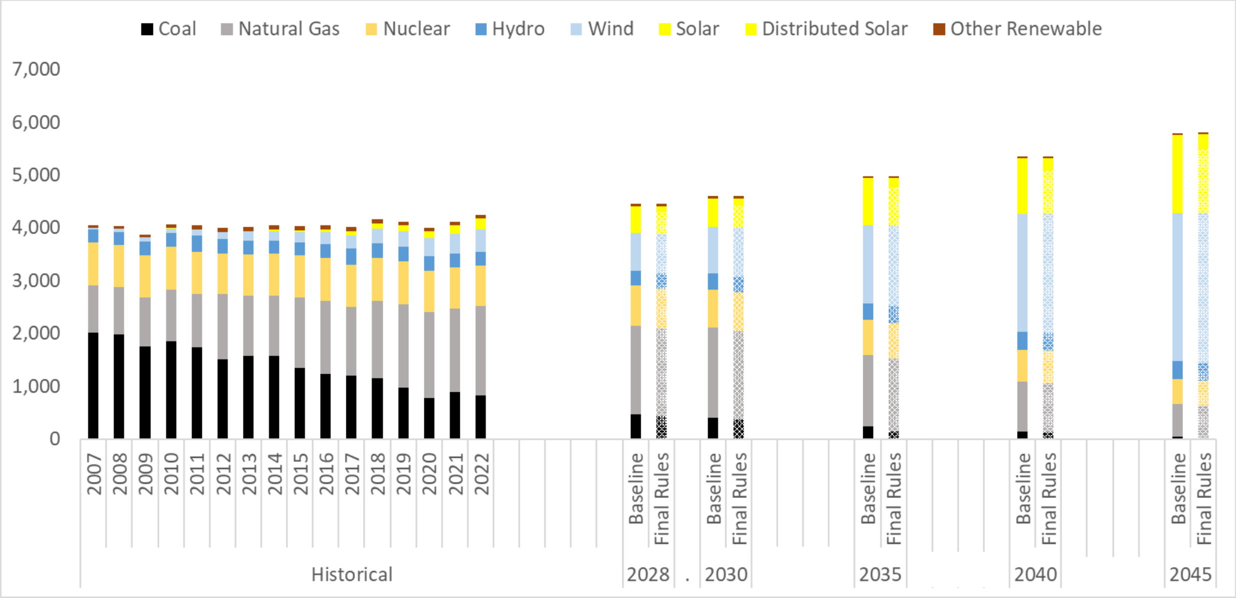
by 2045. Under the final rules scenario, coal-fired generation share is projected to fall to 2 percent by 2040 and less than 1 percent in 2045. The natural gas-fired generation share was 22 percent in 2007 and 39 percent in 2022 and is projected to fall to 18 percent in 2040 under the baseline and 11 percent by 2045. Under the final rules scenario, natural gas-fired generation share is projected to fall to 17 percent by 2040 and 11 percent in 2045. The wind and solar generation share was 1 percent in 2007 and 13 percent in 2022 and is projected to grow to 57 percent in 2040 under the baseline and 69 percent by 2045. Under the final rules scenario, wind and solar generation share is projected to grow to 58 percent by 2040 and 69 percent in 2045.

Figure 3-1 Historical and Projected Capacity Mix (GW)



Sources: EIA Power Annual and EPA projections

Figure 3-2 Historical and Projected Generation Mix (GW)



Sources: EIA Power Annual and EPA projections

Table 3-14 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type for the Baseline and the Illustrative Scenarios

		Capacity (GW)				Percent Change from Baseline		
	Year	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
Unabated Coal	2028	106	101	101	102	-4%	-4%	-4%
Coal & CCS		0	0	0	0	-	-	-
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		471	472	473	472	0%	0%	0%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		94	94	94	94	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		394	407	406	405	3%	3%	3%
Oil/Gas Steam		63	64	64	64	2%	2%	2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,236	1,246	1,246	1,245	1%	1%	1%
Unabated Coal	2030	85	72	72	80	-15%	-15%	-5%
Coal & CCS		0	1	1	0	72%	77%	0%
Coal with Nat. Gas co-firing		0	1	1	0	-	-	-
Unabated Nat. Gas		479	480	481	480	1%	1%	1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		91	91	91	91	0%	0%	0%
Hydro		104	104	104	104	0%	0%	0%
Non-Hydro RE		440	454	453	452	3%	3%	3%
Oil/Gas Steam		64	73	73	66	13%	13%	3%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,269	1,281	1,281	1,280	1%	1%	1%
Unabated Coal	2035	41	0	0	0	-100%	-100%	-100%
Coal & CCS		11	19	19	20	74%	74%	78%
Coal with Nat. Gas co-firing		0	1	1	1	-	-	-
Unabated Nat. Gas		476	484	484	484	2%	2%	2%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		84	84	84	84	0%	0%	0%
Hydro		107	107	107	107	0%	0%	0%
Non-Hydro RE		699	714	713	711	2%	2%	2%
Oil/Gas Steam		55	66	66	66	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,479	1,482	1,481	1,481	0%	0%	0%

Unabated Coal	2040	31	0	0	0	-99%	-99%	-99%
Coal & CCS		11	18	18	19	68%	68%	73%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		516	525	525	525	2%	2%	2%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		79	79	79	79	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		943	952	951	950	1%	1%	1%
Oil/Gas Steam		54	65	65	65	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,753	1,759	1,757	1,757	0%	0%	0%
Unabated Coal	2045	29	0	0	0	-99%	-99%	-99%
Coal & CCS		1	1	1	1	-5%	-7%	13%
Coal with Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		565	581	581	580	3%	3%	3%
Nat. Gas & CCS		0	1	1	1	104%	63%	63%
Nuclear		65	65	65	65	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		1,232	1,250	1,248	1,248	1%	1%	1%
Oil/Gas Steam		54	64	64	65	19%	19%	20%
Other		7	7	7	7	0%	0%	0%
Grand Total		2,065	2,080	2,078	2,078	1%	1%	1%

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

EPA estimated the change in the retail price of electricity (2019 dollars) using the Retail Price Model (RPM).[90] The RPM was developed by ICF for 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 region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with

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

EIA electricity market data for each of the 25 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).[91]

Table 3-15, Table 3-16, Table 3-17, and Table 3-18 present the projected percentage changes in the retail price of electricity for the three illustrative scenarios in 2030, 2035, 2040 and 2045, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to experience the largest impacts in 2035. Consistent with the decline in total production cost in 2030[92] National electricity rates are projected to fall 0.5 percent below baseline levels in 2030, or a decrease of 0.47 mills/kWh (2019 dollars). In 2035, EPA estimates that these rules will result in a 1 percent increase in national average retail electricity price, or by about 1.33 mills/kWh (2019 dollars). In 2040, EPA estimates that these rules will result in a 0.2 percent increase in national average retail electricity price, or by about 0.15 mills/kWh. In 2045, EPA estimates that these rules will result in a 0.7 percent increase in national average retail electricity price, or by about 0.63 mills/kWh.

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[91] See documentation available at: https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf

[92] Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2030 run year on some coal-fired EGUs that currently lack them. Under the scenarios modeled, a subset of these facilities retires rather than retrofit, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Additionally, renewable costs are assumed to decline over the forecast period. Given IPM's perfect foresight, the model choses to wait to build incremental RE until later in the period when costs are lower. Under the illustrative policy scenarios the model builds this capacity sooner, which results in lower costs in the years built, but higher costs in future years.

Table 3-15 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2030

All Sector	2030 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	73	73	73	73	-1%	-1%	-1%
FRCC	98	98	98	97	0%	0%	0%
MISW	93	93	93	93	0%	0%	-1%
MISC	91	91	91	91	0%	0%	-1%
MISE	109	107	107	107	-2%	-2%	-2%
MISS	86	83	83	83	-3%	-3%	-3%
ISNE	157	157	156	156	0%	0%	0%
NYCW	210	211	211	211	0%	0%	0%
NYUP	126	126	126	126	0%	0%	0%
PJME	110	107	107	106	-3%	-3%	-3%
PJMW	97	97	96	96	0%	-1%	-1%
PJMC	89	87	87	87	-3%	-3%	-3%
PJMD	76	77	76	76	0%	-1%	-1%
SRCA	92	92	92	92	0%	0%	0%
SRSE	95	95	95	95	0%	0%	0%
SRCE	71	71	71	71	0%	0%	0%
SPPS	78	78	78	77	0%	1%	-1%
SPPC	97	97	96	97	-1%	-1%	-1%
SPPN	65	66	66	65	1%	1%	0%
SRSG	102	102	102	102	0%	0%	0%
CANO	143	142	142	142	0%	-1%	-1%
CASO	174	173	173	173	0%	0%	-1%
NWPP	82	81	81	81	-1%	-1%	-1%
RMRG	101	100	100	100	0%	-1%	-1%
BASN	96	97	97	97	1%	1%	1%
NATIONAL	100	99	99	99	-0.5%	-1%	-1%

Table 3-16 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2035

All Sector	2035 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	78	80	80	80	2%	2%	2%
FRCC	92	92	92	92	1%	1%	1%
MISW	84	85	85	85	1%	1%	1%
MISC	81	82	82	82	1%	1%	1%
MISE	96	99	98	98	3%	3%	3%
MISS	79	81	81	81	2%	2%	2%
ISNE	156	156	156	156	0%	0%	0%
NYCW	209	210	210	210	0%	0%	0%
NYUP	125	126	125	125	1%	1%	1%
PJME	108	113	112	112	4%	3%	3%
PJMW	92	95	94	94	3%	3%	3%
PJMC	75	79	79	79	6%	5%	5%
PJMD	71	74	74	74	4%	3%	3%
SRCA	89	90	90	90	0%	0%	0%
SRSE	90	91	91	91	1%	1%	1%
SRCE	67	67	67	67	0%	0%	0%
SPPS	69	70	70	70	1%	1%	1%
SPPC	80	80	80	80	-1%	-1%	0%
SPPN	63	64	64	64	1%	1%	1%
SRSG	103	104	104	104	0%	0%	0%
CANO	140	141	141	141	1%	1%	1%
CASO	173	173	173	173	0%	0%	0%
NWPP	79	79	79	79	0%	0%	0%
RMRG	93	95	95	95	2%	2%	2%
BASN	97	96	96	96	-1%	-1%	-1%
NATIONAL	96	97	97	97	1%	1%	1%

Table 3-17 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2040

All Sector	2040 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	**Baseline**	**Final Rules**	**Alt. 1**	**Alt. 2**	**Final Rules**	**Alt. 1**	**Alt. 2**
TRE	74	73	73	73	0%	0%	0%
FRCC	88	89	89	89	0%	0%	0%
MISW	79	80	80	80	1%	1%	1%
MISC	73	73	73	73	0%	0%	0%
MISE	98	98	98	98	0%	0%	0%
MISS	74	75	75	74	1%	1%	0%
ISNE	167	168	168	168	1%	1%	1%
NYCW	236	235	235	235	0%	0%	0%
NYUP	138	138	138	138	0%	0%	0%
PJME	117	117	117	117	0%	0%	0%
PJMW	89	90	89	90	0%	0%	0%
PJMC	78	78	78	78	0%	0%	0%
PJMD	74	74	74	74	0%	0%	0%
SRCA	87	87	87	87	0%	0%	0%
SRSE	84	84	84	84	0%	0%	0%
SRCE	66	66	66	66	0%	0%	0%
SPPS	66	66	66	66	1%	1%	1%
SPPC	76	76	76	76	0%	0%	0%
SPPN	62	62	62	62	0%	0%	0%
SRSG	98	98	98	98	0%	0%	0%
CANO	144	145	145	145	0%	0%	0%
CASO	172	173	173	173	0%	0%	0%
NWPP	81	80	80	80	-1%	-1%	-1%
RMRG	88	88	88	88	1%	1%	0%
BASN	96	95	95	95	-1%	-1%	-1%
NATIONAL	95	95	95	95	0.2%	0.2%	0.1%

Table 3-18 Average Retail Electricity Price by Region for the Baseline and the Illustrative Scenarios, 2045

All Sector	2045 Average Retail Electricity Price (2019 mills/kWh)				Percent Change from Baseline		
Region	Baseline	Final Rules	Alt. 1	Alt. 2	Final Rules	Alt. 1	Alt. 2
TRE	66	66	66	66	1%	1%	1%
FRCC	86	86	86	86	0%	0%	0%
MISW	77	78	78	78	1%	1%	1%
MISC	70	71	71	71	1%	1%	1%
MISE	94	95	95	95	1%	1%	1%
MISS	69	68	69	69	0%	0%	0%
ISNE	161	161	161	161	0%	0%	0%
NYCW	227	229	229	229	1%	1%	1%
NYUP	128	129	129	129	1%	1%	1%
PJME	116	116	116	116	0%	0%	0%
PJMW	87	87	87	87	1%	1%	1%
PJMC	76	77	77	77	0%	0%	0%
PJMD	74	74	74	74	0%	0%	0%
SRCA	87	87	87	87	0%	0%	0%
SRSE	84	85	85	85	1%	1%	1%
SRCE	64	65	65	65	1%	1%	1%
SPPS	65	66	66	66	1%	1%	2%
SPPC	70	71	71	71	1%	1%	1%
SPPN	63	65	65	66	3%	3%	3%
SRSG	94	95	95	95	1%	1%	1%
CANO	141	141	141	141	0%	0%	0%
CASO	171	171	171	171	0%	0%	0%
NWPP	82	84	84	84	3%	3%	3%
RMRG	83	85	85	85	2%	2%	2%
BASN	94	95	95	95	2%	1%	2%
NATIONAL	92	93	93	93	0.7%	0.6%	0.7%

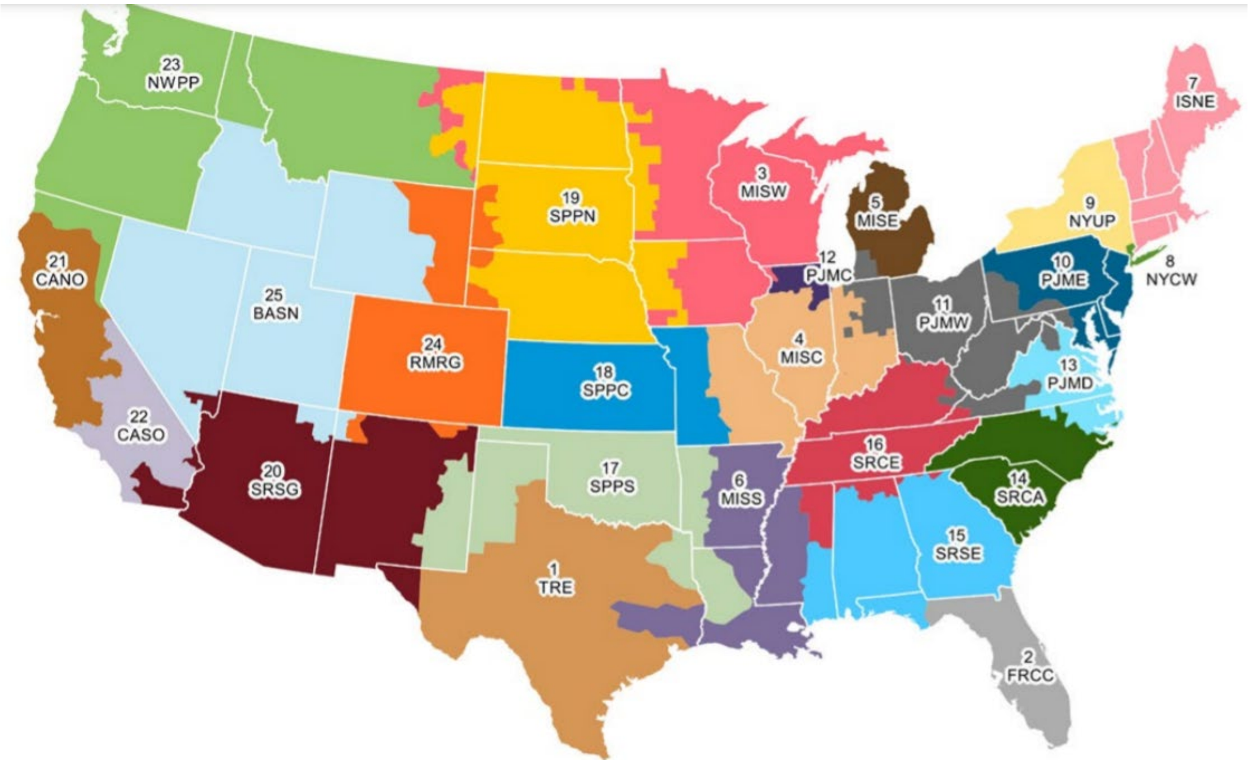

Figure 3-3 Electricity Market Module Regions
Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

3.7 Limitations

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 rules for EGUs, as quantified here, is EPA's best assessment of the cost of implementing the rules for the power sector. These costs are generated from rigorous economic modeling of anticipated changes in the power sector due to implementation of the rule.

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. This is based on AEO 2023 reference case with incremental demand from EPA's OTAQ's on the books rules that are not captured in AEO 2023 reference case projections.[93] To the extent electric demand is higher or lower, it may increase/decrease the projected future thermal/renewable composition of the fleet. Hence higher demand, all else equal, may result in fewer baseline retirements, while a different load shape could incentivize different levels of RE penetration.

- Natural gas supply and demand: The baseline includes significant growth in LNG exports, driving tighter natural gas prices relative to the forecast used to estimate the impacts of the final rules. 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, RE 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. In order to illustrate the impact of the IRA on this rulemaking, EPA included a baseline that incorporates key provisions of the IRA as well as imposing the final rules as modeled in this RIA on that baseline. However, additional effects of the IRA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes.[94]

- Hydrogen production: Currently, hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1.15/kg. The model does not track any upstream emissions[95] associated with the production of the hydrogen, nor any incremental electricity demand associated with its production.[96] The incorporation of these effects could change the amount of hydrogen selected as a compliance measure. The model

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[93] For details, see chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling

[94] For details of IRA representation in this analysis please see IPM documentation, available at: https://www.epa.gov/power-sector-modeling

[95] IPM does not track upstream emissions for any modeled fuels.

[96] Potential impacts associated with hydrogen production and utilization are discussed in preamble Sections VII(F)(3), and XIV(E)(3). These include water use in hydrogen production, combustibility, and potential increased NO_X emissions from combustion of higher percentages of hydrogen in natural gas blends. Analysis in this RIA does not assess these potential impacts, nor the potential impacts of hydrogen gas release on climate or air quality through atmospheric chemical reactions.

also does not account for any possible increases in NO_X emission rates at higher levels of hydrogen blending.[97] For details on hydrogen modeling assumptions, please see Section 3.5.2.

The baseline includes modeling to capture the finalized 2020 Effluent Limitation Guidelines (ELG), and 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 in an updated baseline scenario, which could affect modeled costs and benefits of the rules 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. It is possible that the waste streams of coal plants are subject to multiple rules listed above, and that the interactions between these requirements may alter compliance behavior that would likely occur under any of the rules in isolation, i.e. plants may adopt compliance methods that are different than those represented in the baseline. In order to estimate the impact of recently finalized EPA regulations, sensitivity analysis was performed using IPM and included in the docket for this rulemaking that included a characterization of the LDV, MDV and HDV (2024) vehicle rules, ELG (2024), and MATS (2024) rules in addition to the final carbon rules presented in this RIA.

The impact of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review[98] 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 this program would likely result in a modest increase in the total cost of compliance for this rule. The proposed GNP Supplemental Rule (2023), the proposed Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2023), the proposed Heavy-duty Greenhouse Gas “Phase 3” for Model Years 2027 and Later (2023), the proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility

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[97] For details on the possible increases in NOx emission rates at higher levels of hydrogen blending, please see the *Hydrogen in Combustion Turbine Electricity Generating Units TSD,* available in the docket for this rulemaking.

[98] 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

Steam Generating Units Review of the Residual Risk and Technology Review (2023), and the proposed Steam Electric Power Generating Effluent Guidelines (2023) were not included. Inclusion of these rules may result in changes projected compliance outcomes. Additionally, EPA performed a variety of sensitivity analysis looking at lower natural gas prices, higher electricity demand and also higher electricity demand coupled with EPA's additional Power Sector Rules (MATS, ELG and the Final Rules). These sensitivity analyses continue to show that the Final Rules, in the context of higher demand and other pending power sector rules, still demonstrate compliance pathways that respect these NERC reliability considerations and constraints, while achieving significant emissions reductions at reasonable costs. These results are discussed in "IPM Sensitivities Technical MEMO" and "The Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS Technical MEMO" in the docket for this rulemaking.

The IPM modeling of CCS is inclusive of the cost of installation and operating capture technology and includes heat rate and capacity penalties to account for the parasitic load of the capture equipment. The costs also reflect the cost of transport and storage of captured CO_2 based on the distance between CO_2 production and storage sites. One possible area of uncertainty is delays in the time taken to receive necessary permits, which are not modeled in IPM. As laid out in the preamble, EPA has provided flexibilities in order to manage any delays in the process.

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 largely affect the modeling of the baseline and illustrative scenarios similarly, and therefore, the impact on the incremental projections (reflecting the potential costs/benefits of the regulatory alternatives) would be more limited and are not likely to result in notable changes to the assessment of the final NSPS and Emission Guidelines found in this section. While it is important to recognize these key areas of uncertainty, they do not change EPA's overall confidence in the estimated impacts of the illustrative regulatory alternatives presented in this section. 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.

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4 BENEFITS ANALYSIS

4.1 Introduction

The final rules are expected to reduce emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), and hazardous air pollutants (HAP) including mercury (Hg) nationally over the period of the analysis. While there are national reductions in NO_X, SO_2, and $PM_{2.5}$ emissions that generally leads to improved air quality, the emissions changes for these pollutants are heterogeneous in space and time leading to heterogeneous impacts for ozone and to a lesser extent for $PM_{2.5}$ concentrations. This section reports the estimated monetized climate and health benefits associated with emission changes for each of the three illustrative scenarios described in prior sections and discusses other unquantified benefits.

This section describes the methods used to estimate the climate benefits of GHG emissions reductions expected from the final rules using estimates of the social cost of greenhouse gases (SC-CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). 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 and 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 CO_2 by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2 emissions.

This section also describes the methods used to estimate the benefits to human health of the changes in concentrations of ozone and $PM_{2.5}$ from EGUs. This analysis uses methodology for determining air quality changes that has been used in the RIAs from multiple previous proposed and final rules (U.S. EPA, 2019b, 2020a, 2020b, 2021, 2022c). The approach involves two major steps: (1) developing spatial fields of air quality across the U.S. for baseline and three illustrative scenarios for 2028, 2030, 2035, 2040 and 2045 using nationwide photochemical modeling and related analyses; and (2) using these spatial fields in BenMAP-CE to quantify the benefits under each scenario and each year as compared to the baseline in that year. Health benefit analyses were also run for each year between 2028 and 2047, using the model surfaces for 2028, 2030, 2035, 2040 and 2045 as described in Section 4.3.1, but accounting for the change in population size in each year, income growth and baseline mortality incidence rates at five-year increments. Specifically, the analysis quantifies health benefits resulting from changes in ozone and $PM_{2.5}$ concentrations in 2028, 2030, 2035, 2040 and 2045 for each of the three illustrative scenarios (i.e., final rules, alternative 1 scenario, and alternative 2 scenario). The methods for quantifying the number and value of air pollution-attributable premature deaths and illnesses are described in the Technical Support Document (TSD) titled *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* (U.S. EPA, 2023b) and further referred to as the Health Benefits TSD in this RIA.

Though the final rules are likely to also yield positive benefits associated with reducing pollutants other than CO_2, ozone, and $PM_{2.5}$, time, resource, and data limitations prevented us from characterizing the value of those reductions. Specifically, in this RIA, EPA does not monetize health benefits of reducing direct exposure to NO_2, SO_2 or hazardous air pollutants nor ecosystem effects and visibility impairment associated with changes in air quality. In addition, this RIA does not include monetized benefits from reductions in pollutants in other media, such as water effluents. We qualitatively discuss these unquantified benefits in this section. This RIA also does not quantify impacts of the CCS and hydrogen compliance technologies beyond the direct compliance cost and emissions impacts reflected in Section 3, which is discussed in more detail in Sections 3.7 and 6.

4.2 Climate Benefits

The EPA estimates the climate benefits of CO_2 emissions reductions expected from the final rules using estimates of the social cost of carbon (SC-CO_2) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). The EPA published and used these estimates in the RIA for the December 2023 Final Oil and Gas NSPS/EG Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (U.S. EPA, 2023e). The EPA solicited public comment on the methodology and use of these estimates in the RIA for the agency's December 2022 Oil and Gas NSPS/EG Supplemental Proposal[99] and has conducted an external peer review of these estimates, as described further below.

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 and 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 CO_2 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 restrain the ability of SC-CO_2 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (i.e., SC-CO_2, SC-CH_4, and SC-N_2O), collectively referred to as the "social cost of greenhouse gases" (SC-GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021 – including in the proposal for this rulemaking – have been consistent with those developed and recommended by the Interagency Working Group (IWG) on the SC-GHG; and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015-2017, the National Academies conducted a comprehensive review of the SC-CO_2 and issued a final report in 2017 recommending 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, 2017).

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[99] See https://www.epa.gov/environmental-economics/scghg for a copy of the final report and other related materials.

The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC-GHG estimates, recommendations regarding areas of decision-making to which SC-GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. As noted in previous EPA RIAs, including in the proposal RIA for this rulemaking, 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 [100]. In the December 2022 Oil and Gas NSPS/EG Supplemental Proposal RIA, the Agency included a sensitivity analysis of the climate benefits of the Supplemental Proposal using a new set of SC-GHG estimates that incorporates recent research addressing recommendations of the National Academies (2017) in addition to using the interim SC-GHG estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (2021) that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, which explains the methodology underlying the new set of estimates, in the December 2022 Supplemental Oil and Gas Proposal. The response to comments document can be found in the docket for that action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. See 88 FR at 26075/2 noting this peer review process. The peer reviewers commended the agency on its development of the draft update, calling it a much-needed improvement in estimating the SC-GHG and a significant step towards addressing the National Academies'

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[100] EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on EPA's website.[101]

The remainder of this section provides an overview of the methodological updates incorporated into the SC-GHG estimates used in this final RIA. A more detailed explanation of each input and the modeling process is provided in the final technical report, EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Appendix A shows the benefits of the final rules using the interim SC-GHG (IWG, 2021) estimates presented in the proposal RIA for comparison purposes.

The steps necessary to estimate the SC-GHG with a climate change integrated assessment model (IAM) can generally be grouped into four modules: socioeconomics and emissions, climate, damages, and discounting. The emissions trajectories from the socioeconomic module are used to project future temperatures in the climate module. The damage module then translates the temperature and other climate endpoints (along with the projections of socioeconomic variables) into physical impacts and associated monetized economic damages, where the damages are calculated as the amount of money the individuals experiencing the climate change impacts would be willing to pay to avoid them. To calculate the marginal effect of emissions, i.e., the SC-GHG in year t, the entire model is run twice – first as a baseline and second with an additional pulse of emissions in year t. After recalculating the temperature effects and damages expected in all years beyond t resulting from the adjusted path of emissions, the losses are discounted to a present value in the discounting module. Many sources of uncertainty in the estimation process are incorporated using Monte Carlo techniques by taking draws from probability distributions that reflect the uncertainty in parameters.

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[101] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review*.

The SC-GHG estimates used by the EPA and many other federal agencies since 2009 have relied on an ensemble of three widely used IAMs: Dynamic Integrated Climate and Economy (DICE) (Nordhaus, 2010); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) (Anthoff and Tol, 2013a, 2013b); and Policy Analysis of the Greenhouse Gas Effect (PAGE) (Hope, 2013). In 2010, the IWG harmonized key inputs across the IAMs, but all other model features were left unchanged, relying on the model developers' best estimates and judgments. That is, the representation of climate dynamics and damage functions included in the default version of each IAM as used in the published literature was retained.

The SC-GHG estimates in this RIA no longer rely on the three IAMs (i.e., DICE, FUND, and PAGE) used in previous SC-GHG estimates. As explained previously, EPA uses a modular approach to estimate the SC-GHG, consistent with the National Academies' (2017) near-term recommendations. That is, the methodology underlying each component, or module, of the SC-GHG estimation process is developed by drawing on the latest research and expertise from the scientific disciplines relevant to that component. Under this approach, each step in the SC-GHG estimation improves consistency with the current state of scientific knowledge, enhances transparency, and allows for more explicit representation of uncertainty.

The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future (RFF) Social Cost of Carbon Initiative (Rennert, Prest, et al., 2022). These socioeconomic projections (hereafter collectively referred to as the RFF-SPs) are an internally consistent set of probabilistic projections of population, GDP, and GHG emissions (CO_2, CH_4, and N_2O) to 2300. Based on a review of available sources of long-run projections necessary for damage calculations, the RFF-SPs stand out as being most consistent with the National Academies' recommendations. Consistent with the National Academies' recommendation, the RFF-SPs were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and technological developments, and provide the level of disaggregation necessary for damage calculations. Unlike other sources of projections, they provide inputs for estimation out to 2300 without further extrapolation assumptions. Conditional on the modeling conducted for the SC-GHG estimates, this time horizon is far enough in the future to capture the majority of discounted climate damages. Including damages beyond 2300 would increase the estimates of the SC-GHG. As discussed in U.S. EPA (2023d), the use of the RFF-SPs allows for capturing economic growth uncertainty within the discounting module.

The climate module relies on the Finite Amplitude Impulse Response (FaIR) model, (IPCC, 2021b; Millar et al., 2017; C. J. Smith et al., 2018) a widely used Earth system model which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature. The FaIR model was originally developed by Richard Millar, Zeb Nicholls, and Myles Allen at Oxford University, as a modification of the approach used in IPCC AR5 to assess the GWP and GTP (Global Temperature Potential) of different gases. It is open source, widely used (e.g., IPCC (2018, 2021a) and was highlighted by the National Academies (2017) as a model that satisfies their recommendations for a near-term update of the climate module in SC-GHG estimation. Specifically, it translates GHG emissions into mean surface temperature response and represents the current understanding of the climate and GHG cycle systems and associated uncertainties within a probabilistic framework. The SC-GHG estimates used in this RIA rely on FaIR version 1.6.2 as used by the IPCC (2021a, 2021b). It provides, with high confidence, an accurate representation of the latest scientific consensus on the relationship between global emissions and global mean surface temperature and offers a code base that is fully transparent and available online. The uncertainty capabilities in FaIR 1.6.2 have been calibrated to the most recent assessment of the IPCC (which importantly narrowed the range of likely climate sensitivities relative to prior assessments). See U.S. EPA (2022f) for more details.

The socioeconomic projections and outputs of the climate module are inputs into the damage module to estimate monetized future damages from climate change[102]. The National Academies' recommendations for the damage module, scientific literature on climate damages, updates to models that have been developed since 2010, as well as the public comments received on individual EPA rulemakings and the IWG's February 2021 TSD, have all helped to identify available sources of improved damage functions. The IWG (e.g., IWG (2010, 2016a, 2021)), the

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[102] In addition to temperature change, two of the three damage modules used in the SC-GHG estimation require global mean sea level (GMSL) projections as an input to estimate coastal damages. Those two damage modules use different models for generating estimates of GMSL. Both are based off reduced complexity models that can use the FaIR temperature outputs as inputs to the model and generate projections of GMSL accounting for the contributions of thermal expansion and glacial and ice sheet melting based on recent scientific research. Absent clear evidence on a preferred model, the SC-GHG estimates presented in this RIA retain both methods used by the damage module developers. See U.S. EPA (2023d) for more details.

National Academies (2017), comprehensive studies (e.g., Rose et al. (2014)), and public comments have all recognized that the damages functions underlying the IWG SC-GHG estimates used since 2013 (taken from DICE 2010 (Nordhaus, 2010); FUND 3.8 (Anthoff and Tol, 2013b); and PAGE 2009 (Hope, 2013)) do not include all the important physical, ecological, and economic impacts of climate change. The climate change literature and the science underlying the economic damage functions have evolved, and DICE 2010, FUND 3.8, and PAGE 2009 now lag behind the most recent research.

The challenges involved with updating damage functions have been widely recognized. Functional forms and calibrations are constrained by the available literature and need to extrapolate beyond warming levels or locations studied in that literature. Research and public resources focused on understanding how these physical changes translate into economic impacts have been significantly less than the resources focused on modeling and improving our understanding of climate system dynamics and the physical impacts from climate change (Auffhammer, 2018). Even so, there has been a large increase in research on climate impacts and damages in the time since DICE 2010, FUND 3.8, and PAGE 2009 were published. Along with this growth, there continues to be wide variation in methodologies and scope of studies, such that care is required when synthesizing the current understanding of impacts or damages. Based on a review of available studies and approaches to damage function estimation, the EPA uses three separate damage functions to form the damage module. They are:

A subnational-scale, sectoral damage function (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (Carleton, 2022; CIL, 2023; Rode et al., 2021), a country-scale, sectoral damage function (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF’s Social Cost of Carbon Initiative (Rennert, Prest, et al., 2022), and a meta-analysis-based damage function (based on Howard and Sterner (2017)). The damage functions in DSCIM and GIVE represent substantial improvements relative to the damage functions underlying the SC-GHG estimates used by the EPA to date and reflect the forefront of scientific understanding about how temperature change and SLR lead to monetized net (market and nonmarket) damages for several categories of climate impacts. The models’ spatially explicit and impact-specific modeling of relevant processes allow for improved understanding and transparency about mechanisms through which climate impacts are occurring and how each damage component contributes to the overall results, consistent with the National

Academies' recommendations. DSCIM addresses common criticisms related to the damage functions underlying current SC-GHG estimates (e.g., (Pindyck, 2017)) by developing multi-sector, empirically grounded damage functions. The damage functions in the GIVE model offer a direct implementation of the National Academies' near-term recommendation to develop updated sectoral damage functions that are based on recently published work and reflective of the current state of knowledge about damages in each sector. Specifically, the National Academies noted that "[t]he literature on agriculture, mortality, coastal damages, and energy demand provide immediate opportunities to update the [models]" (National Academies, 2017), which are the four damage categories currently in GIVE. A limitation of both models is that the sectoral coverage is still limited, and even the categories that are represented are incomplete. Neither DSCIM nor GIVE yet accommodate estimation of several categories of temperature driven climate impacts (e.g., morbidity, conflict, migration, biodiversity loss) and only represent a limited subset of damages from changes in precipitation. For example, while precipitation is considered in the agriculture sectors in both DSCIM and GIVE, neither model takes into account impacts of flooding, changes in rainfall from tropical storms, and other precipitation related impacts. As another example, the coastal damage estimates in both models do not fully reflect the consequences of SLR-driven salt-water intrusion and erosion, or SLR damages to coastal tourism and recreation. Other missing elements are damages that result from other physical impacts (e.g., ocean acidification, non-temperature-related mortality such as diarrheal disease and malaria) and the many feedbacks and interactions across sectors and regions that can lead to additional damages[103]. See U.S. EPA (2023c) for more discussion of omitted damage categories and other modeling limitations. DSCIM and GIVE do account for the most commonly cited benefits associated with CO_2 emissions and climate change – CO_2 crop fertilization and declines in cold related mortality. As such, while the GIVE- and DSCIM-based results provide state-of-the-science assessments of key climate change impacts, they remain partial estimates of future climate damages resulting from incremental changes in CO2, CH4, and N2O[104].

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[103] The one exception is that the agricultural damage function in DSCIM and GIVE reflects the ways that trade can help mitigate damages arising from crop yield impacts.

[104] One advantage of the modular approach used by these models is that future research on new or alternative damage functions can be incorporated in a relatively straightforward way. DSCIM and GIVE developers have work underway on other impact categories that may be ready for consideration in future updates (e.g., morbidity and biodiversity loss).

Finally, given the still relatively narrow sectoral scope of the recently developed DSCIM and GIVE models, the damage module includes a third damage function that reflects a synthesis of the state of knowledge in other published climate damages literature. Studies that employ meta-analytic techniques[105] offer a tractable and straightforward way to combine the results of multiple studies into a single damage function that represents the body of evidence on climate damages that pre-date CIL and RFF's research initiatives. The first use of meta-analysis to combine multiple climate damage studies was done by Tol (2009) and included 14 studies. The studies in Tol (2009) served as the basis for the global damage function in DICE starting in version 2013R (Nordhaus, 2014) The damage function in the most recent published version of DICE, DICE 2016, is from an updated meta-analysis based on a review of existing damage studies and included 26 studies published over 1994-2013 (Nordhaus and Moffat, 2017). Howard and Sterner (2017) provide a more recent published peer-reviewed meta-analysis of existing damage studies (published through 2016) and account for additional features of the underlying studies. This study address differences in measurement across studies by adjusting estimates such that the data are relative to the same base period. They also eliminate double counting by removing duplicative estimates. Howard and Sterner's final sample is drawn from 20 studies that were published through 2015. Howard and Sterner (2017) present results under several specifications and shows that the estimates are somewhat sensitive to defensible alternative modeling choices. As discussed in detail in U.S. EPA (2023d), the damage module underlying the SC-GHG estimates in this RIA includes the damage function specification (that excludes duplicate studies) from Howard and Sterner (2017) that leads to the lowest SC-GHG estimates, all else equal.

The discounting module discounts the stream of future net climate damages 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. Consistent with the findings of (National Academies, 2017), the economic literature, OMB Circular A-4's guidance for regulatory analysis, and IWG recommendations to date (IWG, 2010, 2013, 2016a, 2016b, 2021; *Technical Support Document:*

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[105] Meta-analysis is a statistical method of pooling data and/or results from a set of comparable studies of a problem. Pooling in this way provides a larger sample size for evaluation and allows for a stronger conclusion than can be provided by any single study. Meta-analysis yields a quantitative summary of the combined results and current state of the literature.

Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866, 2010), the EPA continues to conclude that the consumption rate of interest is the theoretically appropriate discount rate to discount the future benefits of reducing GHG emissions and that discount rate uncertainty should be accounted for in selecting future discount rates in this intergenerational context. OMB's Circular A-4 points out that "the analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption and to discount them at the rate consumers and savers would normally use in discounting future consumption benefits" (OMB, 2003). [106] The damage module described above calculates future net damages in terms of reduced consumption (or monetary consumption equivalents), and so an application of this guidance is to use the consumption discount rate to calculate the SC-GHG. Thus, EPA concludes that the use of the social rate of return on capital (7 percent under the 2003 OMB Circular A-4 guidance), which does not reflect the consumption rate, to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG[107].

For the SC-GHG estimates used in this RIA, EPA relies on a dynamic discounting approach that more fully captures the role of uncertainty in the discount rate in a manner consistent with the other modules. Based on a review of the literature and data on consumption discount rates, the public comments received on individual EPA rulemakings, and the February 2021 TSD (IWG, 2021), and the National Academies (2017) recommendations for updating the discounting module, the SC-GHG estimates rely on discount rates that reflect more recent data on the consumption interest rate and uncertainty in future rates. Specifically, rather than using a constant discount rate, the evolution of the discount rate over time is defined following the latest empirical evidence on interest rate uncertainty and using a framework originally developed by Ramsey (1928) that connects economic growth and interest rates. The Ramsey approach explicitly reflects (1) preferences for utility in one period relative to utility in a later period and (2) the value of additional consumption as income changes. The dynamic discount rates used to

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106 Similarly, OMB's Circular A-4 (2023) points out that "The analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption before discounting them".

107 See also the discussion of the inappropriateness of discounting consumption-equivalent measures of benefits and costs using a rate of return on capital in Circular A-4 (OMB, 2003).

develop the SC-GHG estimates applied in this RIA have been calibrated following the Newell et al. (2022) approach, as applied in Rennert, Errickson, et al. (2022); Rennert, Prest, et al. (2022). This approach uses the discounting formula Ramsey (1928) in which the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020, 2023) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest. Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates.

The resulting dynamic discount rate provides a notable improvement over the constant discount rate framework used for SC-GHG estimation in previous EPA RIAs. Specifically, it provides internal consistency within the modeling and a more complete accounting of uncertainty consistent with economic theory (Arrow et al., 2013; Cropper et al., 2014) and the National Academies (2017) recommendation to employ a more structural, Ramsey-like approach to discounting that explicitly recognizes the relationship between economic growth and discounting uncertainty. This approach is also consistent with the National Academies (2017) recommendation to use three sets of Ramsey parameters that reflect a range of near-term certainty-equivalent discount rates and are consistent with theory and empirical evidence on consumption rate uncertainty. Finally, the value of aversion to risk associated with net damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. See U.S. EPA (2022f) for a more detailed discussion of the entire discounting module and methodology used to value risk aversion in the SC-GHG estimates.

Taken together, the methodologies adopted in this SC-GHG estimation process allow for a more holistic treatment of uncertainty than past estimates used by the EPA. The updates incorporate a quantitative consideration of uncertainty into all modules and use a Monte Carlo approach that captures the compounding uncertainties across modules. The estimation process generates nine separate distributions of discounted marginal damages per metric ton – the product of using three damage modules and three near-term target discount rates – for each gas in each emissions year. These distributions have long right tails reflecting the extensive evidence in the scientific and economic literature that shows the potential for lower-probability but higher-impact outcomes from climate change, which would be particularly harmful to society. The uncertainty grows over the modeled time horizon. Therefore, under cases with a lower near-term target discount rate – that give relatively more weight to impacts in the future – the distribution of results is wider. To produce a range of estimates that reflects the uncertainty in the estimation exercise while also providing a manageable number of estimates for policy analysis, the EPA combines the multiple lines of evidence on damage modules by averaging the results across the three damage module specifications. The full results generated from the updated methodology for methane and other greenhouse gases (SC-CO_2, SC-CH_4, and SC-N_2O) for emissions years 2020 through 2080 are provided in U.S. EPA (2023d).

Table 4-1 summarizes the resulting averaged certainty-equivalent SC-CO_2 estimates under each near-term discount rate that are used to estimate the climate benefits of the CO_2 emission reductions expected from the final rules. These estimates are reported in 2019 dollars but are otherwise identical to those presented in U.S. EPA (2023e). 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 2028 — 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.

Table 4-1 Estimates of the Social Cost of CO_2 Values, 2028-2047 (2019 dollars per Metric Ton CO_2) [a]

	Near-term Ramsey Discount Rate		
Emission Year	**2.5%**	**2%**	**1.5%**
2028	140	220	370
2029	140	220	380
2030	140	230	380
2031	150	230	380
2032	150	230	390
2033	150	240	390
2034	150	240	400
2035	160	240	400
2036	160	250	410
2037	160	250	410
2038	160	260	420
2039	170	260	420
2040	170	260	430
2041	170	270	430
2042	180	270	440
2043	180	280	440
2044	180	280	450
2045	190	280	450
2046	190	290	460
2047	190	290	460

[a] Source: U.S. EPA (2023e).

Note: These SC-CO_2 values are identical to those reported in the technical report (U.S. EPA, 2023e) adjusted to 2019 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, 2022) rounded to 2 significant figures. The values are stated in $/metric ton CO_2 and vary depending on the year of CO_2 emissions. This table displays the values rounded to two significant figures. The annual unrounded values used in the calculations in this RIA are available in Appendix A.4 of U.S. EPA (2023e) and at: www.epa.gov/environmental-economics/scghg.

The methodological updates described above represent a major step forward in bringing SC-GHG estimation closer to the frontier of climate science and economics and address many of the National Academies' (2017) near-term recommendations. Nevertheless, the resulting SC-CO_2 estimates presented in Table 4-1, still have several limitations, as would be expected for any modeling exercise that covers such a broad scope of scientific and economic issues across a complex global landscape. There are still many categories of climate impacts and associated damages that are only partially or not reflected yet in these estimates and sources of uncertainty that have not been fully characterized due to data and modeling limitations. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions. Importantly, the updated SC-GHG methodology does not yet reflect interactions and feedback effects within, and across, Earth and human systems. For example, it does not explicitly reflect potential interactions among damage categories, such as those stemming from the interdependencies of energy, water, and land use. These, and other, interactions and feedbacks were highlighted by the National Academies as an important area of future research for longer-term enhancements in the SC-GHG estimation framework.

Table 4-2 presents the estimated reductions in CO_2 emissions from the final rules, and Table 4-3 presents the associated estimated annual, undiscounted climate benefits using the SC-CO_2 estimates presented in Table 4-1 for the stream of years beginning in 2028 through 2047. Also shown in Table 4-3 are the present value (PV) of monetized climate benefits discounted back to 2024 and equivalent annualized values (AV) associated with each of the three SC-CO_2 values. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the near-term target Ramsey rate used to discount the climate benefits from future CO_2 reductions. To calculate the present and annualized values of climate benefits in Table 4-3, EPA uses the same discount rate as the near-term target Ramsey rate used to discount the climate benefits from future CO_2 reductions. [108] That is, future climate benefits estimated with the SC-CO_2 at the near-term 2.5, 2 , and 1.5 percent Ramsey rate are discounted to the base year of the analysis using a constant 2.5, 2, and 1.5 percent rate, respectively.

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[108] As discussed in U.S. EPA (2023d) the error associated with using a constant discount rate rather than the certainty-equivalent rate path to calculate the present value of a future stream of monetized climate benefits is small for analyses with moderate time frames (e.g., 30 years or less). EPA (2023d) also provides an illustration of the amount that climate benefits from reductions in future emissions will be underestimated by using a constant discount rate relative to the more complicated certainty-equivalent rate path.

Table 4-2 Annual CO_2 Emissions Reductions (million metric tons) for the Illustrative Scenarios from 2028 through 2047

	Million Metric Tons of CO_2		
Emission Year	Final Rules	Alternative 1	Alternative 2
2028	38	36	32
2029	38	36	32
2030	50	48	27
2031	50	48	27
2032	123	124	122
2033	123	124	122
2034	123	124	122
2035	123	124	122
2036	123	124	122
2037	123	124	122
2038	54	53	53
2039	54	53	53
2040	54	53	53
2041	54	53	53
2042	42	40	40
2043	42	40	40
2044	42	40	40
2045	42	40	40
2046	42	40	40
2047	42	40	40
Total	1,382	1,365	1,303

Table 4-3 Estimated Climate Benefits of Reduced CO_2 Emissions from the Illustrative Scenarios, 2028 to 2047 (billions of 2019 dollars)

	Final Rules			**Alternative 1**			**Alternative 2**		
	Near-term Ramsey Discount Rate			Near-term Ramsey Discount Rate			Near-term Ramsey Discount Rate		
	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2028	5.2	8.4	14	4.9	7.9	13	4.4	7.1	12
2029	5.3	8.5	14	5	8	14	4.5	7.2	12
2030	7.1	11	19	6.8	11	18	3.9	6.2	10
2031	7.2	12	19	7	11	18	4	6.3	11
2032	18	29	48	18	29	48	18	28	47
2033	19	29	48	19	29	49	18	29	48
2034	19	30	49	19	30	49	19	29	48
2035	19	30	50	19	30	50	19	30	49
2036	20	31	50	20	31	50	19	30	49
2037	20	31	51	20	31	51	20	31	50
2038	8.8	14	22	8.8	14	22	8.7	14	22
2039	9	14	23	9	14	22	8.9	14	22
2040	9.1	14	23	9.1	14	23	9	14	23
2041	9.3	14	23	9.3	14	23	9.2	14	23
2042	7.4	11	18	7.1	11	17	7.1	11	18
2043	7.5	12	18	7.2	11	18	7.2	11	18
2044	7.7	12	19	7.4	11	18	7.4	11	18
2045	7.8	12	19	7.5	11	18	7.5	11	18
2046	8	12	19	7.6	12	18	7.6	12	18
2047	8.1	12	19	7.7	12	19	7.8	12	19
PV	**160**	**270**	**470**	**160**	**270**	**460**	**150**	**250**	**440**
EAV	**9**	**14**	**23**	**9**	**14**	**23**	**8.6**	**13**	**22**

Note: Values have been rounded to two significant figures.

Unlike many environmental problems where the causes and impacts are distributed more locally, GHG emissions are a global externality making climate change a true global challenge. GHG emissions contribute to damages around the world regardless of where they are emitted. Because of the distinctive global nature of climate change, in the RIA for these final rules the EPA centers attention on a global measure of climate benefits from GHG reductions. Consistent with all IWG recommended SC-GHG estimates to date, the SC-CO_2 values presented Table 4-1 provide a global measure of monetized damages from CO_2 and Table 4-3 presents the monetized global climate benefits of the CO_2 emission reductions expected from the final rules. This approach is the same as that taken in EPA regulatory analyses from 2009 through 2016 and since 2021. It is also consistent with guidance in OMB Circular A-4 (OMB 2003, 2023) that recommends reporting of important international effects.[109] EPA also notes that EPA's cost estimates in RIAs, including the cost estimates contained in this RIA, regularly do not differentiate between the share of compliance costs expected to accrue to U.S. firms versus foreign interests, such as to foreign investors in regulated entities.[110] A global perspective on climate effects is therefore consistent with the approach EPA takes on costs. There are many reasons, as summarized in this section – and as articulated by OMB and in IWG assessments (2010, 2013, 2016a, 2016b, 2021), the 2015 Response to Comments (IWG, 2015), and in detail in U.S. EPA (2023c), and in Appendix A of the Response to Comments document for the December 2023 Final Oil and Gas NSPS/EG Rulemaking – why the EPA focuses on the global value of climate change impacts when analyzing policies that affect GHG emissions.

International cooperation and reciprocity are essential to successfully addressing climate change, as the global nature of greenhouse gases means that a ton of GHGs emitted in any other country harms those in the U.S. just as much as a ton emitted within the territorial U.S.

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[109] The 2003 version of OMB Circular A-4 states when a regulation is likely to have international effects, "these effects should be reported"; while OMB Circular A-4 recommends that international effects we reported separately, the guidance also explains that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." (OMB, 2003).

The 2023 update to Circular A-4 states that "In certain contexts, it may be particularly appropriate to include effects experienced by noncitizens residing abroad in your primary analysis. Such contexts include, for example, when:

- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. citizens and residents that are difficult to otherwise estimate;
- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. national interests that are not otherwise fully captured by effects experienced by particular U.S. citizens and residents (e.g., national security interests, diplomatic interests, etc.);
- regulating an externality on the basis of its global effects supports a cooperative international approach to the regulation of the externality by potentially inducing other countries to follow suit or maintain existing efforts; or
- international or domestic legal obligations require or support a global calculation of regulatory effects" (OMB 2023). Due to the global nature of the climate change problem, the OMB recommendations of appropriate contexts for considering international effects are relevant to the CO_2 emission reductions expected from the final rule. For example, as discussed in this RIA, a global focus in evaluating the climate impacts of changes in CO_2 emissions supports a cooperative international approach to GHG mitigation by potentially inducing other countries to follow suit or maintain existing efforts, and the global SC-CO_2 estimates better capture effects on U.S. citizens and residents and U.S. national interests that are difficult to estimate and not otherwise fully captured.

[110] For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, EPA acknowledged that some portion of regulatory costs will likely "accru[e] to entities outside U.S. borders" through foreign ownership, employment, or consumption (EPA 2018, p. 3-13). In general, a significant share of U.S. corporate debt and equities are foreign-owned, including in the oil and gas industry.

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. This is a classic public goods problem because each country's reductions benefit everyone else, and no country can be excluded from enjoying the benefits of other countries' reductions. 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 and residents — is for all countries to base their policies on global estimates of damages. A wide range of scientific and economic experts have emphasized the issue of international cooperation and reciprocity as support for assessing global damages of GHG emission in domestic policy analysis. 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 also assess global climate damages of their policies and to take steps to reduce emissions. For example, many countries and international institutions have already explicitly adapted the global SC-GHG estimates used by EPA in their domestic analyses (e.g., Canada, Israel) or developed their own estimates of global damages (e.g., Germany), and recently, there has been renewed interest by other countries to update their estimates since the draft release of the updated SC-GHG estimates presented in the December 2022 Oil and Gas NSPS/EG Supplemental Proposal RIA.[111] Several recent studies have empirically examined the evidence on international GHG mitigation reciprocity, through both policy diffusion and technology diffusion effects. See U.S. EPA (2022f) for more discussion.

For all of these reasons, the EPA believes that a global metric is appropriate for assessing the climate benefits of avoided GHG emissions in this final RIA. In addition, as emphasized in the National Academies (2017) recommendations, "[i]t is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States." The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need

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[111] In April 2023, the government of Canada announced the publication of an interim update to their SC-GHG guidance, recommending SC-GHG estimates identical to EPA's updated estimates presented in the December 2022 Supplemental Proposal RIA. The Canadian interim guidance will be used across all Canadian federal departments and agencies, with the values expected to be finalized by the end of the year. https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html.

to be considered when evaluating the benefits of GHG mitigation to U.S. citizens and residents. The increasing interconnectedness of global economy and populations means that impacts occuring outside of U.S. borders can have significant impacts on U.S. interests. 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 point to the global nature of the climate change problem and are better captured within global measures of the social cost of greenhouse gases.

In the case of these global pollutants, for the reasons articulated in this section, the assessment of global net damages of GHG emissions allows EPA to fully disclose and contextualize the net climate benefits of CO_2 emission reductions expected from these final rules. The EPA disagrees with public comments received on the December 2022 Oil and Gas NSPS/EG Supplemental Proposal that suggested that the EPA can or should use a metric focused on benefits resulting solely from changes in climate impacts occuring within U.S. borders. The global models used in the SC-GHG modeling described above do not lend themselves to be disaggregated in a way that could provide sufficiently robust information about the distribution of the rule's climate benefits to citizens and residents of particular countries, or population groups across the globe and within the U.S. Two of the models used to inform the damage module, the GIVE and DSCIM models, have spatial resolution that allows for some geographic disaggregation of future climate impacts across the world. This permits the calculation of a partial GIVE and DSCIM-based SC-GHG measuring the damages from four or five climate impact categories projected to physically occur within the U.S., respectively, subject to caveats. As discussed at length in U.S. EPA (2023c), these damage modules are only a partial accounting and do not capture all of the pathways through which climate change affects public health and welfare. For example, this modeling omits most of the consequences of changes in precipitation, damages from extreme weather events (e.g., wildfires), the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions other than CO_2 fertilization (e.g., tropospheric ozone formation due to CH_4 emissions). Thus, they only cover a subset of potential climate change impacts. Furthermore, as discussed at length in U.S. EPA (2023d), the damage modules do not capture spillover or indirect effects whereby climate impacts in one country or region can affect the welfare of residents in other countries or regions—such as how economic and health conditions across countries will impact U.S. business, investments, and travel abroad.

Additional modeling efforts can and have shed further light on some omitted damage categories. For example, the Framework for Evaluating Damages and Impacts (FrEDI) is an open-source modeling framework developed by the EPA[112] to facilitate the characterization of net annual climate change impacts in numerous impact categories within the contiguous U.S. and monetize the associated distribution of modeled damages (Sarofim et al., 2021; U.S. EPA, 2021). The additional impact categories included in FrEDI reflect the availability of U.S.-specific data and research on climate change effects. As discussed in U.S. EPA (2023c) results from FrEDI show that annual damages resulting from climate change impacts within the contiguous U.S. (CONUS) (i.e., excluding Hawaii, Alaska, and U.S. territories) and for impact categories not represented in GIVE and DSCIM are expected to be substantial. As discussed in U.S. EPA (2021), results from FrEDI show that annual damages resulting from climate change impacts within the contiguous U.S. (CONUS) (i.e., excluding Hawaii, Alaska, and U.S. territories) and for impact categories not represented in GIVE and DSCIM are expected to be substantial. For example, FrEDI estimates a partial SC-CO_2 of \$36/mtCO_2 for damages physically occurring within CONUS for 2030 emissions (under a 2 percent near-term Ramsey discount rate) (Hartin, et al. 2023), compared to a GIVE and DSCIM-based U.S.-specific SC-CO_2 of \$16/mtCO_2 and \$14/mtCO_2, respectively, for 2030 emissions (2019 dollars). While the FrEDI results help to illustrate how monetized damages physically occurring within CONUS increase as more impacts are reflected in the modeling framework, they are still subject to many of the same limitations associated with the DSCIM and GIVE damage modules, including the omission or partial modeling of important damage categories.[113] Finally, none of these modeling efforts – GIVE,

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[112] The FrEDI framework and Technical Documentation have been subject to a public review comment period and an independent external peer review, following guidance in the EPA Peer-Review Handbook for Influential Scientific Information (ISI). Information on the FrEDI peer-review is available at the EPA Science Inventory (EPA Science Inventory, 2021).

[113] Another method that has produced estimates of the effect of climate change on U.S.-specific outcomes uses a top-down approach to estimate aggregate damage functions. Published research using this approach include total-economy empirical studies that econometrically estimate the relationship between GDP and a climate variable, usually temperature. As discussed in U.S. EPA (2023d) the modeling framework used in the existing published studies using this approach differ in important ways from the inputs underlying the SC-GHG estimates described above (e.g., discounting, risk aversion, and scenario uncertainty). Hence, we do not consider this line of evidence in the analysis for this RIA. Updating the framework of total-economy empirical damage functions to be consistent with the methods described in this RIA and U.S. EPA (2023d) would require new analysis. Finally,

DSCIM, and FrEDI – reflect non-climate mediated effects of GHG emissions experienced by U.S. populations (other than CO_2 fertilization effects on agriculture).

Applying the U.S.-specific partial SC-GHG estimates derived from the multiple lines of evidence described above to the GHG emissions reduction expected under the final rules would yield substantial benefits. For example, the present value of the climate benefits of the final rules over 2024 - 2047 as measured by FrEDI from climate change impacts in CONUS are estimated to be $42 billion (under a 2 percent near-term Ramsey discount rate). However, the numerous explicitly omitted damage categories and other modeling limitations discussed above and throughout U.S. EPA (2023c) make it likely that these estimates underestimate the benefits to U.S. citizens and residents of the GHG reductions from the final rule; the limitations in developing a U.S.-specific estimate that accurately captures direct and spillover effects on U.S. citizens and residents further demonstrates that it is more appropriate to use a global measure of climate benefits from GHG reductions. The EPA 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 GHG impacts.

4.3 Human Health Benefits

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 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 risk change, 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.[114] We conduct this analysis by adapting

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because total-economy empirical studies estimate market impacts, they do not include any non-market impacts of climate change (e.g., heat related mortality) and therefore are also only a partial estimate. EPA will continue to review developments in the literature and explore ways to better inform the public of the full range of GHG impacts.

[114] 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

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) developing spatial fields of air quality for baseline and three illustrative scenarios (2) selecting air pollution health endpoints to quantify; (3) calculating counts of air pollution effects using a health impact function; (4) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature to calculate the economic value of the health impacts. We estimate the quantity and economic value of air pollution-related effects using a "damage-function." This approach quantifies counts of air pollution-attributable cases of adverse health outcomes and assigns dollar values to those counts, while assuming that each outcome is independent of one another.

As structured, these final rules would affect the distribution of ozone and $PM_{2.5}$ concentrations in much of the U.S. This RIA estimates 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, 2015c, 2022d). 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 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 emissions control measures. The benefit estimates are based on these modeled changes in $PM_{2.5}$ and summer season average ozone concentrations for each of the years 2028, 2030, 2035, 2040 and 2045.

4.3.1 Air Quality Modeling Methodology and Results

The final rules influence the level of pollutants emitted in the atmosphere that adversely affect human health, including directly emitted $PM_{2.5}$, as well as SO_2 and NO_X, which are both precursors to ambient $PM_{2.5}$. NO_X emissions are also a precursor to ambient ground-level ozone. EPA used air quality modeling to estimate changes in ozone and $PM_{2.5}$ concentrations that may occur as a result of the three illustrative scenarios for the final rules relative to the baseline.

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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.

As described in the Air Quality Modeling Appendix (Appendix B), gridded spatial fields of ozone and $PM_{2.5}$ concentrations representing the baseline and three illustrative scenarios were derived from CAMx source apportionment modeling in combination with NO_X, SO_2, and primary $PM_{2.5}$ EGU emissions obtained from the outputs of the IPM runs described in Section 3 of this RIA. The air quality modeling includes all inventoried pollution sources in the contiguous U.S., contributions from all sources other than EGUs are held constant at projected 2026 levels in this analysis, and the only changes quantified between the baseline and three illustrative scenarios are those associated with the projected impacts of the final rules on EGU emissions. EPA prepared gridded spatial fields of air quality for the baseline and the three illustrative scenarios for two health-impact metrics: annual mean $PM_{2.5}$ and April through September seasonal average 8-hour daily maximum (MDA8) ozone (AS-MO3). These ozone and $PM_{2.5}$ gridded spatial fields cover all locations in the contiguous U.S. and were used as inputs to BenMAP-CE[115] which, in turn, was used to quantify the benefits from the final rules.

The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (U.S. EPA, 2019b, 2020a, 2020b, 2021, 2022c). The Air Quality Modeling Appendix (Appendix B) provides additional details on the air quality modeling and the methodologies EPA used to develop gridded spatial fields of summertime ozone and annual $PM_{2.5}$ concentrations.

The Air Quality Modeling Appendix also provides figures showing the geographical distribution of air quality changes in the illustrative scenarios relative to the baseline. The spatial fields of baseline AS-MO3 and Annual Average $PM_{2.5}$ and changes in the illustrative policy scenarios relative to the baseline in 2028, 2030, 2035, 2040 and 2045 are presented in Figure B-8 through Figure B-17. The spatial patterns shown in the figures are a result of (1) of the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) of the physical or chemical processing that the model simulates in the atmosphere. In all years, the final rules are expected to result in reductions in ozone concentrations over many areas of the US,

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[115] EPA recently convened a Scientific Advisory Board (SAB) Panel to consider EPA's methods for particulate matter and ozone air quality benefit analysis. The SAB report, issued in January 2024, endorsed the current methods as "scientifically robust and appropriate for regulatory analyses". The report also offered recommendations for future improvements. These include combining estimates of mortality outcomes, shifting towards more transparent data sources, improving estimates of the cost of health injuries, improving the analysis of uncertainty, integrating labor productivity and human capital impacts of air pollution, and improving the user experience. EPA is working to improve its methods in response to these recommendations.

although some areas may experience increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years. Our comparison of air quality conditions with and without the rule suggests that for all snapshot years the final rules will result in widespread reductions in $PM_{2.5}$ concentrations.

Figure B-18 though Figure B-21 show changes in AS-MO3 in 2030, 2035, 2040, and 2045 relative to 2028 baseline conditions. Figure B-22 through Figure B-25 show changes in $PM_{2.5}$ in 2030, 2035, 2040, and 2045 relative to 2028 baseline conditions. Relative to 2028 baseline conditions, these figures indicate that ozone and $PM_{2.5}$ concentration will decline in virtually all areas of the country for both baseline and final rules scenarios in each further out snapshot year. However, some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ over time as a result of the modeled changes resulting from this rule.

4.3.2 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, 2020d), the Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA, 2019a), and the Supplement to the ISA for Particulate Matter (U.S. EPA, 2022f). These documents synthesize the toxicological, clinical, and epidemiological evidence to determine whether PM 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. Historically, the Agency estimates the incidence of air pollution effects for those health endpoints that the ISA classified as either causal or likely-to-be-causal. The analysis also accounts for recommendations from the Science Advisory Board (U.S. EPA Science Advisory Board, 2019, 2020a). When updating each health endpoint 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. The Health Benefits TSD (U.S. EPA, 2023b) fully describes 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[116].

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, 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 4-4 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 4.4 and Table 4-4 below report other omitted health and environmental benefits expected from the emissions and effluent changes as a result of this final rule, such as health effects associated with NO_2 and SO_2, and any welfare effects such as acidification and nutrient enrichment.

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

Consistent with economic theory, the willingness-to-pay (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 (Kivi and Shogren, 2010; U.S. EPA Science Advisory Board, 2020b). 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.[117] All else equal, this approach may underestimate the benefits of $PM_{2.5}$ and ozone 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.[118] At the same time, WTP may be lower for those health outcomes for which causality has not been definitively

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[117] This decision criterion for selecting health effects to quantify and monetize $PM_{2.5}$ and ozone 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 section 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.

[118] 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 (Health Benefits TSD section 6.2.3).

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. Table 4-4 reports the effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive. The table below omits welfare effects such as acidification and nutrient enrichment.

Table 4-4 Health Effects of Ambient Ozone and $PM_{2.5}$ and Climate Effects

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]
Climate Effects	Climate impacts from carbon dioxide (CO_2)	—	✓	Section 4.2
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA

[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.

4.3.3 Calculating Counts of Air Pollution Effects Using the Health Impact Function

We use the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in annual mean $PM_{2.5}$ and summer season average ozone concentrations for the years 2028, 2030, 2035, 2040 and 2045 using health impact functions (Sacks et al., 2020). A health impact function combines information regarding: the concentration-response relationship between air quality changes and the risk of a given adverse outcome; the population exposed to the air quality change; the baseline rate of death or disease in that population; and the air pollution concentration to which the population is exposed.

BenMAP quantifies counts of attributable effects using health impact functions, which combine 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 among adults aged 18 and older (a) in each county in the contiguous U.S. j (j=1,…,J where J is the total number of counties) as

$$y_{ij} = \Sigma_a \, y_{ija}$$

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

where mo_{ija} is the baseline total mortality rate for adults aged a=18-99 in county j in year i stratified in 10-year age groups, e is Euler’s Number, β is the risk coefficient for total 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=18-99 in county j in year i stratified into 5-year age groups.[119]

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 particulate matter and ground-level ozone; and cost of illness or willingness to pay economic unit values for each endpoint.

To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued. In other cases, such as for changes in ozone and PM, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to Künzli et al. (2000) and other, more recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer adapts primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

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[119] In this illustrative example, the air quality is resolved at the county level. For this RIA, we simulate air quality concentrations at 12 km grid resolution. The BenMAP-CE tool assigns the rates of baseline death and disease stored at the county level to the grid cell level using an area-weighted algorithm. This approach is described in greater detail in the appendices to the BenMAP-CE user manual.

4.3.4 Calculating the Economic Valuation of Health Impacts

After quantifying the change in adverse health impacts, the final step is to estimate the economic value of these avoided impacts. The appropriate economic value for a change in a health effect depends on whether the health effect is viewed ex ante (before the effect has occurred) or ex post (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. The appropriate economic measure is therefore ex ante WTP for changes in risk. However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use these data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a regulation reduces the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $1000, then the WTP for an avoided statistical premature mortality amounts to $10 million ($1000/0.0001 change in risk). Hence, this value is population-normalized, as it accounts for the size of the population and the percentage of that population experiencing the risk. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we instead use the cost of treating or mitigating the effect to economically value the health impact. For example, for the valuation of hospital admissions, we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These cost-of-illness (COI) estimates generally (although not in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect.

This analysis uses several recent improvements in health endpoint valuation relative to the methods described in the Health Benefits TSD (U.S. EPA, 2023b). School loss days now account for lost human capital formation, as was discussed in the Health Benefits TSD which was reviewed by the EPA Scientific Advisory Board's Review of BenMAP and Benefits

Methods. We include new estimates of the cost asthma onset and stroke beyond those described in the Health Benefits TSD.

The new valuation estimate for school loss days is described in the Health Benefits TSD in Section 5.3.8. We include two costs of school loss days: caregiver costs and loss of learning. We calculate each separately and then sum. Caregiver costs are valued at their employers' average cost for employed caregivers. For unemployed caregivers, the opportunity cost of their time is calculated as the average take-home pay. The loss of learning is calculated based on the impact of absences on learning multiplied by the impact of school learning on adult earnings. The loss of learning estimate is currently only available for middle and high school students. The two costs are summed.

The caregiver costs assumes that an adult caregiver stays home with the child and loses any wage income they would have earned that day. For working caregivers, we follow EPA guidance and value their time at the average wage including fringe benefits and overhead costs. The average daily wage in 2021 was $195 (2015 dollars, assumed to be the average weekly wage divided by 5),[120] which yields an average daily labor cost of $340 for employed parents after applying average multipliers of 1.46 for fringe benefits and 1.2 for overhead. For nonworking caregivers, we assume that the opportunity cost of time is the average after-tax earnings. We estimate the income tax rate for a median household to be 7 percent, yielding net earnings of $195 multiplied by 0.93 or $181 (2015 dollars). The income tax rate of 7 percent is the percentage difference in median post-tax income and median income from Tables A1 and C1 in Shrider et al. (2021).

The probability that a parent is working is measured with the employment population ratio among people with their own children under 18 and is 77.2 percent.[121] Combining the cost of working and nonworking caregivers yields a caregiver cost of $305 per school loss day.

To measure the loss of learning, we update the Liu et al. (2021) estimate. Liu et al. (2021) estimated the impact of a school absence on learnings as measured by an end-of-course test score. We multiply by an estimate of the impact of learning as measured by end-of-course test

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[120] U.S. Bureau of Labor Statistics (2022), series Employment, Hours, and Earnings from the Current Employment Statistics (Series ID CES0500000011).

[121] U.S. Bureau of Labor Statistics Employment Characteristics of Families, 2021, Table 5.

scores on adult income from Chetty et al. (2014). This approach yields an estimated learning loss of $2,842 per school absence (discounted at 2 percent), $2,230 per school absence (discounted at 3 percent) and $975 per school absence (discounted at 7 percent).

We updated the Chetty et al. (2014) estimate to use 2010 income and to estimate lifetime incomes discounted at 3 percent and 7 percent. Liu et al. (2021) estimate that a school absence leads to a $1,200 reduction in lifetime earnings, based on the Chetty et al. (2014) estimate that lifetime earnings are $522,000 (2010 dollars). We use 2010 ACS data from IPUMS to calculate expected lifetime earnings of $1,137,732 (discounting at 2 percent), $892,579 (discounting at 3 percent) and $390,393 (discounting at 7 percent). We then multiply the Liu et al. (2021) estimate of $1,200 by ($1,137,732 divided by $522,000) and ($892,579 divided by $522,000) and ($390,393 divided by $522,000) and convert from 2010 dollars to 2015 dollars based on the Consumer Price Index for All Urban Consumers.

We use caregiver costs for preschool and elementary school children and the sum of caregiver costs and loss of learning for middle school and high school students. We calculate that 31 percent of children under 18 are middle school and high school ages 13-18, assuming each bin is distributed equally, so the combined average effect is $1,186 ($305 plus $2,842 multiplied by 0.31) with 2 percent discounting, $1,000 ($305 plus $2,230 multiplied by 0.31) with 3 percent discounting, and $610 ($305 plus $975 multiplied by 0.31) with 7 percent discounting in 2015 dollars (U.S. Census Bureau, 2010).[122]

We include a new estimate of the cost of illness of asthma onset based on Fann and Maniloff (2023) since that described in the Health Benefits TSD (U.S. EPA, 2023b). These estimates are $181,249 with a 2 percent discount rate, $146,370 with a 3 percent discount rate, and $76,629 in 2015$. We include a new estimate of the cost of illness of stroke onset based on Fann and Maniloff (2023). These estimates are $158,763 with a 2 percent discount rate, $150,675 with a 3 percent discount rate, and $123,984 in 2015$.

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[122] U.S. Census Bureau, Age and Sex Composition in the United States: 2010, Table 1, https://www.census.gov/data/tables/2010/demo/age-and-sex/2010-age-sex-composition.html

4.3.5 *Benefits Analysis Data Inputs*

In Figure 4-1, we summarize the key data inputs to the health impact and economic valuation estimates using $PM_{2.5}$ inputs as an example, which were calculated using BenMAP-CE model version 1.5.1 (Sacks et al., 2020). In the sections below we summarize the data sources for each of these inputs, including demographic projections, incidence and prevalence rates, effect coefficients, and economic valuation.

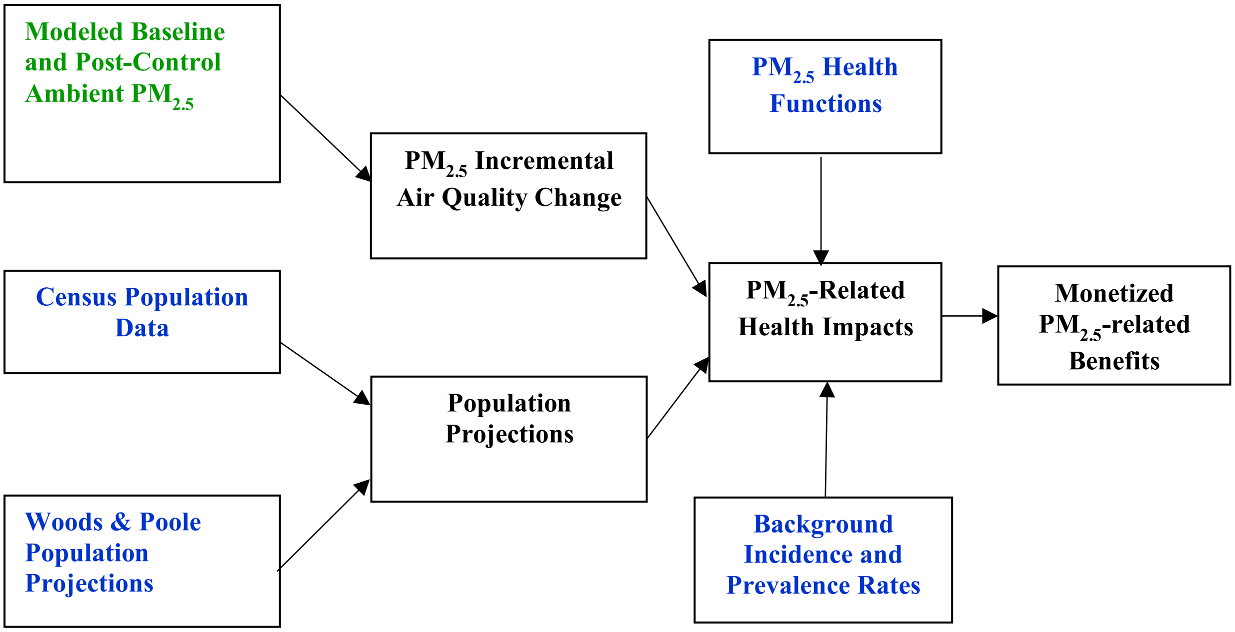

Figure 4-1 Data Inputs and Outputs for the BenMAP-CE Model Using $PM_{2.5}$ as an Example

4.3.5.1 *Demographic Data*

Quantified and monetized human health impacts depend on the demographic characteristics of the population, including age, location, and income. We use projections based on economic forecasting models developed by Woods & Poole, Inc. (2015). The Woods & Poole database contains county-level projections of population by age, sex, and race to 2060, relative to a baseline using the 2010 Census data. Projections in each county are determined simultaneously with every other county in the U.S. to consider patterns of economic growth and migration. The sum of growth in county-level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollmann et al., 2000).

According to Woods & Poole, linking county-level growth projections together and constraining the projected population to a national-level total growth avoids potential errors introduced by forecasting each county independently (for example, the projected sum of county-level populations cannot exceed the national total). County projections are developed in a four-stage process:

- First, national-level variables such as income, employment, and populations are forecasted.
- Second, employment projections are made for 179 economic areas defined by the Bureau of Economic Analysis (U.S. BEA, 2004), using an "export-base" approach, which relies on linking industrial-sector production of non-locally consumed production items, such as outputs from mining, agriculture, and manufacturing with the national economy. The export-based approach requires estimation of demand equations or calculation of historical growth rates for output and employment by sector.
- Third, population is projected for each economic area based on net migration rates derived from employment opportunities and following a cohort-component method based on fertility and mortality in each area.
- Fourth, employment and population projections are repeated for counties, using the economic region totals as bounds. The age, sex, and race distributions for each region or county are determined by aging the population by single year by sex and race for each year through 2060 based on historical rates of mortality, fertility, and migration.

4.3.5.2 Baseline Incidence and Prevalence Estimates

Epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than estimating the absolute number of avoided cases. For example, a typical result might be that a 5 $\mu g/m^3$ decrease in daily $PM_{2.5}$ levels is associated with a decrease in hospital admissions of 3 percent. A baseline incidence rate, necessary to convert this relative change into a number of cases, is the estimate of the number of cases of the health effect per year in the assessment location, as it corresponds to baseline pollutant levels in that location. To derive the total baseline incidence per year, this rate must be multiplied by the corresponding population number. For example, if the baseline incidence rate is the number of cases per year per million people, that number must be multiplied by the millions of people in the total population.

The Health Benefits TSD (U.S. EPA, 2023b) (Table 12) summarizes the sources of baseline incidence rates and reports average incidence rates for the endpoints included in the analysis. For both baseline incidence and prevalence data, we used age-specific rates where available. We applied concentration-response functions to individual age groups and then summed over the relevant age range to provide an estimate of total population benefits. National-level incidence rates were used for most morbidity endpoints, whereas county-level data are available for premature mortality. Whenever possible, the national rates used are national averages, because these data are most applicable to a national assessment of benefits. For some studies, however, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level.

We projected mortality rates such that future mortality rates are consistent with our projections of population growth (U.S. EPA, 2023b). To perform this calculation, we began first with an average of 2007-2016 cause-specific mortality rates. Using Census Bureau projected national-level annual mortality rates stratified by age range, we projected these mortality rates to 2060 in 5-year increments (U.S. Census Bureau). Further information regarding this procedure may be found in the Health Benefits TSD and the appendices to the BenMAP user manual (U.S. EPA, 2022a, 2023b).

The baseline incidence rates for hospital admissions and emergency department visits reflect the revised rates first applied in the Revised Cross-State Air Pollution Rule Update (U.S. EPA, 2021). In addition, we revised the baseline incidence rates for acute myocardial infarction. These revised rates are more recent than the rates they replace and more accurately represent the rates at which populations of different ages, and in different locations, visit the hospital and emergency department for air pollution-related illnesses (AHRQ, 2016). Lastly, these rates reflect unscheduled hospital admissions only, which represents a conservative assumption that most air pollution-related visits are likely to be unscheduled. If air pollution-related hospital admissions are scheduled, this assumption would underestimate these benefits.

4.3.5.3 Effect Coefficients

Our approach for selecting and parametrizing effect coefficients for the benefits analysis is described fully in the Health Benefits TSD. Because of the substantial economic value associated with estimated counts of $PM_{2.5}$-attributable deaths, we describe our rationale for selecting among long-term exposure epidemiologic studies below; a detailed description of all remaining endpoints may be found in the Health Benefits TSD.

A substantial body of published scientific literature documents the association between $PM_{2.5}$ concentrations and the risk of premature death (U.S. EPA, 2019a, 2022f). This body of literature reflects thousands of epidemiology, toxicology, and clinical studies. The PM ISA, completed as part of this review of the PM standards and reviewed by the Clean Air Scientific Advisory Committee (CASAC) (U.S. EPA Science Advisory Board, 2022) concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the full body of scientific evidence (U.S. EPA, 2019a, 2022f). The size of the mortality effect estimates from epidemiologic studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make mortality risk reduction the most significant health endpoint quantified in this analysis.

EPA selects hazard ratios from cohort studies to estimate counts of PM-related premature death, following a systematic approach detailed in the Health Benefits TSD accompanying this RIA that is generally consistent with previous RIAs (e.g., (U.S. EPA, 2019b, 2020a, 2020b, 2021, 2022c)). Briefly, clinically significant epidemiologic studies of health endpoints for which ISAs report strong evidence are evaluated using established minimum and preferred criteria for identifying studies and hazard ratios best characterizing risk. Further discussion of the cohort studies and hazard ratios for quantifying ozone- and $PM_{2.5}$-attributable premature death can be found below in Sections 4.3.6 and 4.3.7.

4.3.6 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 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 Health Benefits 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 (National Research Council, 2008) issued a series of recommendations to 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" (National Research Council, 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis of total mortality (Bell et al., 2004), two multi-city studies of cardiopulmonary and total mortality (Huang et al., 2005; 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 (R. L. 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.S. EPA, 2020d).

EPA quantifies and monetizes effects the Integrated Science Assessment (ISA) identifies as having either a causal or likely-to-be-causal relationship with the pollutant. Relative to the 2015 ISA, the 2020 ISA for Ozone reclassified the casual relationship between short-term ozone exposure and total mortality, changing it from "likely to be causal" to "suggestive of, but not sufficient to infer, a causal relationship." The 2020 Ozone ISA separately classified short-term

O_3 exposure and respiratory outcomes as being "causal" and long-term exposure as being "likely to be causal." When determining whether there existed a causal relationship between short- or long-term ozone exposure and respiratory effects, EPA evaluated the evidence for both morbidity and mortality effects. The ISA identified evidence in the epidemiologic literature of an association between ozone exposure and respiratory mortality, finding that the evidence was not entirely consistent and there remained uncertainties in the evidence base.

EPA continues to quantify premature respiratory mortality attributable to both short- and long-term exposure to ozone because doing so is consistent with: (1) the evaluation of causality noted above; and (2) EPA's approach for selecting and quantifying endpoints described in the Technical Support Document (TSD) "Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits," which was recently reviewed by the U.S. EPA Science Advisory Board (U.S. EPA, 2023b; U.S. EPA Science Advisory Board, 2024).

Beginning with the RCU analysis we use two estimates of ozone-attributable respiratory deaths from short-term exposures estimated using the risk estimate parameters from Zanobetti and Schwartz (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 and Schwartz (2008) as June-August. Instead, we apply this risk estimate to our standard warm season of April-September.(R. L. Smith et al., 2009; Zanobetti and Schwartz, 2008) and one long-term cohort study of respiratory mortality (Jerrett et al., 2009).

Table 11 in the Health Benefits TSD lists the ozone risk estimates used in benefits analysis.

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

The PM ISA, which was reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (SAB-CASAC), 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 (U.S. EPA, 2022e; U.S. EPA Science Advisory Board, 2019, 2022). 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, 2009a) (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, 2010, 2011a, 2011b, 2012, 2015a, 2015b, 2015c, 2016b).

Following this systematic approach led to the identification of three studies best characterizing the risk of premature death associated with long-term exposure to $PM_{2.5}$ in the U.S. (Pope et al., 2019; Turner et al., 2016; Wu et al., 2020). The PM ISA, Supplement to the ISA, and 2022 Policy Assessment also identified these three studies as providing key evidence of the association between long-term $PM_{2.5}$ exposure and mortality (U.S. EPA, 2019a, 2022b, 2022f). These studies used data from three U.S. cohorts: (1) an analysis of Medicare beneficiaries (Medicare); (2) the American Cancer Society (ACS); and (3) the National Health Interview Survey (NHIS). As premature mortality typically constitutes the vast majority of monetized benefits in a $PM_{2.5}$ benefits assessment, quantifying effects using risk estimates reported from multiple long-term exposure studies using different cohorts helps account for uncertainty in the estimated number of PM-related premature deaths. Below we summarize the three identified studies and hazard ratios and then describe our rationale for quantifying premature PM-attributable deaths using two of these studies.

Wu et al. (2020) evaluated the relationship between long-term $PM_{2.5}$ exposure and all-cause mortality in more than 68.5 million Medicare enrollees (over the age of 64), using Medicare claims data from 2000-2016 representing over 573 million person-years of follow up and over 27 million deaths. This cohort included over 20 percent of the U.S. population and was, at the time of publishing, the largest air pollution study cohort to date. The authors modeled $PM_{2.5}$ exposure at a 12 km grid resolution using a hybrid ensemble-based prediction model that combined three machine learning models and relied on satellite data, land-use information, weather variables, chemical transport model simulation outputs, and monitor data. Wu et al., 2020 fit five different statistical models: a Cox proportional hazards model, a Poisson regression model, and three causal inference approaches (GPS estimation, GPS matching, and GPS weighting). All five statistical approaches provided consistent results; we report the results of the

Cox proportional hazards model here. The authors adjusted for numerous individual-level and community-level confounders, and sensitivity analyses suggest that the results are robust to unmeasured confounding bias. In a single-pollutant model, the coefficient and standard error for $PM_{2.5}$ are estimated from the hazard ratio (1.066) and 95 percent confidence interval (1.058-1.074) associated with a change in annual mean $PM_{2.5}$ exposure of 10.0 $\mu g/m^3$ (Wu et al., 2020, Table S3, Main analysis, 2000-2016 Cohort, Cox PH). We use a risk estimate from this study in place of the risk estimate from Di et al. (2017). These two epidemiologic studies share many attributes, including the Medicare cohort and statistical model used to characterize population exposure to $PM_{2.5}$. As compared to Di et al. (2017), Wu et al. (2020) includes a longer follow-up period and reflects more recent $PM_{2.5}$ concentrations.

Pope et al. (2019) examined the relationship between long-term $PM_{2.5}$ exposure and all-cause mortality in a cohort of 1,599,329 U.S. adults (aged 18-84 years) who were interviewed in the National Health Interview Surveys (NHIS) between 1986 and 2014 and linked to the National Death Index (NDI) through 2015. The authors also constructed a sub-cohort of 635,539 adults from the full cohort for whom body mass index (BMI) and smoking status data were available. The authors employed a hybrid modeling technique to estimate annual-average $PM_{2.5}$ concentrations derived from regulatory monitoring data and constructed in a universal kriging framework using geographic variables including land use, population, and satellite estimates. Pope et al. (2019) assigned annual-average $PM_{2.5}$ exposure from 1999-2015 to each individual by census tract and used complex (accounting for NHIS's sample design) and simple Cox proportional hazards models for the full cohort and the sub-cohort. We select the Hazard Ratio calculated using the complex model for the sub-cohort, which controls for individual-level covariates including age, sex, race-ethnicity, inflation-adjusted income, education level, marital status, rural versus urban, region, survey year, BMI, and smoking status. In a single-pollutant model, the coefficient and standard error for $PM_{2.5}$ are estimated from the hazard ratio (1.12) and 95 percent confidence interval (1.08-1.15) associated with a change in annual mean $PM_{2.5}$ exposure of 10.0 $\mu g/m^3$ (Pope et al., 2019) (Table 2, Subcohort). This study exhibits two key strengths that makes it particularly well suited for a benefits analysis: (1) it includes a long follow-up period with recent (and thus relatively low) $PM_{2.5}$ concentrations; (2) the NHIS cohort is representative of the U.S. population, especially with respect to the distribution of individuals by race, ethnicity, income, and education.

EPA has historically used estimated Hazard Ratios from extended analyses of the ACS cohort (Krewski et al., 2009; Pope et al., 2002; Pope et al., 1995) to estimate PM-related risk of premature death. More recent ACS analyses (Pope et al., 2015; Turner et al., 2016):

- extended the follow-up period of the ACS CSP-II to 22 years (1982-2004),
- evaluated 669,046 participants over 12,662,562 person-years of follow up and 237,201 observed deaths, and
- applied a more advanced exposure estimation approach than had previously been used when analyzing the ACS cohort, combining the geostatistical Bayesian Maximum Entropy framework with national-level land use regression models.

The total mortality hazard ratio best estimating risk from these ACS cohort studies was based on a random-effects Cox proportional hazard model incorporating multiple individual and ecological covariates (relative risk =1.06, 95 percent confidence intervals 1.04–1.08 per 10µg/m^3 increase in $PM_{2.5}$) from Turner et al., 2016. The relative risk estimate is identical to a risk estimate drawn from earlier ACS analysis of all-cause long-term exposure $PM_{2.5}$-attributable mortality (Krewski et al., 2009). However, as the ACS hazard ratio is quite similar to the Medicare estimate of (1.066, 1.058-1.074), especially when considering the broader age range (>29 vs >64), only the Wu et al. (2020) and Pope et al. (2019) are included in the main benefits assessments, with Wu et al. (2020) representing results from both the Medicare and ACS cohorts.

Table 10 in the Health Benefits TSD lists the $PM_{2.5}$ risk estimates used in benefits analysis.

4.3.8 Characterizing Uncertainty in the Estimated Benefits

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. The Health Benefits TSD details our approach to characterizing uncertainty in both quantitative and qualitative terms (U.S. EPA, 2023b). That Health Benefits TSD describes the sources of uncertainty associated with key input parameters including emissions inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the country (i.e., regulations, technology, and human behavior). Each of these inputs is uncertain and affects the size and distribution of the estimated benefits. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits.

To characterize uncertainty and variability into this assessment, we incorporate three quantitative analyses described below and in greater detail within the Health Benefits TSD (Section 7.1):

1. A Monte Carlo assessment that accounts for random sampling error and between study variability in the epidemiological and economic valuation studies;

2. The quantification of PM-related mortality using alternative $PM_{2.5}$ mortality effect estimates drawn from two long-term cohort studies; and

3. Presentation of 95th percentile confidence interval around each risk estimate.

Quantitative characterization of other sources of $PM_{2.5}$ uncertainties are discussed only in Section 7.1 of the Health Benefits TSD:

1. For adult all-cause mortality:

    a. The distributions of air quality concentrations experienced by the original cohort population (Health Benefits TSD Section 7.1.2.1);

    b. Methods of estimating and assigning exposures in epidemiologic studies (Health Benefits TSD Section 7.1.2.2);

    c. Confounding by ozone (Health Benefits TSD Section 7.1.2.3); and

    d. The statistical technique used to generate hazard ratios in the epidemiologic study (Health Benefits TSD Section 7.1.2.4).

2. Plausible alternative risk estimates for asthma onset in children (Health Benefits TSD Section 7.1.3), cardiovascular hospital admissions (Health Benefits TSD Section 7.1.4,), and respiratory hospital admissions (Health Benefits TSD Section 7.1.5);

3. Effect modification of $PM_{2.5}$-attributable health effects in at-risk populations (Health Benefits TSD Section 7.1.6).

Quantitative consideration of baseline incidence rates and economic valuation estimates are provided in Section 7.3 and 7.4 of the TSD, respectively. Qualitative discussions of various sources of uncertainty can be found in Section 7.5 of the TSD.

4.3.8.1 Monte Carlo Assessment

Similar to recent RIAs that monetize $PM_{2.5}$ and ozone-related health benefits, we used Monte Carlo methods for characterizing random sampling error associated with the concentration response functions from epidemiological studies and random effects modeling to characterize both sampling error and variability across the economic valuation functions. The Monte Carlo simulation in the BenMAP-CE software randomly samples from a distribution of incidence and valuation estimates to characterize the effects of uncertainty on output variables. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and monetized benefits. The reported standard errors in the epidemiological studies determined the distributions for individual effect estimates for endpoints estimated using a single study. For endpoints estimated using a pooled estimate of multiple studies, the confidence intervals reflect both the standard errors and the variance across studies. The confidence intervals around the monetized benefits incorporate the epidemiology standard errors as well as the distribution of the valuation function. These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

4.3.8.2 Sources of Uncertainty Treated Qualitatively

Although we strive to incorporate as many quantitative assessments of uncertainty as possible, there are several aspects we are only able to address qualitatively. These attributes are summarized below and described more fully in the Health Benefits TSD.

Key assumptions underlying the estimates for premature mortality, which account for over 98 percent of the total monetized benefits in this analysis, include the following:

1. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$

varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The PM ISA, which was reviewed by CASAC, concluded that "across exposure durations and health effects categories … the evidence does not indicate that any one source or component is consistently more strongly related with health effects than $PM_{2.5}$ mass" (U.S. EPA, 2019a).

2. We assume that the health impact function for fine particles is log-linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with the particulate matter NAAQS and those that do not meet the standard down to the lowest modeled concentrations. The PM ISA concluded that "the majority of evidence continues to indicate a linear, no-threshold concentration-response relationship for long-term exposure to $PM_{2.5}$ and total (nonaccidental) mortality" (U.S. EPA, 2019a). The Supplement to the 2019 Integrated Science Assessment for Particulate Matter continues to support a no-threshold concentration-response relationship.[123]

3. 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 Science Advisory Board, 2004), which affects the valuation of mortality benefits at different discount rates. Similarly, we assume there is a cessation lag between the change in PM exposures and both the development and diagnosis of lung cancer.

4. Uncertainties associated with the IPM projections used to derive the inputs for the air quality modeling in this analysis are outlined in Section 3.8. IPM is a system-wide least-cost optimization model that projects EGU behavior across the geographically contiguous U.S., and projects one possible combination of compliance outcomes under a given policy scenario. The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs

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[123] https://assessments.epa.gov/isa/document/&deid=354490

comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA.

5. Uncertainties associated with applying air quality modeling to create ozone and $PM_{2.5}$ surfaces are discussed in Appendix B.

4.3.9 Estimated Number and Economic Value of Health Benefits

Table 4-5 through Table 4-14 report the estimated number of reduced premature deaths and illnesses in each year relative to the baseline along with the 95 percent confidence interval. Table 4-5 through report the ozone-related health benefits for each scenario and year, and Table 4-10 through Table 4-14 report the PM-related health benefits for each scenario and year. The number of reduced estimated deaths and illnesses from the three illustrative scenarios are calculated from the sum of individual reduced mortality and illness risk across the population.

Table 4-15 through Table 4-19 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. Table 4-20 summarizes the monetized benefits for all illustrative scenarios and the five analysis years. We also report the stream of benefits from 2028 through 2047 for the final rules and alternatives, using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts (Table 4-15 through Table 4-19).[124] When estimating the value of improved air quality over a multi-year time horizon, the analysis applies population growth and income growth projections for each future year through 2047 and estimates of baseline mortality incidence rates at five-year increments.

Table 4-21 through Table 4-23 include two estimates for each scenario at a 2, 3, and 7 percent discount rate. These estimates were quantified using two different epidemiological estimates for the mortality impact of ozone and two different epidemiological estimates for the mortality impact of PM, as well as their sum. For ozone, one estimate reflects the impacts associated with short-term exposure on mortality impacts while the other reflects long-term exposure on mortality. For PM, one estimate reflects impacts associated mortality estimated based on Pope et al. (2019), while the other reflects impacts associated with mortality estimated

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[124] 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.

based on Wu et al. (2020). These estimates should not be thought of as representing low and high bounds.

As shown in Tables 4-21 through 4-23, the present value of the monetized human health benefits from 2028 through 2047 is as high as \$120 billion (2 percent discount rate) and the equivalent annualized values (EAVs) are \$6.3 billion at a 2 percent discount rate. Although there are disbenefits for ozone in 2040 and a mix of benefits and disbenefits for $PM_{2.5}$ in 2040, we expect that most locations with disbenefits from the final rules will still show positive benefits when accounting for impacts on ozone and $PM_{2.5}$ concentrations over the entire period that health benefits are analyzed (i.e., 2028 to 2047).

Table 4-5 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios for 2028 (95 percent confidence interval)[a]

		Final Rules	Alternative 1	Alternative 2
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	60 (42 to 78)	56 (39 to 73)	54 (37 to 69)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	2.7 (1.1 to 4.3)	2.5 (1.0 to 4.0)	2.4 (0.98 to 3.8)
Morbidity effects				
Long-term exposure	Asthma onset[d]	510 (430 to 580)	450 (390 to 510)	430 (370 to 490)
	Allergic rhinitis symptoms[f]	2,900 (1,500 to 4,200)	2,600 (1,400 to 3,800)	2,500 (1,300 to 3,600)
Short-term exposure	Hospital admissions—respiratory[c]	7.9 (-2.1 to 17)	7.3 (-1.9 to 16)	6.6 (-1.7 to 15)
	ED visits—respiratory[e]	160 (45 to 340)	150 (41 to 310)	140 (40 to 300)
	Asthma symptoms	93,000 (-12,000 to 190,000)	84,000 (-10,000 to 170,000)	80,000 (-9,900 to 170,000)
	Minor restricted-activity days[c,e]	41,000 (16,000 to 64,000)	36,000 (15,000 to 57,000)	35,000 (14,000 to 55,000)
	School absence days	33,000 (-4,600 to 69,000)	29,000 (-4,200 to 62,000)	28,000 (-4,000 to 59,000)

[a] Values rounded to two significant figures.

[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 4-6 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios for 2030 (95 percent confidence interval)[a]

		Final Rules	Alternative 1	Alternative 2
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	60 (42 to 78)	58 (41 to 76)	47 (32 to 61)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	2.7 (1.1 to 4.3)	2.6 (1.1 to 4.2)	2.1 (0.95 to 3.2)
Morbidity effects				
Long-term exposure	Asthma onset[d]	520 (440 to 590)	510 (430 to 580)	390 (330 to 440)
	Allergic rhinitis symptoms[f]	3,000 (1,600 to 4,300)	2,900 (1,500 to 4,300)	2,200 (1,200 to 3,300)
Short-term exposure	Hospital admissions—respiratory[c]	7.7 (-2.0 to 17)	7.5 (-2.0 to 17)	5.9 (-1.5 to 13)
	ED visits—respiratory[e]	160 (44 to 340)	160 (43 to 330)	130 (35 to 270)
	Asthma symptoms	97,000 (-12,000 to 200,000)	95,000 (-12,000 to 200,000)	73,000 (-8,900 to 150,000)
	Minor restricted-activity days[c,e]	41,000 (16,000 to 65,000)	33,000 (-4,700 to 70,000)	32,000 (13,000 to 50,000)
	School absence days	34,000 (-4,800 to 71,000)	41,000 (16,000 to 64,000)	26,000 (-3,600 to 54,000)

[a] Values rounded to two significant figures.

[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 4-7 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios for 2035 (95 percent confidence interval)[a]

		Final Rules	Alternative 1	Alternative 2
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	120 (85 to 160)	140 (98 to 180)	120 (86 to 160)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	5.6 (2.2 to 8.8)	6.4 (2.6 to 10)	5.6 (2.3 to 8.9)
Morbidity effects				
Long-term exposure	Asthma onset[d]	710 (610 to 810)	850 (730 to 970)	720 (620 to 820)
	Allergic rhinitis symptoms[f]	4,200 (2,200 to 6,100)	5,000 (2,700 to 7,300)	4,300 (2,300 to 6,200)
Short-term exposure	Hospital admissions—respiratory[c]	15 (-3.9 to 33)	17 (-4.5 to 38)	15 (-4.0 to 34)
	ED visits—respiratory[e]	250 (70 to 540)	300 (81 to 620)	260 (70 to 540)
	Asthma symptoms	130,000 (-16,000 to 280,000)	160,000 (-20,000 to 330,000)	140,000 (-17,000 to 280,000)
	Minor restricted-activity days[c,e]	61,000 (24,000 to 96,000)	73,000 (29,000 to 120,000)	63,000 (25,000 to 99,000)
	School absence days	48,000 (-6,800 to 100,000)	58,000 (-8,200 to 120,000)	49,000 (-7,000 to 100,000)

[a] Values rounded to two significant figures.

[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 4-8 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios for 2040 (95 percent confidence interval)[a]

		Final Rules	Alternative 1	Alternative 2
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	-7.0 (-4.9 to -9.1)	-1.1 (-0.73 to -1.4)	-8.8 (-6.1 to -11)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	-0.32 (-0.50 to -0.13)	-0.047 (-0.074 to -0.019)	-0.40 (-0.62 to -0.16)
Morbidity effects				
Long-term exposure	Asthma onset[d]	-39 (-33 to -44)	4.2 (3.7 to 4.7)	-58 (-50 to -66)
	Allergic rhinitis symptoms[f]	-240 (-120 to -350)	14 (7.8 to 21)	-350 (-180 to -500)
Short-term exposure	Hospital admissions—respiratory[c]	-1.4 (0.36 to -3.1)	-0.61 (0.16 to -1.3)	-1.6 (0.42 to -3.6)
	ED visits—respiratory[e]	-25 (-53 to -7.0)	-11 (-24 to -3.1)	-33 (-68 to -9.0)
	Asthma symptoms	-7,400 (900 to -15,000)	590 (-76 to 1,200)	-11,000 (1,300 to -23,000)
	Minor restricted-activity days[c,e]	-4,800 (-1,900 to -7,600)	-860 (-340 to -1,400)	-6,100 (-2,400 to -9,600)
	School absence days	-2,800 (390 to -5,800)	130 (-20 to 250)	-4,000 (560 to -8,400)

[a] Values rounded to two significant figures.

[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[c] Converted ozone risk estimate metric from maximum daily 1-hour average (MDA1) to maximum daily 8-hour average (MDA8).

[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[f] Converted ozone risk estimate metric from daily 24-hour average (DA24) to MDA8.

Table 4-9 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2045 (95 percent confidence interval)[a,b]

		Final Rules	Alternative 1	Alternative 2
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	130 (89 to 170)	130 (90 to 170)	130 (90 to 170)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	5.8 (2.3 to 9.2)	5.9 (2.4 to 9.2)	5.8 (2.4 to 9.2)
Morbidity effects				
Long-term exposure	Asthma onset[d]	860 (730 to 970)	860 (740 to 980)	860 (740 to 980)
	Allergic rhinitis symptoms[f]	5,000 (2,600 to 7,300)	5,000 (2,600 to 7,300)	5,000 (2,600 to 7,300)
Short-term exposure	Hospital admissions—respiratory[c]	16 (-4.3 to 37)	17 (-4.3 to 37)	17 (-4.3 to 37)
	ED visits—respiratory[e]	290 (79 to 600)	290 (80 to 610)	290 (80 to 610)
	Asthma symptoms	160,000 (-20,000 to 330,000)	160,000 (-20,000 to 330,000)	160,000 (-20,000 to 330,000)
	Minor restricted-activity days[c,e]	76,000 (30,000 to 120,000)	76,000 (30,000 to 120,000)	76,000 (30,000 to 120,000)
	School absence days	57,000 (-8,100 to 120,000)	58,000 (-8,100 to 120,000)	58,000 (-8,100 to 120,000)

[a] Values rounded to two significant figures.

[b] Applied risk estimate derived from April-September exposures to estimates of ozone across the May-September warm season.

[c] Converted ozone risk estimate metric from MDA1 to MDA8.

[d] Applied risk estimate derived from June-August exposures to estimates of ozone across the May-September warm season.

[e] Applied risk estimate derived from full year exposures to estimates of ozone across the May-September warm season.

[f] Converted ozone risk estimate metric from DA24 to MDA8.

Table 4-10 Estimated Avoided PM-Related Premature Mortalities and Illnesses for the Illustrative Scenarios in 2028 (95 percent confidence interval)

Avoided Mortality	**Final Rules**	**Alternative 1**	**Alternative 2**
(Pope et al., 2019) (adult mortality ages 18-99 years)	450 (320 to 570)	400 (290 to 510)	370 (260 to 470)
(Wu et al., 2020) (adult mortality ages 65-99 years)	210 (180 to 230)	190 (170 to 210)	170 (150 to 190)
(Woodruff et al., 2008) (infant mortality)	0.59 (-0.37 to 1.5)	0.51 (-0.32 to 1.3)	0.48 (-0.30 to 1.2)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	31 (23 to 39)	28 (20 to 35)	56 (-22 to 130)
Hospital admissions—respiratory	23 (8.2 to 38)	21 (7.2 to 33)	19 (6.5 to 30)
ED visits--cardiovascular	68 (-26 to 160)	61 (-23 to 140)	56 (-22 to 130)
ED visits—respiratory	140 (27 to 290)	120 (24 to 250)	110 (22 to 240)
Acute Myocardial Infarction	7.4 (4.3 to 10)	6.6 (3.8 to 9.2)	5.9 (3.5 to 8.3)
Cardiac arrest	3.3 (-1.4 to 7.5)	3.0 (-1.2 to 6.7)	2.7 (-1.1 to 6.2)
Hospital admissions--Alzheimer's Disease	120 (88 to 150)	100 (78 to 130)	95 (71 to 120)
Hospital admissions--Parkinson's Disease	14 (7.0 to 20)	12 (6.3 to 18)	11 (5.8 to 17)
Stroke	13 (3.4 to 22)	12 (3.0 to 20)	11 (2.8 to 18)
Lung cancer	15 (4.5 to 25)	13 (4.0 to 22)	12 (3.7 to 20)
Hay Fever/Rhinitis	3,400 (830 to 5,900)	3,000 (730 to 5,200)	2,800 (680 to 4,900)
Asthma Onset	530 (510 to 550)	470 (450 to 490)	440 (420 to 460)
Asthma symptoms – Albuterol use	100,000 (-48,000 to 240,000)	88,000 (-43,000 to 210,000)	82,000 (-40,000 to 200,000)
Lost work days	26,000 (22,000 to 29,000)	23,000 (19,000 to 26,000)	21,000 (18,000 to 24,000)
Minor restricted-activity days[d,f]	150,000 (120,000 to 180,000)	130,000 (110,000 to 160,000)	120,000 (100,000 to 150,000)

Note: Values rounded to two significant figures.

Table 4-11 Estimated Avoided PM-Related Premature Mortalities and Illnesses for the Illustrative Scenarios in 2030 (95 percent confidence interval)

Avoided Mortality	**Final Rules**	**Alternative 1**	**Alternative 2**
(Pope et al., 2019) (adult mortality ages 18-99 years)	290 (200 to 360)	250 (180 to 310)	190 (140 to 240)
(Wu et al., 2020) (adult mortality ages 65-99 years)	140 (120 to 150)	120 (100 to 130)	89 (79 to 100)
(Woodruff et al., 2008) (infant mortality)	0.36 (-0.23 to 0.93)	0.32 (-0.20 to 0.82)	0.27 (-0.17 to 0.70)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	20 (14 to 25)	17 (12 to 21)	13 (9.6 to 17)
Hospital admissions—respiratory	14 (4.9 to 23)	12 (4.3 to 20)	7.7 (3.4 to 12)
ED visits--cardiovascular	43 (-16 to 99)	37 (-14 to 86)	31 (-12 to 71)
ED visits—respiratory	85 (17 to 180)	74 (15 to 150)	65 (13 to 130)
Acute Myocardial Infarction	4.6 (2.6 to 6.4)	3.9 (2.3 to 5.5)	3.0 (1.7 to 4.2)
Cardiac arrest	2.1 (-0.86 to 4.8)	1.8 (-0.74 to 4.1)	1.5 (-0.60 to 3.3)
Hospital admissions--Alzheimer's Disease	75 (56 to 94)	65 (49 to 81)	46 (34 to 57)
Hospital admissions--Parkinson's Disease	9.0 (4.6 to 13)	7.8 (3.9 to 11)	5.7 (2.9 to 8.4)
Stroke	8.4 (2.2 to 14)	7.2 (1.9 to 12)	5.7 (1.5 to 9.7)
Lung cancer	9.5 (2.9 to 16)	8.2 (2.5 to 14)	6.5 (2.0 to 11)
Hay Fever/Rhinitis	2,200 (530 to 3,800)	1,900 (470 to 3,400)	1,600 (390 to 2,800)
Asthma Onset	340 (330 to 360)	300 (290 to 310)	250 (240 to 260)
Asthma symptoms – Albuterol use	64,000 (-31,000 to 160,000)	57,000 (-28,000 to 140,000)	47,000 (-23,000 to 110,000)
Lost work days	16,000 (13,000 to 18,000)	14,000 (12,000 to 16,000)	12,000 (9,800 to 13,000)
Minor restricted-activity days[d,f]	94,000 (76,000 to 110,000)	82,000 (67,000 to 97,000)	69,000 (56,000 to 81,000)

Note: Values rounded to two significant figures.

Table 4-12 Estimated Avoided PM-Related Premature Mortalities and Illnesses for the Illustrative Scenarios in 2035 (95 percent confidence interval)

Avoided Mortality	**Final Rules**	**Alternative 1**	**Alternative 2**
(Pope et al., 2019) (adult mortality ages 18-99 years)	1,100 (820 to 1,400)	1,200 (840 to 1,500)	1,200 (840 to 1,500)
(Wu et al., 2020) (adult mortality ages 65-99 years)	560 (490 to 620)	580 (510 to 640)	580 (510 to 650)
(Woodruff et al., 2008) (infant mortality)	1.2 (-0.73 to 3.0)	1.2 (-0.75 to 3.1)	1.2 (-0.75 to 3.1)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	81 (59 to 100)	84 (61 to 110)	84 (61 to 110)
Hospital admissions—respiratory	40 (17 to 62)	55 (19 to 89)	55 (19 to 90)
ED visits--cardiovascular	170 (-64 to 390)	170 (-66 to 400)	170 (-66 to 400)
ED visits—respiratory	310 (62 to 650)	320 (63 to 670)	320 (63 to 670)
Acute Myocardial Infarction	19 (11 to 26)	19 (11 to 27)	19 (11 to 27)
Cardiac arrest	8.0 (-3.3 to 18)	8.3 (-3.4 to 19)	8.3 (-3.4 to 19)
Hospital admissions--Alzheimer’s Disease	320 (240 to 390)	320 (240 to 400)	330 (240 to 410)
Hospital admissions--Parkinson’s Disease	36 (18 to 53)	37 (19 to 55)	37 (19 to 55)
Stroke	33 (8.5 to 56)	34 (8.7 to 58)	34 (8.8 to 58)
Lung cancer	38 (12 to 64)	40 (12 to 66)	40 (12 to 66)
Hay Fever/Rhinitis	7,700 (1,900 to 13,000)	8,000 (1,900 to 14,000)	8,000 (1,900 to 14,000)
Asthma Onset	1,200 (1,100 to 1,200)	1,200 (1,200 to 1,300)	1,200 (1,200 to 1,300)
Asthma symptoms – Albuterol use	230,000 (-110,000 to 550,000)	240,000 (-110,000 to 570,000)	240,000 (-110,000 to 570,000)
Lost work days	57,000 (48,000 to 66,000)	60,000 (50,000 to 69,000)	60,000 (50,000 to 69,000)
Minor restricted-activity days[d,f]	340,000 (270,000 to 400,000)	350,000 (280,000 to 420,000)	350,000 (280,000 to 420,000)

Note: Values rounded to two significant figures.

Table 4-13 Estimated Avoided PM-Related Premature Mortalities and Illnesses for the Illustrative Scenarios in 2040 (95 percent confidence interval)

Avoided Mortality	**Final Rules**	**Alternative 1**	**Alternative 2**
(Pope et al., 2019) (adult mortality ages 18-99 years)	-22 (-16 to -28)	0.92 (0.66 to 1.2)	17 (13 to 22)
(Wu et al., 2020) (adult mortality ages 65-99 years)	-11 (-9.2 to -12)	0.92 (0.81 to 1.0)	9.5 (8.3 to 11)
(Woodruff et al., 2008) (infant mortality)	-0.023 (0.015 to -0.060)	-0.0039 (0.0025 to -0.010)	0.0057 (-0.0036 to 0.015)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	-2.1 (-1.6 to -2.7)	-0.37 (-0.27 to -0.47)	0.80 (0.58 to 1.0)
Hospital admissions—respiratory	-1.6 (-0.56 to -2.6)	-0.50 (-0.19 to -0.79)	0.15 (0.019 to 0.27)
ED visits--cardiovascular	-4.0 (1.5 to -9.3)	-0.61 (0.23 to -1.4)	1.2 (-0.48 to 2.9)
ED visits—respiratory	-5.9 (-12 to -1.2)	0.36 (0.071 to 0.75)	3.0 (0.60 to 6.3)
Acute Myocardial Infarction	-0.60 (-0.35 to -0.84)	-0.21 (-0.12 to -0.29)	0.065 (0.038 to 0.092)
Cardiac arrest	-0.13 (-0.30 to 0.053)	0.039 (-0.016 to 0.086)	0.14 (-0.058 to 0.32)
Hospital admissions--Alzheimer’s Disease	-14 (-10 to -18)	-7.8 (-5.8 to -9.7)	-2.2 (-1.6 to -2.8)
Hospital admissions--Parkinson’s Disease	-0.56 (-0.29 to -0.83)	0.18 (0.090 to 0.26)	0.77 (0.39 to 1.1)
Stroke	-0.53 (-0.14 to -0.90)	0.15 (0.038 to 0.25)	0.59 (0.15 to 1.0)
Lung cancer	-0.62 (-0.19 to -1.0)	0.22 (0.066 to 0.36)	0.77 (0.24 to 1.3)
Hay Fever/Rhinitis	-78 (-19 to -140)	79 (19 to 140)	160 (39 to 280)
Asthma Onset	-11 (-11 to -12)	13 (12 to 13)	25 (24 to 26)
Asthma symptoms – Albuterol use	-2,400 (1,100 to -5,700)	2,300 (-1,100 to 5,500)	4,700 (-2,300 to 11,000)
Lost work days	-870 (-740 to -1,000)	360 (310 to 420)	990 (840 to 1,100)
Minor restricted-activity days[d,f]	-5,200 (-4,200 to -6,100)	2,100 (1,700 to 2,500)	5,900 (4,800 to 7,000)

Note: Values rounded to two significant figures.

Table 4-14 Estimated Avoided PM-Related Premature Mortalities and Illnesses for the Illustrative Scenarios in 2045 (95 percent confidence interval)

Avoided Mortality	**Final Rules**	**Alternative 1**	**Alternative 22**
(Pope et al., 2019) (adult mortality ages 18-99 years)	530 (380 to 670)	530 (380 to 680)	530 (380 to 680)
(Wu et al., 2020) (adult mortality ages 65-99 years)	270 (240 to 300)	270 (240 to 300)	270 (240 to 300)
(Woodruff et al., 2008) (infant mortality)	0.47 (-0.30 to 1.2)	0.47 (-0.30 to 1.2)	0.47 (-0.30 to 1.2)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	39 (28 to 49)	39 (28 to 49)	39 (28 to 49)
Hospital admissions—respiratory	24 (8.0 to 39)	24 (8.0 to 39)	24 (8.0 to 39)
ED visits--cardiovascular	78 (-30 to 180)	79 (-30 to 180)	79 (-30 to 180)
ED visits—respiratory	150 (29 to 300)	150 (29 to 310)	150 (29 to 300)
Acute Myocardial Infarction	8.7 (5.0 to 12)	8.8 (5.1 to 12)	8.7 (5.1 to 12)
Cardiac arrest	3.7 (-1.5 to 8.4)	3.7 (-1.5 to 8.5)	3.7 (-1.5 to 8.4)
Hospital admissions--Alzheimer's Disease	150 (110 to 190)	150 (110 to 190)	150 (110 to 190)
Hospital admissions--Parkinson's Disease	16 (8.2 to 24)	16 (8.3 to 24)	16 (8.3 to 24)
Stroke	15 (3.8 to 25)	15 (3.9 to 26)	15 (3.9 to 26)
Lung cancer	19 (5.7 to 31)	19 (5.7 to 31)	19 (5.7 to 31)
Hay Fever/Rhinitis	3,500 (840 to 6,000)	3,500 (840 to 6,100)	3,500 (840 to 6,000)
Asthma Onset	530 (510 to 550)	540 (510 to 560)	530 (510 to 550)
Asthma symptoms – Albuterol use	100,000 (-49,000 to 250,000)	100,000 (-50,000 to 250,000)	100,000 (-50,000 to 250,000)
Lost work days	27,000 (23,000 to 31,000)	27,000 (23,000 to 31,000)	27,000 (23,000 to 31,000)
Minor restricted-activity days[d,f]	160,000 (130,000 to 190,000)	160,000 (130,000 to 190,000)	160,000 (130,000 to 190,000)

Note: Values rounded to two significant figures.

Table 4-15 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2028 (95 percent confidence interval; billions of 2019 dollars)[a,d]

Disc. Rate	Pollutant	Ozone Benefits			PM Benefits			Ozone plus PM Benefits		
2%	Final Rules	$0.19	*and*	$0.81	$2.4	*and*	$5.0	$2.6[b]	*and*	$5.8[c]
	Alternative 1	$0.17	*and*	$0.75	$2.2	*and*	$4.4	$2.3[b]	*and*	$5.2[c]
	Alternative 2	$0.16	*and*	$0.71	$2.0	*and*	$4.1	$2.1[b]	*and*	$4.8[c]
3%	Final Rules	$0.18 ($0.68 to $0.32)	*and*	$0.78 ($0.12 to $1.9)	$2.3 ($0.32 to $6.0)	*and*	$4.8 ($0.54 to $13)	$2.5[b] ($0.38 to $6.3)	*and*	$5.6[c] ($0.66 to $15)
	Alternative 1	$0.16 ($0.061 to $0.29)	*and*	$0.72 ($0.11 to $1.8)	$2.1 ($0.28 to $5.4)	*and*	$4.3 ($0.48 to $11)	$2.3[b] ($0.34 to $5.7)	*and*	$5.0[c] ($0.59 to $13)
	Alternative 2	$0.15 ($0.58 to $0.28)	*and*	$0.69 ($0.11 to $1.7)	$1.9 ($0.26 to $4.9)	*and*	$4.0 ($0.44 to $11)	$2.1[b] ($0.32 to $5.2)	*and*	$4.7[c] ($0.55 to $12)
7%	Final Rules	$0.13 ($0.036 to $0.24)	*and*	$0.66 ($0.085 to $1.7)	$2.1 ($0.26 to $5.4)	*and*	$4.3 ($0.46 to $12)	$2.2[b] ($0.29 to $5.6)	*and*	$5.0[c] ($0.54 to $13)
	Alternative 1	$0.11 ($0.033 to $0.22)	*and*	$0.61 ($0.078 to $1.6)	$1.9 ($0.23 to $4.8)	*and*	$3.9 ($0.41 to $10)	$2.0[b] ($0.26 to $5.0)	*and*	$4.5[c] ($0.49 to $12)
	Alternative 2	$0.11 ($0.031 to $0.21)	*and*	$0.59 ($0.075 to $1.5)	$1.7 ($0.21 to $4.4)	*and*	$3.5 ($0.37 to $9.5)	$1.8[b] ($0.24 to $4.6)	*and*	$4.1[c] ($0.45 to $11)

[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] 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.

[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

[d] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

Table 4-16 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2030 (95 percent confidence interval; billions of 2019 dollars)[a,d]

Disc. Rate	Pollutant	Ozone Benefits			PM Benefits			Ozone plus PM Benefits		
2%	Final Rules	$0.19	*and*	$0.82	$1.6	*and*	$3.2	$1.8[b]	*and*	$4.0[c]
	Alternative 1	$0.19	and	$0.79	$1.4	and	$2.8	$1.5[b]	and	$3.6[c]
	Alternative 2	$0.14	*and*	$0.63	$1.0	*and*	$2.1	$1.2[b]	*and*	$2.8[c]
3%	Final Rules	$0.18 ($0.069 to 0.33)	*and*	$0.79 ($0.12 to $2.0)	$1.5 ($0.20 to $3.9)	*and*	$3.1 ($0.35 to $8.3)	$1.7[b] ($0.27 to $4.3)	*and*	$3.9[c] ($0.47 to $10)
	Alternative 1	$0.18 ($0.068 to 0.32)	*and*	$0.77 ($0.12 to $1.9)	$1.3 ($0.18 to $3.4)	*and*	$2.7 ($0.30 to $7.1)	$1.5[b] ($0.24 to $3.7)	*and*	$3.4[c] ($0.42 to $9.0)
	Alternative 2	$0.14 ($0.052 to $0.25)	*and*	$0.61 ($0.095 to $1.5)	$1.0 ($0.14 to $2.6)	*and*	$2.1 ($0.23 to $5.5)	$1.1[b] ($0.19 to $2.8)	*and*	$2.7[c] ($0.33 to $7.1)
7%	Final Rules	$0.13 ($0.037 to 0.25)	*and*	$0.67 ($0.086 to $1.7)	$1.4 ($0.17 to $3.5)	*and*	$2.8 ($0.29 to $7.4)	$1.5[b] ($0.20 to $3.8)	*and*	$3.5[c] ($0.38 to $9.2)
	Alternative 1	$0.13 ($0.036 to $0.24)	*and*	$0.65 ($0.084 to $1.7)	$1.2 ($0.14 to $3.0)	*and*	$2.4 ($0.25 to $6.4)	$1.3[b] ($0.18 to $3.2)	*and*	$3.0[c] ($0.34 to $8.0)
	Alternative 2	$0.097 ($0.028 to $0.19)	*and*	$0.52 ($0.066 to $1.3)	$0.89 ($0.11 to $2.3)	*and*	$1.9 ($0.20 to $5.0)	$0.99[b] ($0.14 to $2.5)	*and*	$2.4[c] ($0.26 to $6.3)

[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] 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.

[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

[d] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

Table 4-17 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2035 (95 percent confidence interval; billions of 2019 dollars)[a,d]

Disc. Rate	Pollutant	Ozone Benefits			PM Benefits			Ozone plus PM Benefits		
2%	Final Rules	\$0.29	*and*	\$1.6	\$6.6	*and*	\$13	\$6.9[b]	*and*	\$15[c]
	Alternative 1	\$0.34	*and*	\$1.8	\$6.8	*and*	\$13	\$7.1[b]	*and*	\$15[c]
	Alternative 2	\$0.29	*and*	\$1.6	\$6.8	*and*	\$14	\$7.1[b]	*and*	\$15[c]
3%	Final Rules	\$0.28 (\$0.096 to 0.52)	*and*	\$1.5 (\$0.21 to \$3.9)	\$6.4 (\$0.82 to \$16)	*and*	\$13 (\$1.4 to \$34)	\$6.7[b] (\$0.91 to \$17)	*and*	\$14[c] (\$1.6 to \$38)
	Alternative 1	\$0.33 (\$0.12 to \$0.61)	*and*	\$1.8 (\$0.25 to \$4.5)	\$6.6 (\$0.84 to \$17)	*and*	\$13 (\$1.4 to \$35)	\$6.9[b] (\$0.96 to \$18)	*and*	\$15[c] (\$1.7 to \$39)
	Alternative 2	\$0.28 (\$0.098 to 0.53)	*and*	\$1.6 (\$0.21 to \$4.0)	\$6.6 (\$0.85 to \$17)	*and*	\$13 (\$1.4 to \$35)	\$6.9[b] (\$0.95 to \$18)	*and*	\$15[c] (\$1.6 to \$39)
7%	Final Rules	\$0.20 (\$0.053 to 0.41)	*and*	\$1.3 (\$0.16 to \$3.5)	\$5.7 (\$0.68 to \$15)	*and*	\$11 (\$1.2 to \$30)	\$5.9[b] (\$0.73 to \$15)	*and*	\$13[c] (\$1.3 to \$34)
	Alternative 1	\$0.24 (\$0.063 to \$0.49)	*and*	\$1.5 (\$0.18 to \$4.0)	\$5.9 (\$0.70 to \$15)	*and*	\$12 (\$1.2 to \$31)	\$6.1[b] (\$0.76 to \$16)	*and*	\$13[c] (\$1.4 to \$35)
	Alternative 2	\$0.20 (\$0.054 to \$0.42)	*and*	\$1.4 (\$0.16 to \$3.5)	\$5.9 (\$0.70 to \$15)	*and*	\$12 (\$1.2 to \$31)	\$6.1[b] (\$0.76 to \$16)	*and*	\$13[c] (\$1.4 to \$35)

[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] 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.

[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

[d] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

Table 4-18 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2040 (95 percent confidence interval; billions of 2019 dollars)[a,d]

Disc. Rate	Pollutant	Ozone Benefits			PM Benefits			Ozone plus PM Benefits		
2%	Final Rules	-$0.093	*and*	-$0.016	-$0.26	*and*	-$0.13	-$0.35^{b}	*and*	-$0.14^{c}
	Alternative 1	-$0.011	*and*	$0.00033	$0.012	*and*	$0.012	$0.00043^{b}	*and*	$0.012^{c}
	Alternative 2	-$0.12	*and*	-$0.023	$0.11	*and*	$0.21	$0.087^{b}	*and*	$0.091^{c}
3%	Final Rules	-$0.090 (-$0.23 to -$0.012)	*and*	-$0.016 (-$0.030 to -$0.0053)	-$0.25 (-$0.67 to -$0.026)	*and*	-$0.12 (-$0.32 to -$0.015)	-$0.34^{b} (-$0.90 to -$0.038)	*and*	-$0.14^{c} (-$0.35 to -$0.020)
	Alternative 1	-$0.011 (-$0.032 to $0.00027)	*and*	$0.0003 (-$.0013 to $.0013)	$0.011 ($0.0013 to $0.029)	*and*	$0.011 ($0.0012 to $0.029)	$0.00045^{b} (-$0.030 to $0.030)	*and*	$0.012^{c} (-$0.000077 to $0.030)
	Alternative 2	-$0.12 (-$0.29 to -$0.016)	*and*	-$0.022 (-$0.041 to -$0.078)	$0.11 ($0.014 to $0.29)	*and*	$0.20 ($0.022 to $0.53)	$0.085^{b} (-$0.27 to $0.52)	*and*	$0.088^{c} (-$0.027 tc $0.28)
7%	Final Rules	-$0.078 (-$0.20 to -$0.0089)	*and*	-$0.011 (-$0.024 to -$0.0029)	-$0.22 (-$0.60 to -$0.023)	*and*	-$0.11 (-$0.28 to -$0.013)	-$0.30^{b} (-$0.80 to -$0.032)	*and*	-$0.12^{c} (-$0.31 to -$0.016)
	Alternative 1	-$0.010 (-$0.029 to -$0.000089)	*and*	-$0.000078 (-$0.0016 to $0.00081)	$0.094 ($0.00051 to $0.025)	*and*	$0.0094 ($0.00049 to $0.026)	-$0.00065^{b} (-$0.028 to $0.026)	*and*	$0.0094^{c} (-$0.0011 to $0.026)
	Alternative 2	-$0.099 (-$0.26 to -$0.012)	*and*	-$0.016 (-$0.032 to -$0.0043)	$0.098 ($0.011 to $0.26)	*and*	$0.18 ($0.018 to $0.48)	$0.079^{b} (-$0.24 to $0.47)	*and*	$0.082^{c} (-$0.021 tc $0.25)

[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] 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.

[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

[d] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

Table 4-19 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2045 (95 percent confidence interval; billions of 2019 dollars)[a,d]

Disc. Rate	Pollutant	Ozone Benefits			PM Benefits			Ozone plus PM Benefits		
2%	Final Rules	$0.34	*and*	$1.8	$3.3	*and*	$6.4	$3.6[b]	*and*	$8.2[c]
	Alternative 1	$0.34	*and*	$1.8	$3.3	*and*	$6.5	$3.7[b]	*and*	$8.2[c]
	Alternative 2	$0.34	*and*	$1.8	$3.3	*and*	$6.4	$3.7[b]	*and*	$8.2[c]
3%	Final Rules	$0.33 ($0.12 to $0.60)	*and*	$1.7 ($0.24 to $4.4)	$3.2 ($0.40 to $8.3)	*and*	$6.3 ($0.67 to $17)	$3.5[b] ($0.52 to $8.9)	*and*	$7.9[c] ($0.91 to $21)
	Alternative 1	$0.33 ($0.12 to $0.61)	*and*	$1.7 ($0.24 to $4.4)	$3.2 ($0.40 to $8.4)	*and*	$6.3 ($0.67 to $17)	$3.6[b] ($0.52 to $9.0)	*and*	$8.0[c] ($0.92 to $21)
	Alternative 2	$0.33 ($0.12 to $0.61)	*and*	$1.700 ($0.24 to $4.4)	$3.2 ($0.40 to $8.3)	*and*	$6.3 ($0.67 to $17)	$3.6[b] ($0.52 to $8.9)	*and*	$8.0[c] ($0.91 to $21)
7%	Final Rules	$0.24 ($0.063 to $0.48)	*and*	$1.5 ($0.18 to $3.9)	$2.9 ($0.33 to $7.4)	*and*	$5.5 ($0.57 to $15)	$3.1[b] ($0.40 to $7.9)	*and*	$7.0[c] ($0.75 to $19)
	Alternative 1	$0.24 ($0.063 to $0.48)	*and*	$1.5 ($0.18 to $3.9)	$2.9 ($0.34 to $7.5)	*and*	$5.6 ($0.58 to $15)	$3.1[b] ($0.40 to $7.9)	*and*	$7.1[c] ($0.76 to $19)
	Alternative 2	$0.24 ($0.063 to $0.48)	*and*	$1.5 ($0.18 to $3.9)	$2.9 ($0.34 to $7.5)	*and*	$5.6 ($0.58 to $15)	$3.1[b] ($0.40 to $7.9)	*and*	$7.1[c] ($0.75 to $19)

[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] 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.

[c] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Pope et al. (2019) long-term $PM_{2.5}$ exposure mortality risk estimate.

[d] EPA is unable to provide confidence intervals for 2 percent-based estimates currently.

Table 4-20 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2028, 2030, 2035, 2040 and 2045 (billions of 2019 dollars)[a,b]

		2% Discount Rate	**3% Discount Rate**	**7% Discount Rate**
		Ozone and PM Benefits	**Ozone and PM Benefits**	**Ozone and PM Benefits**
2028	Final Rules	$5.8	$5.6	$5.0
	Alternative 1	$5.2	$5.0	$4.5
	Alternative 2	$4.8	$4.7	$4.1
2030	Final Rules	$4.0	$3.9	$3.5
	Alternative 1	$3.6	$3.4	$3.0
	Alternative 2	$2.8	$2.7	$2.4
2035	Final Rules	$15	$14	$13
	Alternative 1	$15	$15	$13
	Alternative 2	$15	$15	$13
2040	Final Rules	-$0.35	-$0.34	-$0.30
	Alternative 1	$0.00043	$0.00045	-$0.00065
	Alternative 2	$0.087	$0.085	$0.079
2045	Final Rules	$8.2	$7.9	$7.0
	Alternative 1	$8.2	$8.0	$7.1
	Alternative 2	$8.2	$8.0	$7.1

[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] Values are the monetized benefits of the mortality and illnesses included in Tables 4-5 through 4-14.

Table 4-21 Stream of Human Health Benefits from 2028 through 2047: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness and Long-Term $PM_{2.5}$ Mortality and Illness for EGUs (discounted at 2 percent; billions of 2019 dollars)[a]

	Final Rules	Alternative 1	Alternative 2
2028*	$5.8	$5.2	$4.8
2029	$5.9	$5.3	$4.9
2030*	$4.0	$3.6	$2.8
2031	$4.1	$3.6	$2.8
2032	$14	$14	$14
2033	$14	$15	$15
2034	$14	$15	$15
2035*	$15	$15	$15
2036	$15	$16	$15
2037	$15	$16	$16
2038	-$0.34	$0.0026	$0.089
2039	-$0.34	$0.0016	$0.088
2040*	-$0.35	$0.00043	$0.087
2041[b]	-$0.36	-$0.0011	$0.085
2042	$7.9	$8.0	$7.9
2043	$8.0	$8.1	$8.0
2044	$8.1	$8.1	$8.1
2045*	$8.2	$8.2	$8.2
2046	$8.3	$8.3	$8.3
2047	$8.3	$8.4	$8.4
PV	$120	$120	$120
EAV	$6.3	$6.5	$6.3

*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. 2019 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and $PM_{2.5}$ and ozone-related morbidity effects.

[a] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[b] The 2040 analysis year is applied to the years 2038-2041. As the population grows each year, the ozone disbenefits in the 2040 analysis run are applied to a larger population each year leading to declining benefits during this period.

Table 4-22 Stream of Human Health Benefits from 2028 through 2047: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness and Long-Term $PM_{2.5}$ Mortality and Illness for EGUs (discounted at 3 percent; billions of 2019 dollars)[a]

	Final Rules	Alternative 1	Alternative 2
2028*	$5.6	$5.0	$4.7
2029	$5.8	$5.2	$4.8
2030*	$3.9	$3.4	$2.7
2031	$4.0	$3.5	$2.8
2032	$13	$14	$14
2033	$14	$14	$14
2034	$14	$15	$14
2035*	$14	$15	$15
2036	$15	$15	$15
2037	$15	$15	$15
2038	-$0.33	$0.0025	$0.087
2039	-$0.33	$0.0016	$0.086
2040*	-$0.34	$0.00045	$0.085
2041[b]	-$0.35	-$0.00097	$0.083
2042	$7.7	$7.7	$7.7
2043	$7.7	$7.8	$7.8
2044	$7.8	$7.9	$7.9
2045*	$7.9	$8.0	$8.0
2046	$8.0	$8.1	$8.0
2047	$8.1	$8.1	$8.1
PV	$100	$110	$100
EAV	$6.1	$6.2	$6.1

*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. 2019 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and $PM_{2.5}$ and ozone-related morbidity effects.

[a] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[b] The 2040 analysis year is applied to the years 2038-2041. As the population grows each year, the ozone disbenefits in the 2040 analysis run are applied to a larger population each year leading to declining benefits during this period.

Table 4-23 Stream of Human Health Benefits from 2028 through 2047: Monetized Benefits Quantified as Sum of Long-Term Ozone Mortality and Illness and Long-Term $PM_{2.5}$ Mortality and Illness for EGUs (discounted at 7 percent; billions of 2019 dollars)[a]

	Final Rules	Alternative 1	Alternative 2
2028*	$5.0	$4.5	$4.1
2029	$5.1	$4.6	$4.2
2030*	$3.5	$3.0	$2.4
2031	$3.5	$3.1	$2.4
2032	$12	$12	$12
2033	$12	$13	$13
2034	$12	$13	$13
2035*	$13	$13	$13
2036	$13	$13	$13
2037	$13	$14	$14
2038	$-0.29	$0.0013	$0.081
2039	$-0.3	$0.00044	$0.08
2040*	$-0.3	$-0.00065	$0.079
2041[b]	$-0.31	$-0.0019	$0.077
2042	$6.8	$6.9	$6.8
2043	$6.9	$6.9	$6.9
2044	$6.9	$7.0	$7.0
2045	$7.0	$7.1	$7.1
2046	$7.1	$7.2	$7.1
2047	$7.2	$7.2	$7.2
PV	$59	$60	$58
EAV	$5.2	$5.2	$5.1

*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. 2019 study); Ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. 2016 study); and $PM_{2.5}$ and ozone-related morbidity effects.

[a] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[b] The 2040 analysis year is applied to the years 2038-2041. As the population grows each year, the ozone disbenefits in the 2040 analysis run are applied to a larger population each year leading to declining benefits during this period.

4.4 Additional Unquantified Benefits

Data, time, and resource limitations prevented EPA from quantifying the estimated health impacts or monetizing estimated benefits associated with incremental changes in direct exposure to NO_2 and SO_2, independent of the role NO_2 and SO_2 play as precursors to $PM_{2.5}$ and ozone, as well as ecosystem effects, and visibility impairment that might result from emissions changes associated with compliance with the final requirements. While all health benefits and welfare benefits were not quantified, it does not imply that there are not additional benefits associated with reductions in human exposures to NO_2 or SO_2 and ecosystem exposure to air pollutants potentially resulting from emissions changes under this rule. In this section, we provide a qualitative description of these and water quality benefits, which are listed in Table 4-24. Note also that some pollutants from U.S. EGUs, such as NO_2, SO_2, and particulate matter, can be transported downwind into foreign countries, in particular Canada and Mexico. Therefore, reduced pollution from U.S. EGUs can lead to public health and welfare benefits in foreign countries. EPA is currently unable to quantify or monetize these effects.

Table 4-24 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]
	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. 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]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_X SO_X ISA[1]
	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 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]

[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.

4.4.1 Hazardous Air Pollutant Impacts

4.4.1.1 Mercury Air Pollutant Impacts

The final rules are expected to reduce fossil fuel-fired EGU generation and consequentially is expected to lead to reduced HAP emissions. HAP emitted from EGUs can cause 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 have been 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.

The final rules are expected to reduce emissions of mercury. Mercury is a persistent, bioaccumulative toxic metal that is emitted from power plants in three forms: gaseous elemental mercury (Hg0), oxidized mercury compounds (Hg+2), and particle-bound mercury (HgP). Elemental mercury does not quickly deposit or chemically react in the atmosphere, resulting in residence times that are long enough to contribute to global scale deposition. Oxidized mercury and HgP deposit quickly from the atmosphere impacting local and regional areas in proximity to sources. MeHg is formed by microbial action in the top layers of sediment and soils, after mercury has precipitated from the air and deposited into waterbodies or land. Once formed, MeHg is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have MeHg concentrations many times, typically on the order of one million times, that of the concentrations in the freshwater body in which they live. MeHg can adversely impact ecosystems and wildlife. The projected reductions in mercury are expected to reduce the bioconcentration of MeHg in fish. Subsistence fishing is associated with vulnerable populations, including minorities and those of low socioeconomic status. Further reductions in mercury emissions from lignite-fired facilities could help address exposure inequities for the subsistence fisher sub-population.

Human exposure to MeHg is known to have several adverse neurodevelopmental impacts, such as IQ loss measured by performance on neurobehavioral tests, particularly on tests of attention, fine motor-function, language, and visual spatial ability. In addition, evidence in humans and animals suggests that MeHg can have adverse effects on both the developing and the adult cardiovascular system, including fatal and non-fatal ischemic heart disease (IHD). Further, nephrotoxicity, immunotoxicity, reproductive effects (impaired fertility), and developmental effects have been observed with MeHg exposure in animal studies disease (ATSDR, 2022). MeHg has some genotoxic activity and is capable of causing chromosomal damage in a number of experimental systems. EPA has classified MeHg as a “possible” human carcinogen.

4.4.1.2 Metal HAP

The projected reductions in emissions of non-mercury metal HAP are expected to reduce exposure to carcinogens, such as nickel, arsenic, and hexavalent chromium, in the surrounding areas. U.S. EGUs are the largest source of selenium (Se) emissions and a major source of metallic HAP emissions including arsenic (As), chromium (Cr), nickel (Ni), and cobalt (Co). Additionally, U.S. EGUs emit cadmium (Cd), beryllium (Be), lead (Pb), and manganese (Mn). These emissions include metal HAPs that are persistent and bioaccumulative (Cd, As, and Pb) and others have the potential to cause cancer (Ni, Cr, Cd, Be, Co, and Pb). PM controls are expected to reduce metal HAP emissions and therefore reduce the potential for adverse effects from metal HAP exposure.

Exposure to these metal HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes; decreased pulmonary function, pneumonia, or lung damage; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). As of 2023, three of the key metal HAP emitted by EGUs (As, Cr, and Ni) have been classified as human carcinogens, while two others (Cd, and Se) are classified as probable human carcinogens.

4.4.2 NO_2 Health Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NO_X emissions are also linked to a variety of adverse health effects associated with direct exposure. This analysis only quantifies and monetizes the ozone $PM_{2.5}$ benefits associated with the reductions in NO_X emissions and does not quantify the impacts of changing direct exposure to NO_2. Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment for Oxides of Nitrogen —Health Criteria (NO_X ISA) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2 (U.S. EPA, 2016a). 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 NO_X 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 NO_X 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.

4.4.3 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. This analysis only quantifies and monetizes the $PM_{2.5}$ benefits associated with the reductions in SO_2 emissions and does not quantify the impacts of changing direct exposure to SO_2. 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) 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 pre-existing 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.

4.4.4 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, 2020d). 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 *Ozone Transport Policy Analysis Proposed Rule TSD* (U.S. EPA, 2022g) for a summary of an assessment of risk of ozone-related growth impacts on selected forest tree species.

4.4.5 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 (NO_X/SO_X/PM ISA), NO_X and SO_2 emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment (U.S. EPA, 2020c). 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, 2008).

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In 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, 2008).

4.4.6 Visibility Impairment Benefits

Reducing ambient $PM_{2.5}$ levels would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2009b). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996).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, 2009b). Previous analyses show that visibility benefits can be a significant welfare benefit category. In this analysis we did not quantify visibility-related benefits and did not determine whether the emission reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas (U.S. EPA, 2012).

Reductions in emissions of direct $PM_{2.5}$, SO_2, and NO_2 will improve the level of visibility throughout the United States because primary and secondary $PM_{2.5}$ impairs visibility by scattering and absorbing light (U.S. EPA, 2009b). 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, 2009b). 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, 2009b).

4.4.7 Water Quality and Availability Benefits

As described in Section 3, operators are expected to increase generation from lower-emitting resources in the baseline, and these final rules are expected to continue this trend. Operators may increase generation at some subset of fossil fuel units, particularly those that install CCS. As described in Section 3, incremental adoption of CCS and hydrogen technologies are expected under this rulemaking, and as noted in preamble sections VII(F)(3), X(D)(1), and

XIV(E)(3), these technologies have water demands and may have implications for water availability.

At coal units that decrease generation, there are several negative health, ecological, and productivity effects associated with water effluent and intake that will be avoided. The impacts of coal generation on water quality and availability are qualitatively described below. For additional discussion of these impacts and welfare implications, see U.S. EPA (2020b) and U.S. EPA (2023a). Coal units that increase generation, particularly those that install CCS, may have associated water quality disbenefits if there is increased effluent related to wet-flue gas desulfurization (FGD) controls and bottom ash (BA) transport. However, this concern would be mitigated with the finalization of the 2023 *Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, which proposes zero-discharge effluent limitations for FGD wastewater and BA transport water.[125] Also, the proposed effluent limitation guidelines propose new numeric limits to combustion residual leachate, which addresses concerns that FGD waste increases leachate of mercury.

4.4.7.1 Potential Water Quality Benefits of Reduced Coal-Fired Power Generation

Discharges of wastewater from coal-fired power plants 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 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 (i.e., exceeding drinking water Maximum Contaminant Levels (MCLs)) 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

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[125] https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2023-proposed-rule

Residual wastes, with benefits in the form of avoided cleanup and other costs associated with impoundment releases.

Discharges of wastewater from coal-fired power plants affect 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, corresponding surface water quality changes can affect the ecological condition and recreation use effects. EPA expects the ecological impacts from reduced 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.

4.4.7.2 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 can significantly increase the cost of public water supply.

Although public drinking water supplies are subject to legally enforceable maximum contaminant levels (MCLs), established by EPA, pollutants discharged from coal-fired power plants, particularly episodic releases, may not be removed adequately during treatment at a drinking water treatment plant exposing consumers 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.

4.4.7.3 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 U.S. EPA (2020b) and U.S. EPA (2023a) 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.

4.4.7.4 Changes in Surface Water Quality

Reduced 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.

4.4.7.5 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.

4.4.7.6 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).

4.4.7.7 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 (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. 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. (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 (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. 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. (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 (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. 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. (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 (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. 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.

4.4.7.8 Changes in Water Withdrawals

A reduction in water withdrawals 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. Reductions in water withdrawals will also lower the number of aquatic organisms impinged and entrained by the power plant's water filtration and cooling systems.

4.5 Total Benefits

Table 4-25 through Table 4-28 present the combined monetized climate benefits[126] and $PM_{2.5}$ and ozone-related health benefits for the three illustrative scenarios for the five snapshot years analyzed. Table 4-30 through Table 4-32 present the stream of annual monetized combined climate benefits and $PM_{2.5}$ and ozone-related health benefits for the three illustrative scenarios, as well as the present values (PVs) and equivalent annualized values (EAVs), calculated for the 2024 to 2047 timeframe.

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[126] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with EPA's updated estimates of the SC-CO_2. OMB has long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. Because the SC-CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-CO_2. See Section 4.2 for more discussion.

Table 4-25 Total Benefits for the Illustrative Scenarios for 2028 (billions of 2019 dollars)[a]

			Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits)		
	SC-CO_2 Near-term Ramsey Discount Rate	Climate Benefits Only	2%	3%	7%
Final Rules					
	1.5%	14	20	20	19
	2.0%	8.4	14	14	13
	2.5%	5.2	11	11	10
Alternative 1					
	1.5%	13	19	18	18
	2.0%	7.9	13	13	12
	2.5%	4.9	10	10	9.4
Alternative 2					
	1.5%	12	17	17	16
	2.0%	7.1	12	12	11
	2.5%	4.4	9.2	9.1	8.5
Non-Monetized Benefits[c]					
Benefits from reductions in HAP emissions					
Benefits from improved water quality and availability					
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP					
Reductions in exposure to ambient NO_2 and SO_2					
Improved visibility (reduced haze) from $PM_{2.5}$ reductions					

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[c] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-26 Total Benefits for the Illustrative Scenarios for 2030 (billions of 2019 dollars)[a]

			Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits)		
	$SC\text{-}CO_2$ Near-term Ramsey Discount Rate	Climate Benefits Only	2%	3%	7%
Final Rules					
	1.5%	19	23	23	22
	2.0%	11	15	15	15
	2.5%	7.1	11	11	11
Alternative 1					
	1.5%	18	22	22	21
	2.0%	11	14	14	14
	2.5%	6.8	10	10	9.9
Alternative 2					
	1.5%	10	13	13	13
	2.0%	6.2	9.0	8.9	8.6
	2.5%	3.9	6.7	6.6	6.3
Non-Monetized Benefits[c]					
Benefits from reductions in HAP emissions					
Benefits from improved water quality and availability					
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP					
Reductions in exposure to ambient NO_2 and SO_2					
Improved visibility (reduced haze) from $PM_{2.5}$ reductions					

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[c] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CO_2$ and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-27 Total Benefits for the Illustrative Scenarios for 2035 (billions of 2019 dollars)[a]

			Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits)		
	$SC\text{-}CO_2$ Near-term Ramsey Discount Rate	**Climate Benefits Only**	**2%**	**3%**	**7%**
Final Rules					
	1.5%	50	64	64	62
	2.0%	30	45	44	43
	2.5%	19	34	33	32
Alternative 1					
	1.5%	50	65	65	63
	2.0%	30	46	45	43
	2.5%	19	35	34	32
Alternative 2					
	1.5%	49	64	64	62
	2.0%	30	45	44	43
	2.5%	19	34	34	32
Non-Monetized Benefits[c]					
Benefits from reductions in HAP emissions					
Benefits from improved water quality and availability					
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP					
Reductions in exposure to ambient NO_2 and SO_2					
Improved visibility (reduced haze) from $PM_{2.5}$ reductions					

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[c] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CO_2$ and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-28 Total Benefits for the Illustrative Scenarios for 2040 (billions of 2019 dollars)[a]

			Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits)		
	$SC\text{-}CO_2$ Near-term Ramsey Discount Rate	**Climate Benefits Only**	**2%**	**3%**	**7%**
Final Rules					
	1.5%	23	22	22	22
	2.0%	14	14	14	14
	2.5%	9.1	8.8	8.8	8.8
Alternative 1					
	1.5%	23	23	23	23
	2.0%	14	14	14	14
	2.5%	9.1	9.1	9.1	9.1
Alternative 2					
	1.5%	23	23	23	23
	2.0%	14	14	14	14
	2.5%	9.0	9.1	9.1	9.1
Non-Monetized Benefits[c]					
Benefits from reductions in HAP emissions					
Benefits from improved water quality and availability					
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP					
Reductions in exposure to ambient NO_2 and SO_2					
Improved visibility (reduced haze) from $PM_{2.5}$ reductions					

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[c] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CO_2$ and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-29 Total Benefits for the Illustrative Scenarios for 2045 (billions of 2019 dollars)[a]

			Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits)		
	$SC\text{-}CO_2$ Near-term Ramsey Discount Rate	**Climate Benefits Only**	**2%**	**3%**	**7%**
Final Rules					
	1.5%	19	27	27	26
	2.0%	12	20	20	19
	2.5%	7.8	16	16	15
Alternative 1					
	1.5%	18	26	26	25
	2.0%	11	20	19	18
	2.5%	7.5	16	15	15
Alternative 2					
	1.5%	18	26	26	25
	2.0%	11	20	19	18
	2.5%	7.5	16	15	15
Non-Monetized Benefits[c]					
Benefits from reductions in HAP emissions					
Benefits from improved water quality and availability					
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP					
Reductions in exposure to ambient NO_2 and SO_2					
Improved visibility (reduced haze) from $PM_{2.5}$ reductions					

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[c] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the $SC\text{-}CO_2$ and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-30 Benefits for the Final Rules Illustrative Scenario from 2024 through 2047 (billions of 2019 dollars)[a]

	All Values Calculated using 2% Discount Rate			Health Benefits Calculated using 3% Discount Rate, Climate Benefits Calculated using 2% Discount Rate			Health Benefits Calculated using 7% Discount Rate, Climate Benefits Calculated using 2% Discount Rate		
	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits
2028	8.4	5.8	14	8.4	5.6	14	8.4	5.0	13
2029	8.5	5.9	14	8.5	5.8	14	8.5	5.1	14
2030	11	4.0	15	11	3.9	15	11	3.5	15
2031	12	4.1	16	12	4.0	16	12	3.5	15
2032	29	14	43	29	13	42	29	12	41
2033	29	14	43	29	14	43	29	12	42
2034	30	14	44	30	14	44	30	12	42
2035	30	15	45	30	14	44	30	13	43
2036	31	15	46	31	15	45	31	13	44
2037	31	15	46	31	15	46	31	13	44
2038	14	-0.34	13	14	-0.33	13	14	-0.29	13
2039	14	-0.34	14	14	-0.33	14	14	-0.30	14
2040	14	-0.35	14	14	-0.34	14	14	-0.30	14
2041	14	-0.36	14	14	-0.35	14	14	-0.31	14
2042	11	7.9	19	11	7.7	19	11	6.8	18
2043	12	8.0	20	12	7.7	19	12	6.9	18
2044	12	8.1	20	12	7.8	20	12	6.9	19
2045	12	8.2	20	12	7.9	20	12	7.0	19
2046	12	8.3	20	12	8.0	20	12	7.1	19
2047	12	8.3	21	12	8.1	20	12	7.2	19
PV[d]	**270**	**120**	**390**	**270**	**100**	**370**	**270**	**59**	**330**
EAV[d]	**14**	**6.3**	**21**	**14**	**6.1**	**20**	**14**	**5.2**	**19**

Non-Monetized Benefits[e]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from $PM_{2.5}$ reductions

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[a] Emissions impacts are not estimated for the years 2024 to 2027. As a result, the first year of benefits analysis is 2028.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[d] The PV and EAV values in this table are for the timeframe of 2024 to 2047, not 2028 to 2047.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-31 Benefits for the Alternative 1 Illustrative Scenario from 2028 through 2047 (billions of 2019 dollars)[a,b]

	All Values Calculated using 2% Discount Rate			Health Benefits Calculated using 3% Discount Rate, Climate Benefits Calculated using 2% Discount Rate			Health Benefits Calculated using 7% Discount Rate, Climate Benefits Calculated using 2% Discount Rate		
	Climate Benefits	**$PM_{2.5}$ and O_3-related Health Benefits**[c]	**Total Benefits**	**Climate Benefits**	**$PM_{2.5}$ and O_3-related Health Benefits**[c]	**Total Benefits**	**Climate Benefits**	**$PM_{2.5}$ and O_3-related Health Benefits**[c]	**Total Benefits**
2028	7.9	5.2	13	7.9	5.0	13	7.9	4.5	12
2029	8.0	5.3	13	8.0	5.2	13	8.0	4.6	13
2030	11	3.6	14	11	3.4	14	11	3.0	14
2031	11	3.6	15	11	3.5	15	11	3.1	14
2032	29	14	43	29	14	43	29	12	41
2033	29	15	44	29	14	44	29	13	42
2034	30	15	45	30	15	44	30	13	43
2035	30	15	46	30	15	45	30	13	43
2036	31	16	46	31	15	46	31	13	44
2037	31	16	47	31	15	47	31	14	45
2038	14	0.0026	14	14	0.0025	14	14	0.0013	14
2039	14	0.0016	14	14	0.0016	14	14	0.00044	14
2040	14	0.00043	14	14	0.00045	14	14	-0.00065	14
2041	14	-0.0011	14	14	-0.00097	14	14	-0.0019	14
2042	11	8.0	19	11	7.7	19	11	6.9	18
2043	11	8.1	19	11	7.8	19	11	6.9	18
2044	11	8.1	19	11	7.9	19	11	7.0	18
2045	11	8.2	20	11	8.0	19	11	7.1	18
2046	12	8.3	20	12	8.1	20	12	7.2	19
2047	12	8.4	20	12	8.1	20	12	7.2	19
PV[d]	**270**	**120**	**390**	**270**	**110**	**370**	**270**	**60**	**330**
EAV[d]	**14**	**6.5**	**21**	**14**	**6.2**	**20**	**14**	**5.2**	**19**

Non-Monetized Benefits[e]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from $PM_{2.5}$ reductions

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[a] Emissions impacts are not estimated for the years 2024 to 2027. As a result, the first year of benefits analysis is 2028.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.

[d] The PV and EAV values in this table are for the timeframe of 2024 to 2047, not 2028 to 2047.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 4-32 Benefits for the Alternative 2 Illustrative Scenario from 2024 through 2047 (billions of 2019 dollars)[a]

	All Values Calculated using 2% Discount Rate			Health Benefits Calculated using 3% Discount Rate, Climate Benefits Calculated using 2% Discount Rate			Health Benefits Calculated using 7% Discount Rate, Climate Benefits Calculated using 2% Discount Rate		
	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits[c]	Total Benefits
2028	7.1	4.8	12	7.1	4.7	12	7.1	4.1	11
2029	7.2	4.9	12	7.2	4.8	12	7.2	4.2	11
2030	6.2	2.8	9.0	6.2	2.7	8.9	6.2	2.4	8.6
2031	6.3	2.8	9.2	6.3	2.8	9.1	6.3	2.4	8.8
2032	28	14	43	28	14	42	28	12	41
2033	29	15	43	29	14	43	29	13	41
2034	29	15	44	29	14	44	29	13	42
2035	30	15	45	30	15	44	30	13	43
2036	30	15	46	30	15	45	30	13	44
2037	31	16	46	31	15	46	31	14	44
2038	14	0.089	14	14	0.087	14	14	0.081	14
2039	14	0.088	14	14	0.086	14	14	0.080	14
2040	14	0.087	14	14	0.085	14	14	0.079	14
2041	14	0.085	14	14	0.083	14	14	0.077	14
2042	11	7.9	19	11	7.7	19	11	6.8	18
2043	11	8.0	19	11	7.8	19	11	6.9	18
2044	11	8.1	19	11	7.9	19	11	7.0	18
2045	11	8.2	20	11	8.0	19	11	7.1	18
2046	12	8.3	20	12	8.0	20	12	7.1	19
2047	12	8.4	20	12	8.1	20	12	7.2	19
PV[d]	**250**	**120**	**370**	**250**	**100**	**360**	**250**	**58**	**310**
EAV[d]	**13**	**6.3**	**20**	**13**	**6.1**	**20**	**13**	**5.1**	**19**
Non-Monetized Benefits[e]									
Benefits from reductions in HAP emissions									
Benefits from improved water quality and availability									
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP									
Reductions in exposure to ambient NO_2 and SO_2									
Improved visibility (reduced haze) from $PM_{2.5}$ reductions									

[a] Emissions impacts are not estimated for the years 2024 to 2027. As a result, the first year of benefits analysis is 2028.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[c] For simplicity of presentation, the estimated value of the health benefits reported here are the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates. For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8.
[d] The PV and EAV values in this table are for the timeframe of 2024 to 2047, not 2028 to 2047.
[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

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5 SOCIAL COSTS AND ECONOMIC IMPACTS

This section discusses potential energy market impacts, economy-wide social costs and economic impacts, small entity impacts, and labor impacts associated with these final rules. The social cost and economy-wide impacts are estimated using EPA's SAGE model. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. For additional discussion of impacts on fuel use and electricity prices, see Section 3.

5.1 Energy Market Impacts

The energy sector impacts presented in Section 3 of this RIA include potential changes in the prices for electricity, natural gas, and coal resulting from the requirements of the final rules. This section addresses the impact of these potential changes on other markets and discusses some of the determinants of the magnitude of these potential impacts. We refer to these changes as secondary market impacts.

Under the final emission guidelines for existing fossil-fuel fired steam generating units, coal-fired EGUs are not directly required to use any of the measures that EPA determines constitute BSER. Rather, CAA section 111(d) allows each state in applying standards of performance based on the BSER candidate technologies to take into account remaining useful life and other factors. Given the flexibility afforded states in implementing the emission guidelines under 111(d) and the flexibilities coal-fired EGUs have in complying with the subsequent, state-established emission standards, the potential economic impacts of the illustrative scenarios reported in this RIA are necessarily illustrative of actions that states and affected EGUs may take. The implementation approaches adopted by the states, and the strategies adopted by affected EGUs, will ultimately drive the magnitude and timing of secondary impacts from changes in the price of electricity and the demand for inputs by the electricity sector on other markets that use and produce these inputs.

To estimate the energy market impacts of the rules, EPA modeled an illustrative final rules scenario using IPM, as described in Section 1 and Section 3. This section provides a quantitative assessment of the energy price impacts for the illustrative final rules scenario and qualitative assessment of the factors that will in part determine the timing and magnitude of potential effects in other markets. Table 5-1 summarizes projected changes in energy prices and fuel use resulting from the illustrative final scenario.

Table 5-1 Summary of Certain Energy Market Impacts (percent change)

		2028	**2030**	**2035**	**2040**	**2045**
Retail electricity prices (2019 mills/kWh)	Baseline	110	113	109	108	105
	Final Rules	109	112	110	108	105
	Percentage Change (%)	-0.7%	-0.5%	1.4%	0.2%	0.7%
Average price of coal delivered to the power sector (2019$/ton)	Baseline	1.7	1.8	1.8	1.8	1.6
	Final Rules	1.7	1.7	1.7	1.8	1.1
	Percentage Change (%)	-1.4%	-1.1%	-0.5%	0.5%	-31.6%
Coal production for power sector use (million tons)	Baseline	250	218	141	90	26
	Final Rules	236	209	112	104	4
	Percentage Change (%)	-6%	-4%	-21%	15%	-4%
Price of natural gas delivered to power sector (2019$/MMBtu)	Baseline	3.2	3.3	3.3	3.2	3.3
	Final Rules	3.2	3.3	3.4	3.2	3.3
	Percentage Change (%)	-1.5%	-0.5%	3.0%	0.0%	0.1%
Price of average Henry Hub (spot) (2019$/MMBtu)	Baseline	3.1	3.3	3.3	3.2	3.3
	Final Rules	3.1	3.3	3.3	3.2	3.3
	Percentage Change (%)	-1.6%	-0.6%	2.9%	-0.1%	0.0%
Natural gas use for electricity generation (Trillion Cubic Feet)	Baseline	12	12	9	6	4
	Final Rules	11	12	10	6	4
	Percentage Change (%)	-1.0%	-1.7%	4.4%	0.0%	1.8%

Note: Positive values indicate increases relative to the baseline.

To provide some historical context to Table 5-1, we present below recent trends observed over the last decade (2012 to 2022) for the energy market impacts listed:[127]

- The annual percent change in real electricity price over this period has been from -2.4 percent to 4 percent and averaged -0.3 percent.
- The percent change to the real annual price of coal for electricity generation has ranged from -7.2 percent to 11.4 percent over the past decade and averaged -2.3 percent.
- The percent change to annual coal use for electricity plants has ranged from -19 percent to 15 percent over the past decade and averaged -5.6 percent.
- The percent change to the real annual average cost of natural gas for electricity generation has ranged from -36 percent to 107 percent over the past decade and averaged 7.1 percent.

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[127] EIA. Electric Power Annual 2021 and 2022, available at: https://www.eia.gov/electricity/annual/

- The percent change to annual natural gas use for electricity plants has ranged from -10.2 percent to 21.0 percent over the past decade and averaged 4.9 percent.

Overall, these projected changes are largely within the range of recent historical changes.

The projected energy market and electricity retail rate impacts of the final rules are discussed more extensively in Section 3, which also presents projections of power sector generation and capacity changes by technology and fuel type. The change in retail electricity prices reported in Chapter 3 is a national average across residential, commercial, and industrial consumers.

5.2 Economy-wide Social Costs and Economic Impacts

This section analyzes the potential economy-wide impacts of the final rules using a computable general equilibrium (CGE) model. CGE models are designed to capture substitution possibilities between production, consumption, and trade; interactions between economic sectors; and interactions between a policy shock and pre-existing market distortions, such as taxes that have altered consumption, investment, and labor decisions. As such, CGE models can provide insights into the effects of regulation that occur outside of the directly regulated sector because they are able to represent the entire economy in equilibrium in the baseline and under a regulatory or policy scenario. A CGE model can also be used to estimate the social cost of a regulation.

5.2.1 Economy-wide Modelling

In 2015, EPA formed a Science Advisory Board (SAB) panel to explore the use of general equilibrium approaches, and more specifically CGE models, to prospectively evaluate the costs, benefits, and economic impacts of environmental regulation. In its final report, the SAB recommended that the Agency enhance its regulatory analyses using CGE models "to offer a more comprehensive assessment of the benefits and costs" of regulatory actions by capturing important interactions between markets and that such efforts will be most informative when there are both significant cross-price effects and pre-existing distortions in those markets (U.S. EPA

Science Advisory Board, 2017).[128] Given the typical level of aggregation in CGE models and their focus on long run equilibria, the panel observed that CGE modeling results are complements to, rather than substitutes for, the other types of detailed analysis EPA conducts for its rulemakings. The report also noted that CGE frameworks offer valuable insights into the social costs of regulation even when estimates of the benefits of the regulation are not incorporated into the models, though it highlighted explicit treatment of benefits within a CGE framework as a long-term research priority. In addition, the panel observed that CGE models may also offer insights into the ways costs are distributed across regions, sectors, or households.

In response, EPA has invested in building capacity in this class of economy-wide modeling. A key outcome of this effort is EPA's CGE model of the U.S. economy, called SAGE. The SAGE model can provide an important complement to the analyses typically performed during regulatory development by evaluating a broader set of economic impacts and offering an economy-wide estimate of social costs.[129] Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. Model version v2.1.1 of SAGE is used in this analysis.

5.2.2 Overview of the SAGE CGE Model

SAGE is a CGE model that provides a complete, but relatively aggregated, representation of the entire U.S. economy. CGE models assume that for some discrete period of time an economy can be characterized by a set of conditions in which supply equals demand in all markets (referred to as equilibrium). When the imposition of a regulation alters conditions in one or more markets, the CGE model estimates a new set of relative prices and quantities for all markets that return the economy to a new equilibrium.[130] For example, the model estimates

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[128] CGE models provide "a fiscally disciplined, consistent and comprehensive accounting framework. They can ensure that projected behavior of firms and households in a regulated market is fully consistent with the behavior of those agents in other markets. Consistent representation of behavior, in turn, leads to connections between markets, allowing CGE models to pick up effects that spill over from one market to another" (SAB 2017).

[129] CGE models may also be able to provide additional information on the benefits of regulatory interventions, though this is a relatively new but active area of research. Note that until the benefits that accrue to society from mitigating environmental externalities can be incorporated in a CGE model, the economic welfare measure from the CGE model is incomplete and needs to be augmented with traditional benefits analysis to develop measures of net benefits.

[130] CGE models are generally focused on analyzing medium- or long-run policy effects since they characterize the new equilibrium (i.e., when supply once again equals demand in all markets). Their ability to capture the

changes in relative prices and quantities for sector outputs and household consumption of goods, services, and leisure that allow the economy to return to equilibrium after the regulatory intervention. In addition, the model estimates a new set of relative prices and demand for factors of production (e.g., labor, capital, and land) consistent with the new equilibrium, which in turn determines estimates of household income changes as a result of the regulation (Marten, 2023). In CGE models, the social cost of the regulation is estimated as the change in economic welfare in the post-regulation simulated equilibrium from the pre-regulation "baseline" equilibrium. As discussed in EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (U.S. EPA, 2014). 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.

Unlike engineering cost or partial equilibrium approaches typically used to evaluate the costs of regulations, CGE models account for how effects in directly regulated sectors interact with and affect the behavior of other sectors and consumers. Figure 5-1 uses a simplified circular flow diagram to depict how input and output markets are generally connected to each other in CGE models. Following a standard assumption in economics, the model assumes that households maximize their wellbeing, while firms maximize their profits. Households supply factors of production to firms in exchange for income (e.g., wages, profits, and interest payments). Firms use the available factors of production and materials to produce outputs that are then bought and consumed by households.

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transition path of the economy depends on the degree to which they include characteristics of the economy the restrict its ability to adjust instantaneously (e.g., rigidities in capital markets).

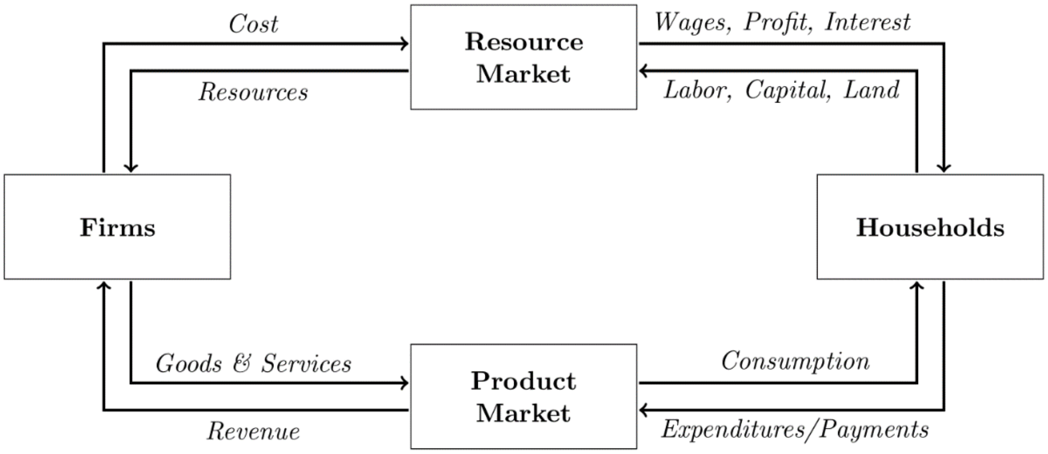

Figure 5-1 Depiction of the Circular Flow of the Economy

The SAGE model includes explicit subnational regional representation within the U.S. at the Census Region level. Each region contains representative firms for each of the 23 sectors in the model that vary by the commodity they produce and have region-specific production technologies. Each region also has five representative households that vary by income level and have region-specific preferences (see Table 5-2). Within the economy, households and firms are assumed to interact in perfectly competitive markets. In addition to households and firms, there is a single government in SAGE that represents all state, local and federal governments within the U.S. The government imposes taxes on capital earnings, labor earnings, and production and uses that revenue (in addition to deficit spending) to provide government services, make transfer payments to households, and pay interest on government debt.

Table 5-2 SAGE Dimensional Details

Time Periods	Sectors	Census Regions	Households (income)	Capital Vintage
2016-2081	Agriculture, forestry, fishing, and hunting	Northeast	<30k	Extant
(5-year time steps)	Crude oil	South	30-50k	New
	Coal mining	Midwest	50-70k	
	Metal ore and nonmetallic mineral mining	West	70-150k	
	Electric power		>150k	
	Natural gas			
	Water, sewage, and other utilities			
	Construction			
	Food and beverage manufacturing			
	Wood product manufacturing			
	Petroleum refineries			
	Chemical manufacturing			
	Plastics and rubber products manufacturing			
	Cement manufacturing			
	Primary metal manufacturing			
	Fabricated metal product manufacturing			
	Electronics and technology manufacturing			
	Transportation equipment manufacturing			
	Other manufacturing			
	Transportation			
	Truck transportation			
	Services			
	Healthcare services			

Modeling domestic and international trade presents a unique challenge in that the model's structure needs to account for the fact that the U.S. can be both an importer and an exporter of the same good at both the national and regional level. SAGE addresses this issue through use of the “Armington” approach, which assumes that imported and exported versions of the same good are not perfect substitutes. In SAGE, this assumption is applied to both international and cross-regional trade within the United States. In addition, SAGE recognizes that the U.S. is a relatively large part of the global economy and shifts in its imports and exports have the potential to influence world prices (i.e., the model assumes the United States is a large, open economy).

SAGE is a forward-looking intertemporal model, which means that households and firms are assumed to make their decisions taking into account what is expected to occur in future years and how current decisions will impact those outcomes. In an intertemporal model, care is needed to ensure that, in response to a new policy, the economy does not instantaneously jump to a new equilibrium in a way that is inconsistent with the rate at which the economy can realistically adjust. SAGE seeks to model a more realistic transition path, in part, by differentiating the flexibility of physical capital by its age. Under this approach the model distinguishes between existing capital constructed in response to previous investments and new capital constructed after the start of the model's simulation. Existing capital is assumed to be relatively inflexible and is used for its original purpose unless a relatively high cost is incurred to alter its functionality. New capital is more flexible and easily adjusts to changes in the future. Independent of its vintage, once capital has been constructed in a specific region it cannot be moved to another region. While physical capital is not mobile, households can make investments in whatever region of the country they desire.

The dynamics of the baseline economy in SAGE are informed through the calibration of key exogenous parameters in the model. Most importantly are population and productivity growth over time. The model reflects heterogeneity in productivity growth across sectors of the economy consistent with trends that have been historically observed. In addition, the model captures improvements in energy efficiency that are expected for firms and households going forward. Additional baseline characteristics, such as changes to government spending and deficits and changes to international flows of money and investments, are calibrated to key government forecasts or informed by historical trends.

The SAGE model relies on many data sources to calibrate its parameters. The foundation is a state-level dataset produced by IMPLAN that describes the interrelated flows of market goods and factors of production over the course of a year with a high level of sectoral detail.[131] This dataset is augmented by information from other sources, such as the Bureau of Economic Analysis, Energy Information Administration, Federal Reserve, Internal Revenue Service, Congressional Budget Office, and the National Bureau of Economic Research. The result is a static dataset that describes the structure and behavior of the economy in a single year.[132] These data are combined with key behavioral parameters for firms and households that are adopted

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[131] While the underlying IMPLAN data are proprietary, EPA provides the social accounting matrix based on these data in the publicly available version of SAGE. The data set for the model may also be built anew by following the instructions in the model documentation along with a licensed version of IMPLAN (www.IMPLAN.com).

[132] SAGE is solved using the General Algebraic Modeling System (GAMS) and PATH solver. The model's build stream is written in both R and GAMS.

from the published literature or econometrically estimated specifically for the purposes of calibrating SAGE. To develop the forward-looking baseline for the model, additional information on key parameters, such as productivity growth, future government spending, and energy efficiency improvements are incorporated from sources including the Congressional Budget Office and Energy Information Administration.

To ensure that SAGE is consistent with economic theory and reflects the latest science, EPA initiated a separate SAB panel to conduct a technical review of SAGE, completed in August 2020 (U.S. EPA Science Advisory Board, 2020). Peer review of SAGE was in accordance with requirements laid out for a Highly Influential Science Assessment (HISA) consistent with OMB guidelines.[133] The SAB report commended the agency on its development of SAGE, calling it a well-designed open-source model. The report included recommendations for refining and improving the model, including several changes that the SAB advised EPA to incorporate before using the model in regulatory analysis (denoted as Tier 1 recommendations by the SAB). The SAB's Tier 1 recommendations, including improving the calibration of government expenditures and deficits and the foreign trade deficit; allowing for more flexibility in the consumer demand system; and representing the United States as a large open economy, are incorporated into the model version used in this analysis (v2.1.1), as are several of the SAB's other medium- and long-run recommendations. For more details on the SAGE model, complete documentation, source code and build stream are available on EPA's website.[134]

5.2.3 Linking IPM PE Model to SAGE CGE Model

For these rules, EPA has relied on the Integrated Planning Model (IPM), a partial equilibrium large-scale unit-level linear programming model, to assess the costs of compliance in the power sector and related energy markets (see Section 3.4 for more details on the use of IPM). The SAB noted that electricity sector regulations seem a good candidate for economy-wide modeling because of the many backward and forward linkages that may result in effects in other sectors in the economy (SAB, 2017). For example, changes in the price of electricity can affect its use in the production of other goods and services. There may also be impacts to upstream

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[133] Office of Management and Budget (2004). Issuance of OMB's 'Final Information Quality Bulletin for Peer Review.' https://cfpub.epa.gov/si/m05-03.pdf

[134] https://www.epa.gov/environmental-economics/cge-modeling-regulatory-analysis

industries that supply goods and services to the electricity sector (e.g., energy commodities), labor markets in response to changes in factor prices, and household demand due to changes in the end-use price of electricity.

5.2.3.1 Compliance Costs and Social Costs

As described in Section 3, for each baseline and policy alternative, IPM solves for the least-cost approach to meet fixed electricity demands based on highly detailed information about electricity generation, air pollution control technologies, and primary energy sector market conditions (coal and natural gas) while satisfying regulatory requirements, resource adequacy, and other constraints in the electricity sector. Potential effects outside of the electricity, coal, and natural gas sectors are not evaluated within IPM. The compliance cost estimates from IPM for the finalized rules equals the estimated increase in expenditures by the power sector to achieve and maintain compliance with the final rules relative to the baseline while meeting a fixed electricity demand.

Specifically, IPM minimizes system cost, which is the sum of the total amortized payments to electricity-generating, pollution control, and transmission investments, delivered fuel costs, total variable and fixed operating and maintenance (O&M) costs, and expenditures on pollution (i.e., CO_2) transportation and storage, subject to regulatory and other constraints:[135]

system cost = amortized payments to capital + delivered fuel costs + O&M costs + expenditures on pollution transport and storage.

Note that system costs include transfers. For example, amortized payments to capital are inclusive of corporate, state, and local taxes, investment tax credits, and interest payments. Similarly, expenditures on pollution transport and storage account for 45Q tax credit payments. This allows IPM to appropriately account for transfers, including taxes and subsidies (e.g., IRA tax credits) that may target specific technologies and influence their adoption when modeling generation and investment.[136]

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[135] For further details on IPM's objective function and model formulation, see Chapter 2, and in particular Section 2.2, of the IPM documentation, available at: https://www.epa.gov/power-sector-modeling. IPM's objective function also accounts for energy and capacity payments for transmission.

[136] See Section 3 and IPM documentation for further discussion of the representation of the IRA in IPM, fuel and technology cost assumptions, and related uncertainties.

System costs can be expressed in an alternative but equivalent way as the sum of expenditures on real resources plus taxes and interest payments less subsidies received:

system cost = real resource expenditures + taxes + interest payments – subsidies.

Real resource expenditures are the expenditures on inputs required to produce electricity (e.g., labor, materials, fuel), less any transfer payments, as estimated by the IPM model:[137]

real resource expenditures = real capital expenditures + fuel expenditures + O&M expenditures + pollution transportation and storage input expenditures.

As described below, SAGE estimates the economy-wide impacts of the final rules using the estimated change in real resource expenditures by the electricity sector, which is the compliance cost estimate from IPM excluding transfers. This allows SAGE to capture the expected change in the electricity sector's demand for these real resources due to the policy. To determine the real resource expenditures, the estimates of system costs are separated into their constituent components, to the extent feasible. For example, the real capital expenditures are calculated as the amortized payment on capital excluding corporate, state, and local taxes, interest payments, and tax credits for renewables and battery storage.[138] The input expenditures for pollution transportation and storage are calculated as the expenditures on pollution transport and storage excluding 45Q payments. As described below, SAGE also uses the estimated incremental subsidy payments from IPM to capture their effect on electricity prices, which is important for modeling the output margin.[139]

The estimated compliance costs from IPM differ from the social costs of these rules for several reasons. First, the estimated compliance costs from IPM include changes beyond real resources costs, specifically transfers that should be excluded from an estimate of social costs. Second, the compliance cost estimates from IPM do not account for all relevant margins of substitution that the economy may use to respond to the final rules (e.g., electricity demand).[140]

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[137] These expressions show that expenditures on real resources projected by IPM represent the combined influence of various taxes and subsidies (as well as other market and regulatory factors identified above).

[138] The labor share of O&M costs is inclusive of taxes on labor, which are accounted for in the translation of these resource costs to SAGE to avoid double counting them.

[139] Unlike the analysis supporting the proposal for these rules, there is a de minimis expected change in the total 45V tax credit payments due to the final rules relative to the baseline.

[140] In comparing frameworks for estimating social costs, the economics literature usually compares partial to general equilibrium measures of social costs, focusing in particular on the second and third differences in this list. In

Third, the compliance cost estimates from IPM do not account for the possibility of significant cross-price effects and interactions with other pre-existing market distortions elsewhere in the economy. Fourth, the compliance costs estimates from IPM do not account for reallocation across sectors, potential reductions in aggregate investment, or the resulting effects on economic growth. By construction, SAGE explicitly allows for these possible responses and is therefore used to estimate social costs, while leveraging the insights that the detailed IPM provides on compliance behavior and costs to the power sector from these final rules.

5.2.3.2 Overview of Linking Methodology

To model the economy-wide effects of the final rules, we calibrate the SAGE model inputs that represent the impact of the final rules such that sectoral costs in a corresponding partial equilibrium sub-model of SAGE (called SAGE-PE) align with the compliance costs (excluding transfers) derived from the technology-rich IPM. This approach of aligning compliance costs between the two models allows us to avoid confounding the estimate of economy-wide effects with differences in the models' representations of sectors shared by both IPM and SAGE.[141] Care is given in translating IPM outputs for use in SAGE so that the two models adequately capture equivalent compliance costs.[142]

Figure 5-2 provides an overview of the approach leveraging the IPM results to introduce the incremental costs of the final rules into the SAGE model. In the first step (characterized as Step 0), model differences in structure and accounting are reconciled by translating IPM incremental system costs to a format consistent with the SAGE framework. This includes aligning model years, distributing IPM costs to SAGE model inputs (by fuel, other materials,

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certain cases, such as when market prices are not expected to change meaningfully, a compliance cost estimate may provide a sufficient approximation of social costs. For these rules, IPM estimates changes in prices in electricity, coal, and natural gas markets, and therefore, the compliance cost estimate may also differ meaningfully from a partial equilibrium estimate of social costs for these markets.

[141] The SAB (2017) noted that it will "often be necessary and appropriate for EPA to link a GE [general equilibrium] model having a modest degree of detail to one or more PE models having greater detail. Linked models will usually involve some degree of inconsistency in the definitions of overlapping variables and parameters, but that may be acceptable given the increased degree of detail that a linked analysis could provide."

[142] There are several valid approaches for linking models (see SAB 2017). In developing a strategy for linking IPM and SAGE, we adhere to the following criteria: it should be theoretically sensible and produce reasonable results; it should incorporate identical partial equilibrium responses across both SAGE and IPM without iteratively linking the models (since IPM is proprietary); it should be practically implementable in the development of a regulatory analysis; and the outcomes should be available to the public for the purposes of comment and transparency.

labor, and capital), attributing costs to production vintages, and removing transfer payments that may be important for IPM to capture investment behavior but inappropriate for inputs into SAGE as they would result in double counting.

The reconciled incremental costs are used to calibrate a representation of the final rules in SAGE-PE, which is a partial equilibrium representation of the electricity sector (and related primary energy sectors, such as the coal mining and natural gas) as defined from SAGE that mimics the sectoral behavior of IPM, to the degree that is possible. While SAGE-PE does not have the technology detail of IPM, it captures aggregate endogenous responses in electricity and primary energy sector prices, input requirements, trade, and asset values of existing capital resources. SAGE-PE does not include aspects of the economy represented in the full SAGE model but that are not captured in IPM. This means that market outcomes in sectors other than the electricity, coal mining and natural gas sectors, electricity demand, factor prices, and constraints on factor supply are all treated as exogenous in SAGE-PE.

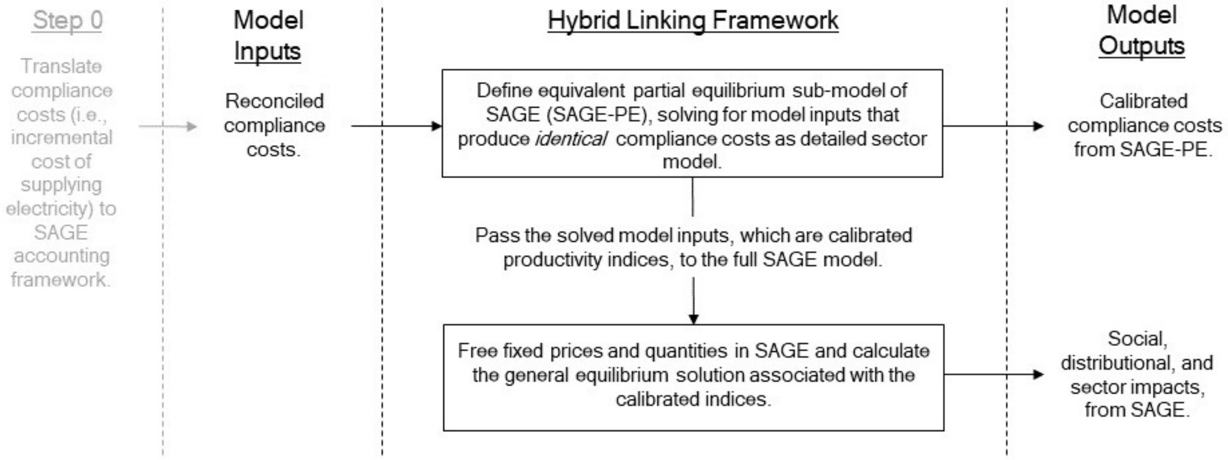

Figure 5-2 Hybrid Linkage Approach for IPM and SAGE

Because SAGE-PE is a sub-model of SAGE, most of its model equations are described in Marten et al. (2023). The subset of SAGE equations and variables that comprise SAGE-PE include conditional profit maximizing production behavior, sub-national and foreign trade, and market clearing conditions that equate supply and demand in the electricity, coal mining and natural gas sectors. As in SAGE, SAGE-PE models optimal behavior through a series of equilibrium conditions formulated as a mixed complementarity problem. Production and trade are characterized through zero profit conditions that require unit costs to be greater than or equal to unit revenues. Market clearing conditions that equate supply and demand for the electricity, coal mining and natural gas sectors determine their prices. A second set of market clearing conditions are used to determine prices in regional trade markets. SAGE-PE maintain an endogenous rental rate on extant capital to model the changes in the shadow value on existing capital stock.

A common way to represent an environmental regulation in a CGE model is through a productivity shock. This can be interpreted as requiring more inputs (e.g., control technologies) to produce the same amount of output but in compliance with the regulation. In the SAGE and SAGE-PE models, this is implemented through augmenting the reference productivity indices denominated by input (materials, fuels, labor, and capital) and is described in detail in the model documentation (Marten, 2023). The productivity shock is differentiated across model year, regions, sectors, and production vintages. In the baseline, all productivity indices are set to unity with the exception of those assigned to labor inputs which reflect projections of sector-differentiated labor productivity.[143]

To align SAGE with IPM, the productivity shock is calibrated so that the compliance costs are aligned between SAGE-PE and the IPM solution. The incremental SAGE-PE costs are defined as the difference in production costs between the policy equilibrium and the baseline. The productivity shock is adjusted to equate SAGE-PE and IPM incremental costs. Because prices for factors and non-energy inputs are not endogenously determined in SAGE-PE the incremental input costs for factors and non-energy inputs are driven through quantity demand changes for labor, new capital, and material inputs. Incremental costs for electricity, coal mining and natural gas inputs incorporate both changes in prices as well as input demand quantities. Electricity production in SAGE-PE is exogenous except for adjustments necessary to satisfy reductions or increases in electricity input demands in the electricity sector and primary energy sectors in response to the final rules. The calibrated productivity shock is then passed to the full SAGE model to generate social cost, distributional, and indirect impacts of the modeled policy,

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[143] The SAGE model was modified to allow production with extant capital to require incremental new capital for compliance (e.g., pollution control retrofits, fuel switching). This modification is implemented by defining an additional productivity index associated with new capital demands in production with extant capital.

where model years 2026 and beyond are endogenously determined. See Schreiber et al. (2023) for more details on the linking approach.

5.2.3.3 Translating IPM Outputs into SAGE Inputs

IPM produces detailed cost and emissions outputs by model plant (or aggregate representations of unit-level information of existing generators, or characterizations of new or retrofit/retire options) and wholesale electricity price impacts by IPM region. This detailed information is important for quantifying the sectoral compliance behavior attributed to a regulatory shock. However, to link IPM and SAGE to capture the broader economy-wide impacts, IPM costs need to be translated to SAGE factors and commodities. Table 5-3 summarizes the key dimensions of IPM used to calibrate the inputs for the SAGE model. Key variables include capital costs, fuel costs, and fixed and variable operations and maintenance costs. Capital costs are reported both as overnight capital costs and amortized capital payments. Overnight capital costs reflect the total value of the resources used to install a piece of capital "overnight," or without any financing costs associated with loan repayment. In reality, these expenditures are not paid immediately but rather spread out over a fixed time period with interest via amortized capital payments. The "cost" of capital in IPM is a combination of a rate of return, tax payments, and financing charges (embodied in the capital charge rate) and is used to amortize payments over the lifetime of the capital investment. Costs are further denominated by IPM region, fuel type, and generator vintage.

Table 5-3 IPM Cost Outputs

Time Periods	Cost Categories	IPM Regions	Generator Vintage
2028-2055	Overnight capital costs Amortized capital payments Fuel costs Fixed operations and maintenance costs Variable operations and maintenance costs	67 IPM Regions	Existing New

IPM incremental costs are translated into the SAGE framework by: (1) mapping IPM model years to SAGE model years;[144] (2) mapping IPM regions to SAGE regions; (3) splitting delivered fuel costs to separate transportation costs; (4) mapping variable operations and maintenance costs to specific inputs in SAGE according to the reference cost structure in the model; (5) attributing fixed operations and maintenance costs to labor; (6) attributing incremental costs on existing and new generation to production with extant and new capital, respectively;[145] and (7) removing taxes and transfers from capital payments using the difference between the capital charge rate and the capital recovery factor to recover the real resource costs. Unlike at proposal, the IPM analysis for the final rules projects very little incremental hydrogen demand, so EPA did not need to make assumptions about hydrogen input requirements for modeling it in SAGE.

Aligning the SAGE model with IPM is complicated by the difference in how each model accounts for capital payments. First, taxes and transfers (e.g., finance payments) need to be removed from capital costs to recover the real resource requirements for inputs to SAGE. Second, differences in representation of capital between the two models needs to be reconciled; SAGE accounts for capital as a cumulatively depreciated asset that represents the aggregate physical capital stock in the U.S., whereas IPM defines capital more specifically with heterogeneous terms and costs by technology. The models can be aligned by either targeting incremental overnight capital costs (e.g., the magnitude and timing of the resource change) or through targeting amortized capital payments. Because the accounting for capital is different between models, the former approach can lead to significant differences in capital payments between models. Therefore, the second approach is used to align incremental amortized payments to capital that exclude tax payments when calibrating the productivity shock. Because the representation of capital is different between the models, differences in induced investment in

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[144] IPM year 2028 is mapped to SAGE model year 2026. Subsequent IPM years (2030-2055) are mapped to the SAGE model year that is one year later (2031-2056). Because SAGE has a longer time horizon than IPM (to 2081), IPM incremental costs in 2055 are expected to continue into the future and are mapped to SAGE model years 2061-2081.

[145] Production with extant and new capital is not equivalent to differentiating existing and new generation in the IPM modeling framework. For example, the lifespan of existing generators in IPM can be extended through investments in ways that are not directly comparable to production with extant capital in the SAGE model. In this analysis, we attribute all incremental costs associated with existing generation to production with extant capital until 2051. Incremental costs on existing generation in model years after 2051 are levied on production with new capital.

the capital stock from targeting consistent amortized payments can be thought of as a translation of payments (e.g., a means to translate a fixed term investment into a cumulatively depreciated asset).

Because SAGE does not include an explicit representation of the Inflation Reduction Act (IRA) in the baseline, the model linkage methodology must be adjusted to account for IRA investment and production subsidies (i.e., ITC/PTC and 45Q). The SAGE-PE model is calibrated to match both the real resource requirements for the expected compliance pathway and the impact of the IRA subsidies on the compliance expenditure for the electricity sector. To accomplish this, the real resource requirements represented by the IRA subsidies are included in the incremental costs of the final rules (i.e., the incremental costs exclude subsidy payments).[146] To avoid overstating electricity price impacts and the social costs of higher electricity prices, the net tax rate on electricity sector production is also adjusted within the calibration of the SAGE-PE model to reflect the IRA subsidies that offset a portion of the compliance expenditures for the electricity sector. This approach allows the model to explicitly capture the private costs faced by the electricity sector, the upstream and downstream impacts of the resource requirements for the subsidized technologies and fuels, and changes to government budgets associated with the use of subsidies. The SAGE model is closed by assuming the government budget is balanced through lump sum transfers with households. Aggregate changes in government budgets can occur in model simulations due to changes in the use of the IRA subsidies and changes in revenues from other taxes (e.g., output, capital, and labor) as the economy adjusts in response to the final rules. Additional features of the IRA are not explicitly represented in SAGE at this time.

5.2.4 Results

This section summarizes the estimated economy-wide impacts of the final rules. We report the SAGE model outcomes from implementing the described framework for linking SAGE with IPM. Results include aggregate social costs of the final rules, changes to gross domestic product (GDP) and its components, national sectoral output, national sectoral labor

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[146] ITC/PTC subsidies are levied on capital whereas the 45Q subsidy is shared across inputs according to an assumed cost structure for carbon capture and storage based on a combination of both the natural gas extraction sector in the SAGE model and the cost structure of pipeline transportation from the Bureau of Economic Analysis. The adopted approach for modeling the costs of carbon capture and storage approximately align with information found in Ortiz et al. (2013) and McFarland and Herzog (2006).

demand changes, and distributional impacts across regions and households. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits.

5.2.4.1 Economy-wide Social Costs

Table 5-4 presents the economy-wide, general equilibrium social costs of the final rules, calculated as equivalent variation. In this context, equivalent variation is an estimate of the amount of money that society would be willing to pay to avoid the compliance requirements of the final rules, setting aside health, climate, and other benefits (quantified or described qualitatively elsewhere in the RIA). For comparison, Table 5-4 also presents the compliance costs estimated by IPM to be paid by the electricity sector for real resources – and which exclude all transfer payments – mapped to the SAGE model years. For both the compliance costs and the general equilibrium social costs, Table 5-4 presents the present value and annualized costs using a discount rate of 4.5 percent, which is consistent with the internal discount rates in the SAGE model.[147] Compliance costs and transfer changes are presented as they are input into the SAGE model. Section 5.2.3.3 discusses our assumptions for mapping IPM model years to SAGE model years. Therefore, present value and equivalent annualized value estimates of the IPM inputs to SAGE reported in Table 5-4 are not comparable to those reported in Sections 3 or 7 and are provided here for transparency and as a point of comparison for the social cost estimates.

The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using the 4.5 percent discount rate that is consistent with the internal discount rates in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate. This social cost estimate reflects the combined effects of the final rules' requirements and interactions with IRA subsidies for specific technologies that are

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[147] The SAGE model estimates the present value of costs (i.e., equivalent variation) for each representative household in the model and sums those estimates to calculate the present value of social costs. The present value of costs for a representative household is based on its calibrated intertemporal utility function and the equilibrium solution. Implicit in those estimates are endogenous discount rates that vary by household and over time. The intertemporal preferences of households are calibrated such that their average discount rate over the first 20 years of the model is consistent with a discount rate of 4.5 percent, which based on the effective marginal capital tax rate in the model, is consistent with a 7.0 percent social rate of return to capital. See Section 3.4 of the SAGE model documentation at https://www.epa.gov/environmental-economics/cge-modeling-regulatory-analysis.

expected to see increased use in response to the final rules. We are not able to identify their relative roles at this time.

The general equilibrium social costs from SAGE differ from the compliance costs excluding transfers from IPM for several reasons. First, the general equilibrium costs reflect demand responses for electricity and energy inputs as the economy (inclusive of firms and households) respond to the impacts of the final rules and shift production and consumption behavior. Second, the general equilibrium costs account for interactions with pre-existing distortions in the economy, mainly taxes and subsidies. Third, the general equilibrium costs account for effects of reallocation, potential reductions in aggregate investment, and the resulting effects on economic growth.

The compliance costs from IPM peak in the 2036 and 2041 SAGE model years. The estimated social costs are spread out more evenly over the model time horizon as the economy smooths out the impact by reallocating investment and consumption decisions. For the period from 2024 to 2047, the equivalent annualized value for social costs in the SAGE model is smaller than the annualized estimates of the compliance costs. However, the reported costs between 2024 and 2047 represent a truncated estimate of the total social costs estimated in the SAGE model, which accounts for changes in the economy after 2047 due to the forward-looking nature of the model out to the end of the model horizon, 2081.[148]

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[148] The estimated social costs are about 20 percent lower (through 2047) or 6 percent higher (through 2081) than the compliance costs from IPM (excluding transfers). The empirical literature finds that social costs for a set of generic, illustrative single sector environmental regulation scenarios are 6 percent to 33 percent larger than engineering-based compliance expenditures over the entirety of the model time horizon, noting that the specific details of the individual regulation can significantly affect the social cost estimates (A. L. Marten et al., 2019).

Table 5-4 Compliance Costs, Transfers, and Social Costs (billions of 2019 dollars)

SAGE Model Year	Compliance Costs - Input to SAGE (Excluding Transfers)	Change in Transfers - Input to SAGE	General Equilibrium Social Costs
2026	-1.46	0.10	1.14
2031	-0.32	0.05	1.27
2036	6.13	-4.79	1.37
2041	5.02	-4.44	1.48
2046	1.94	1.36	1.59
2051	0.94	0.49	1.73
2056	0.74	0.97	1.86
Present Value (2024 to 2047, 4.5%)	25.17	-21.89	19.94
Equivalent Annualized Value (2024 to 2047, 4.5%)	1.66	-1.44	1.32
Present Value (2024 to 2081, 4.5%)	30.51	-16.41	32.36
Equivalent Annualized Value (2024 to 2081, 4.5%)	1.42	-0.77	1.51

Notes: Social costs are calculated as equivalent variation. Present value and annualized cost estimates are calculated by interpolating between SAGE model years and use a discount rate of 4.5 percent, which is consistent with the internal discount rate in SAGE. Compliance costs and the change in the transfer amounts are calculated from the IPM outputs. Transfers include changes in tax payments on capital, production and investment tax credits (e.g., the 45Q tax credit), and interest payments. Negative transfer values reflect decreases in net additional payments out of the sector or increases in payments into the sector (e.g., subsidies) due to the final rules. Incremental monitoring and reporting costs are not accounted for in this analysis. Compliance costs and transfer changes are reported as they are input into the SAGE model. Section 5.2.3.3 discusses assumptions on mapping IPM model years to SAGE model years. Present value and equivalent annualized value estimates are based on this mapping and are therefore not directly comparable to estimates in Sections 3 and 7.

5.2.4.2 Impacts on GDP

The estimated percent change in real gross domestic product (GDP), or the real value of the goods and services produced by the U.S. economy, and its components are presented in Figure 5-3. GDP is defined as the sum of the value (price times quantity) of all market goods and services produced in the economy and is equal to Consumption (C) + Investment (I) + Government (G) + (Exports (X) – Imports (M)). The final rules are estimated to increase GDP in 2026 and 2031 by 0.015 percent and 0.020 percent due to increases in investment, but subsequently result in a modest decrease in GDP with a peak reduction of 0.017 percent in 2036. GDP is a measure of economic output and not a measure of social welfare. Thus, the expected social cost of a regulation will generally not be the same as the expected change in GDP (U.S. EPA, 2015).[149]

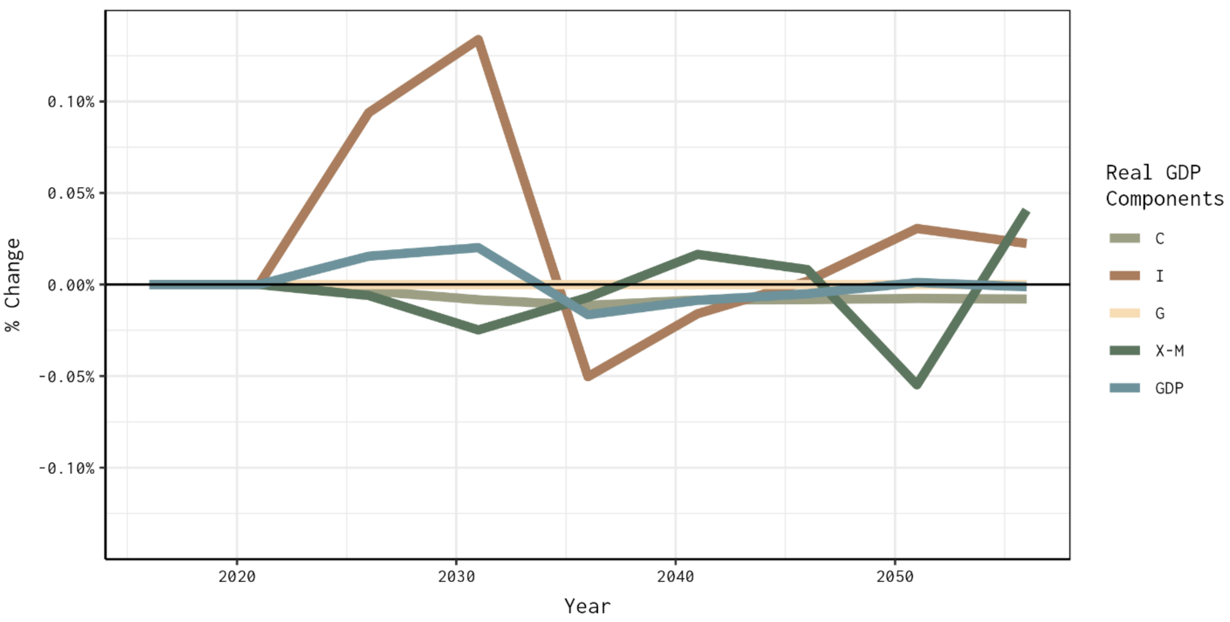

Figure 5-3 Percent Change in Real GDP and Components

Figure 5-3 also reports changes in the components of GDP from the expenditure side. The final rules are expected to accelerate investments in the electricity sector, leading to a net increase in aggregate investment in 2026 and 2031 (0.09 percent and 0.13 percent, respectively) to augment the capital stock for compliance with the rule. Increased investment reallocates resources away from consumption and as a result, consumption falls throughout the model time horizon. Aggregate investment is expected to fall in later model years. The net trade balance is expected to show modest declines in the initial years as relative prices change domestically due to compliance with the final rules, shifting some purchases towards imports, though the effect is expected to dissipate over time.

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[149] U.S. EPA Science Advisory Board (2017) notes: “GE models are strongly grounded in economic theory, which allows social costs to be evaluated using equivalent variation or other economically-rigorous approaches. Simpler measures, such as changes in gross domestic product or in household consumption, do not measure welfare accurately and are inappropriate for evaluating social costs.”

5.2.4.3 Impacts on Output

SAGE endogenously models production for every sector in the economy, the final demand for goods by households, and household behavior regarding savings and labor supply. Therefore, the general equilibrium solution incorporates estimates of how changes in the prices for electricity, coal mining, and natural gas inputs due to the final rules affect input demand in other sectors of the economy. The general equilibrium solution also estimates changes in final demand from households, the reallocation of resources across sectors and time, and changes in household investment and labor choices as relative prices change (including wages, rental rates on capital, and returns on natural resources).

Figure 5-4 presents the percent change in national output for the electricity, coal mining, and natural gas extraction and distribution sectors in model years 2026, 2031, 2036, and 2041. These output changes are based on what is expected to occur in the electricity sector as well as changes elsewhere in the economy. As expected, the largest economy-wide changes, denominated in percent change, are concentrated in these sectors. These changes reflect the estimated shifts in generation sources in addition to an economy-wide demand response to increases in electricity prices. As the price of electricity rises, the economy is expected to reduce demand for electricity through a variety of pathways. Similarly, output changes in the coal mining and natural gas reflect changes in both the electricity sector and the broader economy (inclusive of import and export changes).

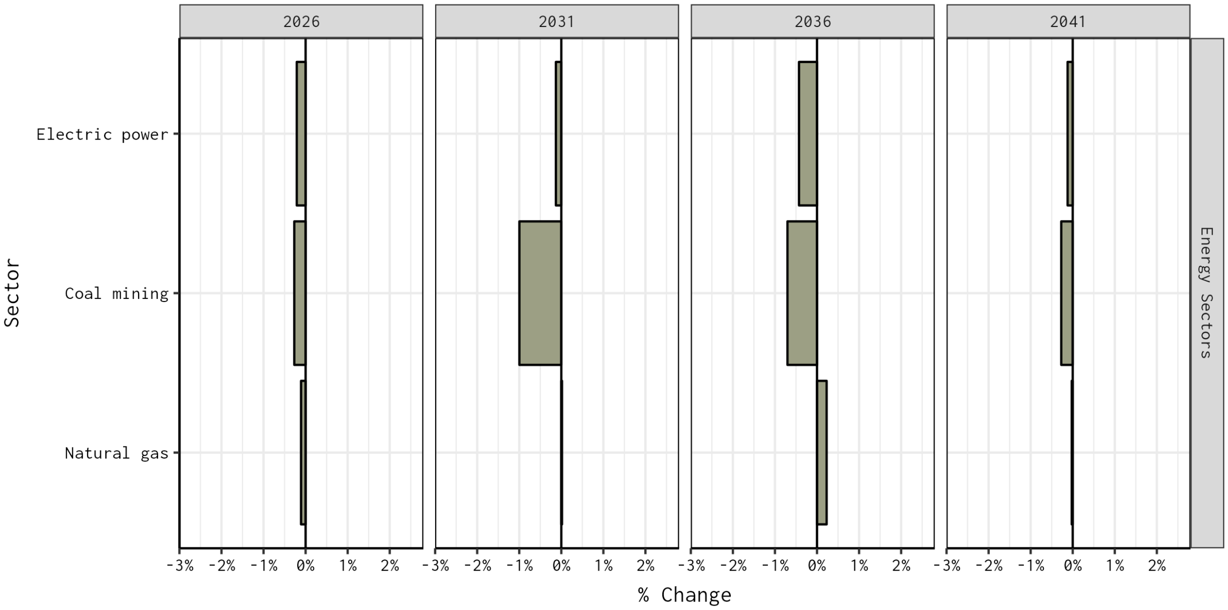

Figure 5-4 Percent Change in Sectoral Output (Electricity, Coal, Natural Gas)

Measured in terms of percent change from the baseline, output changes in other sectors of the economy are expected to be smaller relative to the electricity, coal mining, and natural gas sectors. Figure 5-5 presents the percent change in output for the remaining sectors of the economy as reflected in the SAGE model for 2026, 2031, 2036, and 2041 (note the axis scale is different than in Figure 5-4). Modest output reductions are estimated in some relatively more energy intensive sectors (e.g., chemical manufacturing) and those that support coal use in the electricity sector (e.g., transportation) whereas output increases in sectors associated with capital formation in 2026 to support investments needed to comply with final rules.

Combining output impacts across all sectors in the economy, Figure 5-6 presents the estimated net economy-wide percent changes in output in 2026, 2031, 2036, and 2041. Aggregate U.S. production is expected to increase by 0.01 percent in 2026 and by 0.02 percent in 2031, with declines of similar magnitude in subsequent years. The model suggests modest increases in production in 2026 and 2031 in capital forming sectors in anticipation of rule requirements, resulting in an overall increase in output. In later model years, output reductions in the electricity sector, primary energy sectors, and energy-intensive sectors slightly outweigh output increases elsewhere in the economy.

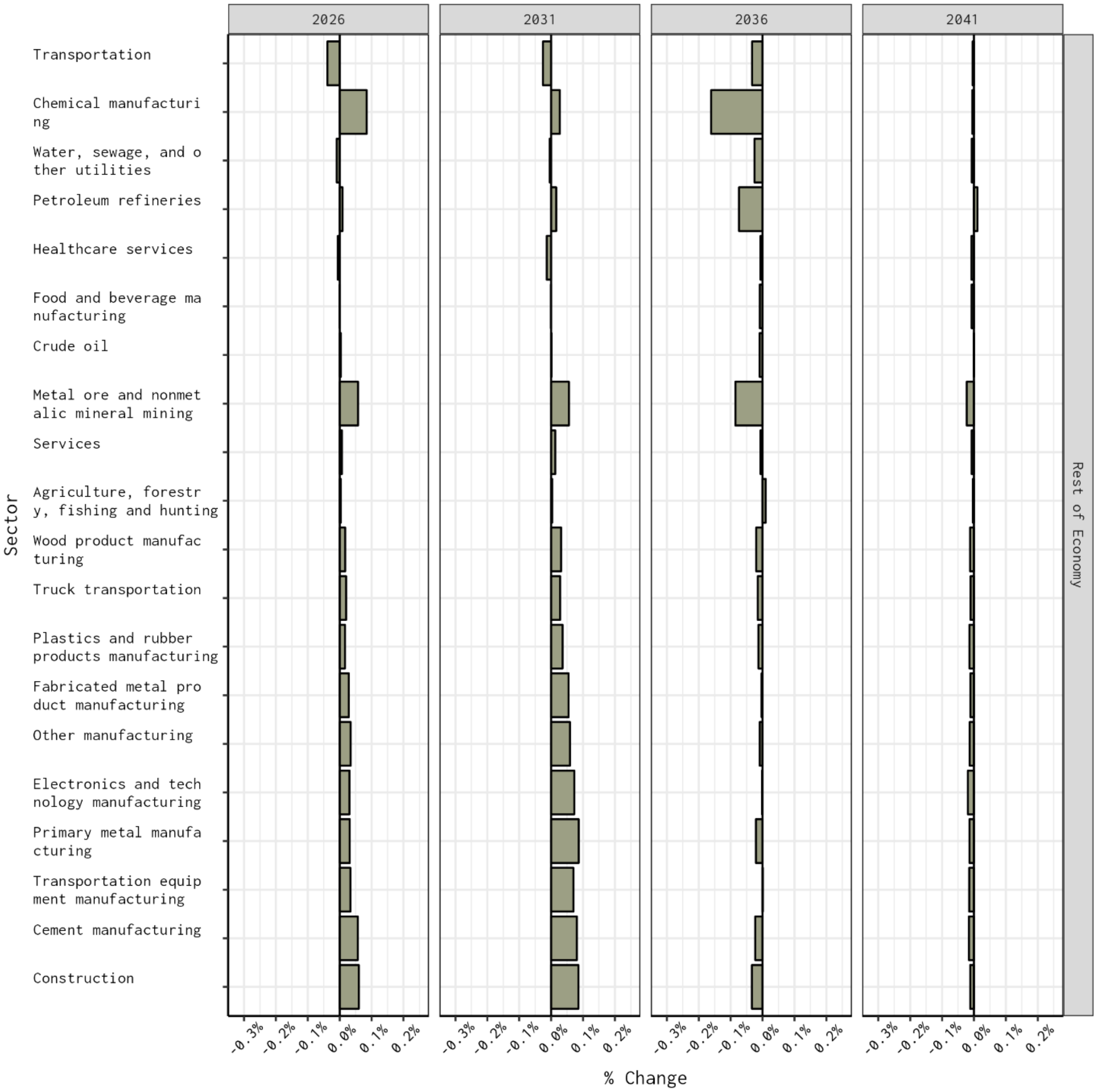

Figure 5-5 Percent Change in Sectoral Output (Rest of Economy)

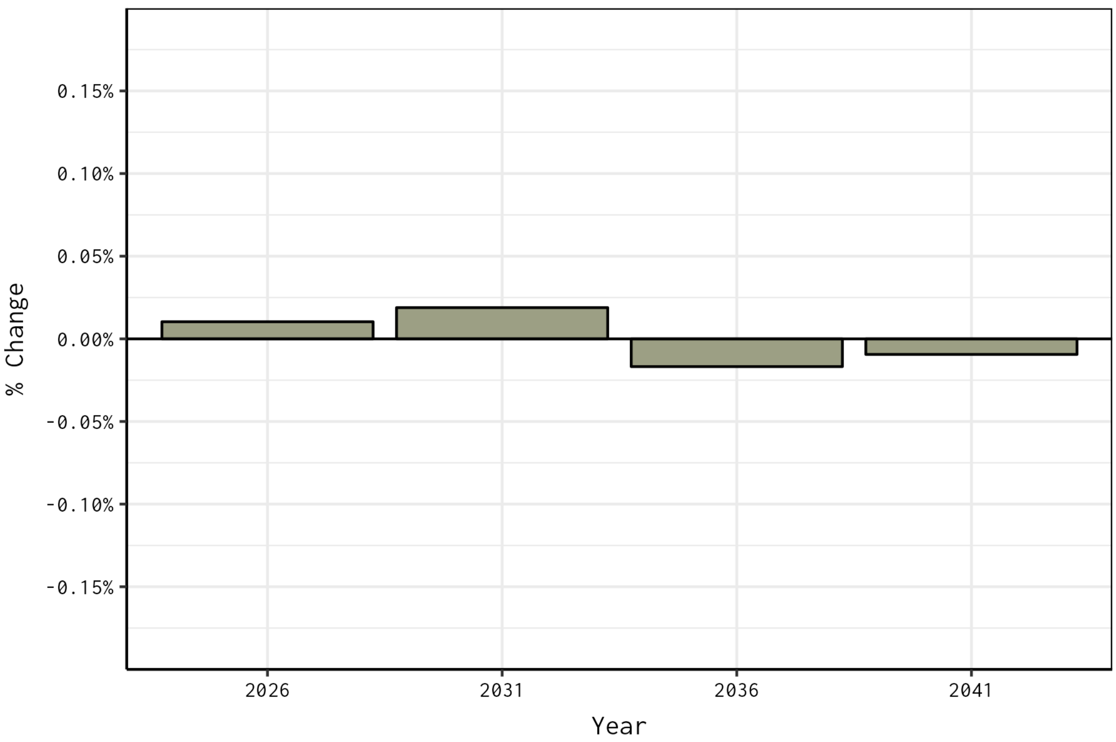

Figure 5-6 Percent Change in Economy-wide Sectoral Output (All Sectors)

5.2.4.4 Output Price Impacts

Figure 5-7 presents the percent changes in real output prices for each sector in the SAGE model in 2026, 2031, 2036, and 2041. CGE models report prices in relative terms.[150] The largest percent changes in real output prices occur in the natural gas, electricity, and coal sectors. The estimated change in the electricity sector output price reflects the additional costs associated with complying with the final rules as well as demand side reductions in electricity use from both firms and households. Estimated price changes for natural gas and coal largely reflect the changes in demand for those fuel types in the electricity sector.

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[150] Here, we denominate output prices in terms of the consumer price index (CPI) internal to the SAGE model, which reflects the overall change in end-use prices for the bundle of goods demanded by households. Characterizing prices relative to the CPI allows a comparison of changes in the magnitude of output prices to overall trends in the economy (i.e., a percentage change that is positive reflects a price that increases more than the average price changes across the economy).

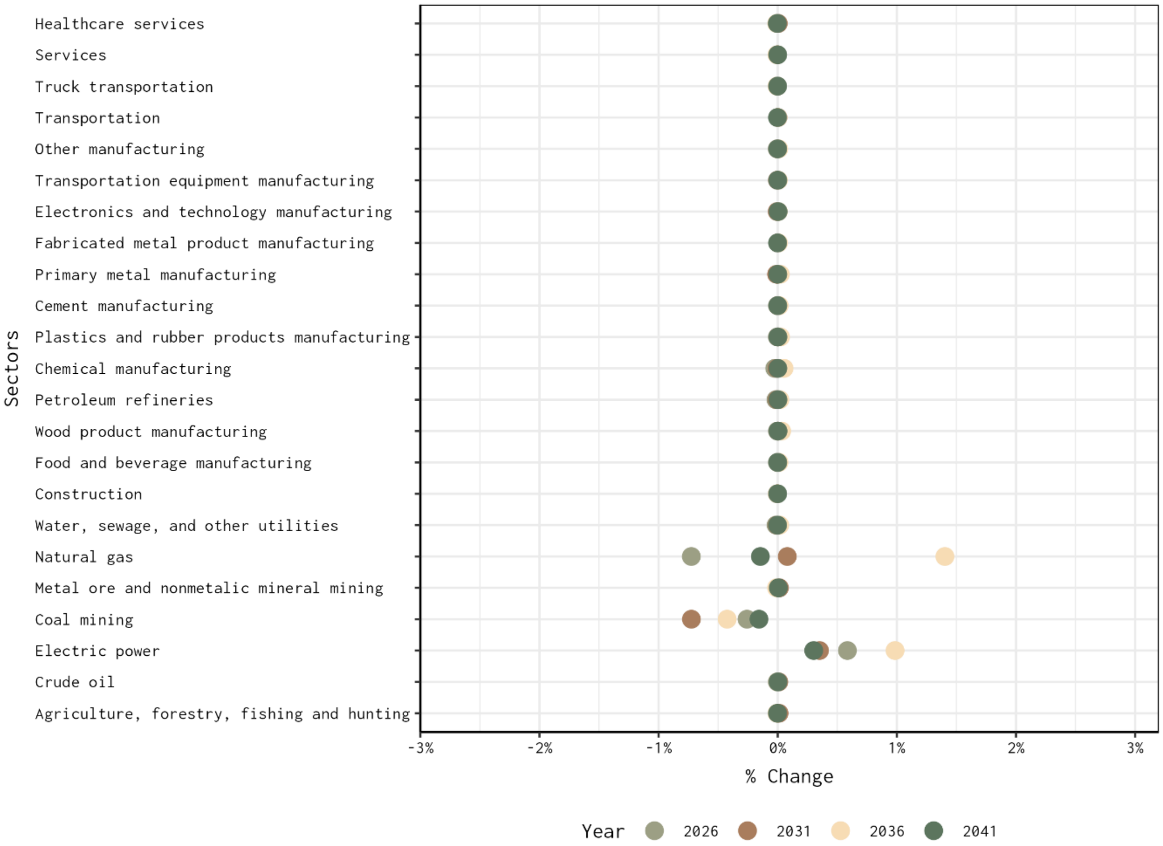

Figure 5-7 Percent Change in Real Output Prices

5.2.4.5 Labor Market Impacts

As with many other CGE models, SAGE assumes an economy with full employment, meaning that the labor market in the model adjusts to the new equilibrium such that there is no involuntary unemployment (i.e., all workers that want to work at the new prevailing wage can find a job). Any net changes in employment levels are associated with voluntary changes in labor. SAGE is therefore best suited to analyze medium to long run shifts in the expected use of labor across aggregate sectors as a result of the final rules. In contrast, Section 5.4 of this RIA characterizes employment impacts of the final rules in the power and fuels sectors, providing detailed estimates by capacity and fuel type, without accounting for changes in prices, wages, and interactions with other sectors in the economy.

While SAGE does not capture any near-term transition dynamics in the labor market, recent economics research suggests that they likely are a small component of overall welfare costs of environmental regulation. Using a one-sector growth model, Rogerson (2015) finds that explicitly accounting for labor market transitions to a new equilibrium may have minimal impact on the aggregate welfare changes associated with new regulations, though the author notes that this is a function of the transition dynamics assumed in the model. Slower transition dynamics may widen the gap between social cost measures with and without accounting for short-term transition dynamics in the labor market. Hafstead and Williams (2018) develop a two-sector CGE model that incorporates several wage-setting mechanisms where the adjustment costs from transitioning between unemployment and employment are realized at much smaller time steps than are typical in a CGE framework. The authors estimate that the net employment impacts of environmental policy may be small due to the offsets in the labor demand by unregulated sectors.

Figure 5-8 presents the percent change in net labor demand across the economy in 2026, 2031, 2036, and 2041. Shifts in aggregate labor demand are expected to occur as some sectors require fewer hours worked, some require more hours worked, and wage rates adjust to ensure there is adequate labor being voluntarily supplied by households to meet firms' demand for labor. In model years 2026 and 2031, the model estimates a small aggregate increase in the labor supply to accommodate additional labor demand across the economy needed to support additional investments occurring in anticipation of the final regulatory requirements. In subsequent model years expected reductions in output and investment result in small decreases in labor supply. Figure 5-9 presents the estimated percent change in labor demand by electricity, coal, and natural gas sectors in 2026, 2031, 2036, and 2041. In these sectors, changes in labor demand are generally reflective of the estimated output changes.

Figure 5-10 presents the percent change in sectors other than electricity, natural gas, and coal for 2026, 2031, 2036, and 2041. The increase in the labor supply in 2026 and 2031 is driven by increases in demand for labor in sectors associated with capital formation (e.g., construction, cement manufacturing) to support new investments.

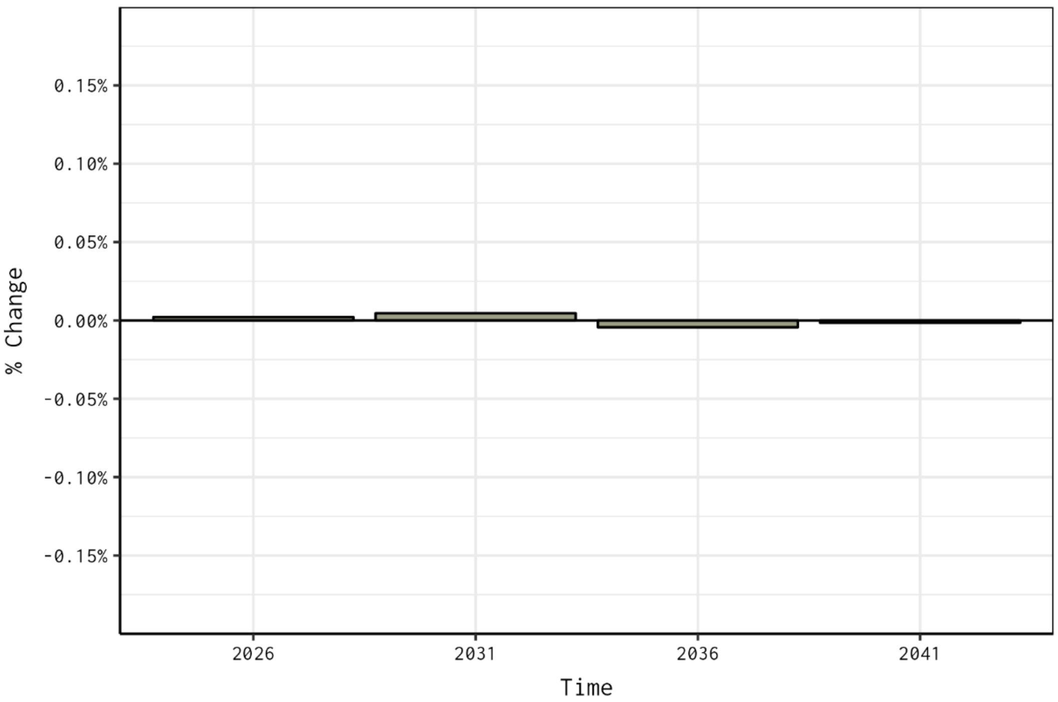

Figure 5-8 Percent Change in Economy-wide Labor Demand (All Sectors)

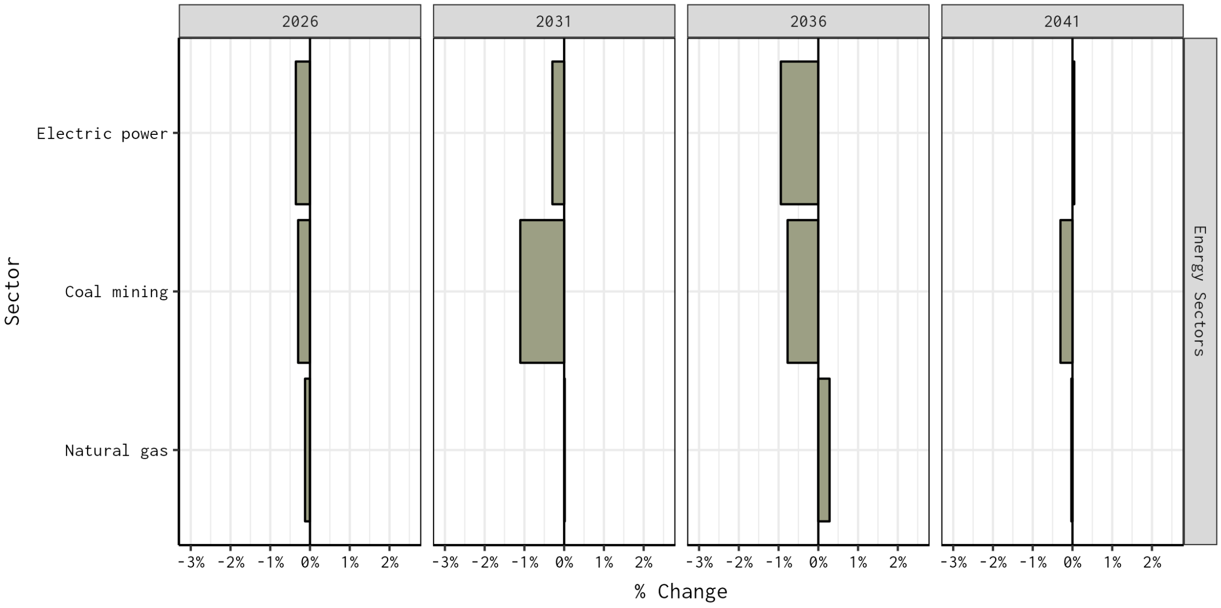

Figure 5-9 Percent Change in Labor Demand (Electricity, Coal, Natural Gas)

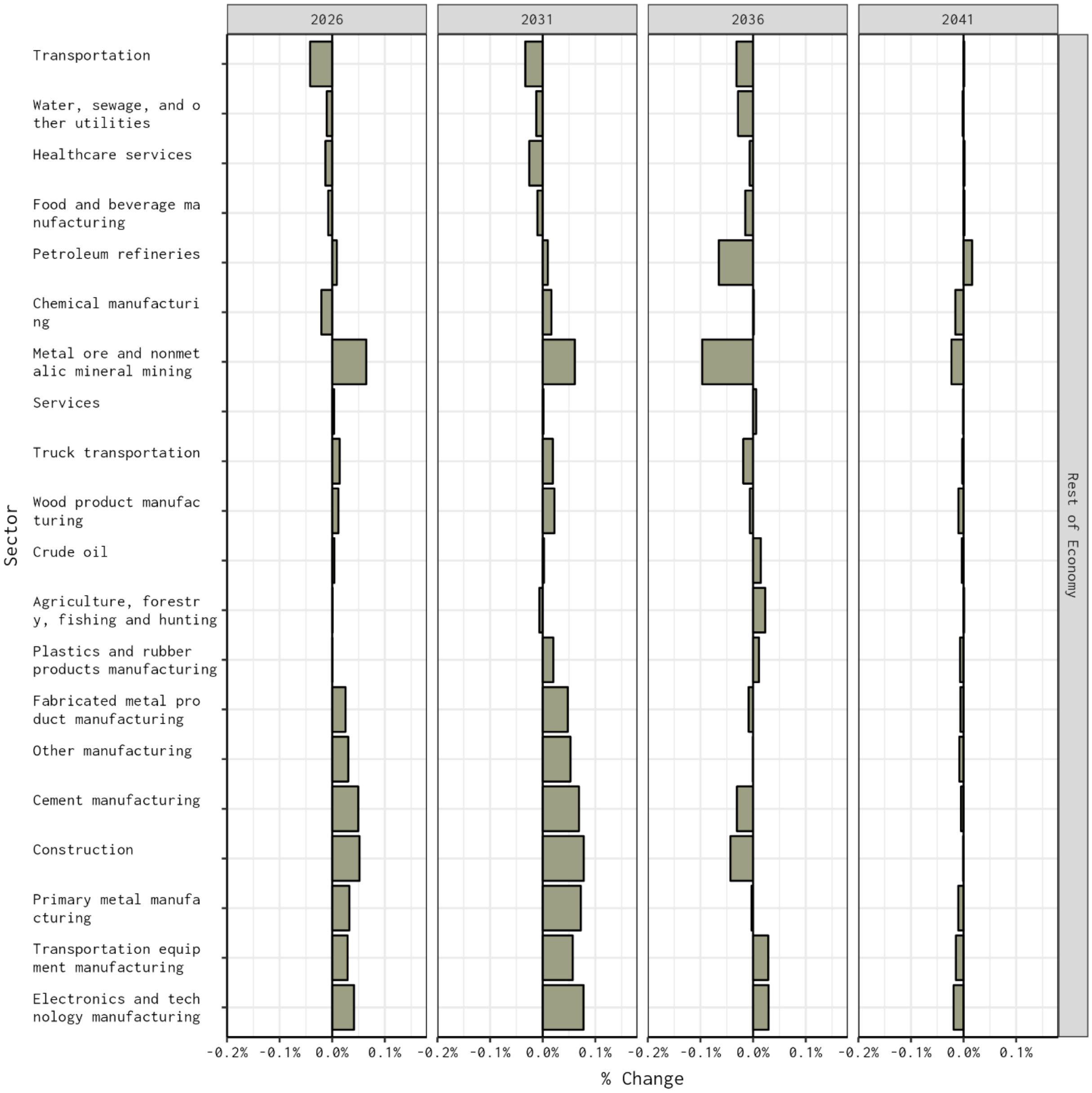

Figure 5-10 Percent Change in Labor Demand (Rest of Economy)

5.2.4.6 Household Distributional Impacts

The social costs of regulation are ultimately borne by households through changes in final goods prices or changes in labor, capital, and resource income. SAGE models representative households by income quintiles in each of the four Census regions. This allows the social costs to be separately estimated across the income distribution and for different regions of the country, as presented in Figure 5-11.[151] In general, the annualized household costs increase with income and are expected to be highest in the Western Census region and lowest in the Southern Census Region.

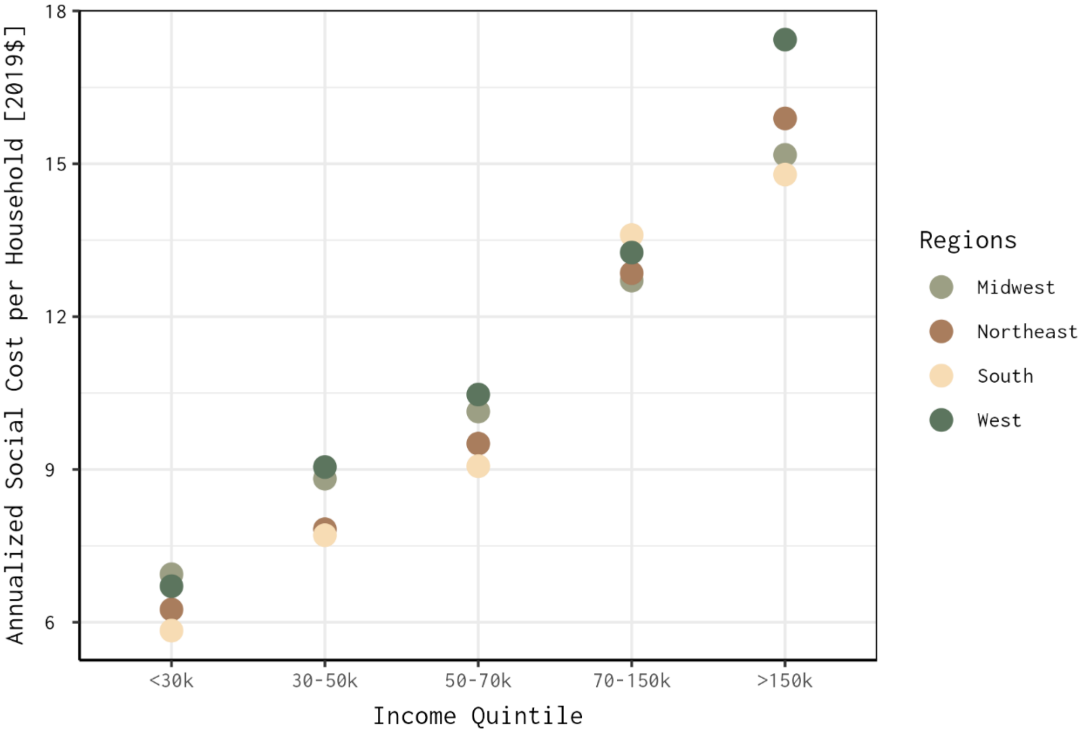

Figure 5-11 Distribution of General Equilibrium Social Costs

Estimates in Figure 5-11 reflect a combined effect of the final rules' requirements and interactions with IRA subsidies that are expected to see increased use in response to the final rules. A regulation may affect the value of government expenditures through relative prices of goods and services purchased by the government. In addition, it may affect tax revenues through impacts on the value of the base for ad valorem taxes (e.g., labor and capital taxes). In these cases, a CGE model must implement a closure rule to ensure that the government has the funds necessary to support its expenditures. A common assumption in CGE models is to balance the government's budget through lump sum transfers between households and the government as a

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[151] Distributional cost estimates are annualized for the period 2024 to 2047 and divided by the total number of households of a given income quintile and region using 2016 estimates from the Census' Current Population Survey.

non-distortionary approach to closing the model. This is the approach used in the SAGE model. Given uncertainties in the accounting for the IRA subsidies in this analysis, we are unable to determine the relative role of this effect in the distributional estimates at this time.

5.2.5 Limitations to Analysis

The SAGE model and methodology for aligning IPM outputs for use as inputs in SAGE reflect the best available science for conducting economy-wide modeling of the final rules. However, both the use of SAGE in a regulatory analysis and the framework for linking IPM with the SAGE model are subject to uncertainty and limitations:

- The costs of complying with existing regulations are largely reflected in the social accounting matrix and in projections used to calibrate the SAGE model but are not distinguished from non-regulatory related costs (i.e., there is no explicit characterization of already existing regulations in the constructed baseline). Data underlying the SAGE baseline ranges from 2016 to 2020, depending on the specific source. As a result, recent changes in the economy, including new regulations, may not be captured in the source data used to calibrate the model's baseline. For these reasons, SAGE may not explicitly capture interactions that the final rules may have with compliance activities already underway to meet existing regulatory requirements.

- Since IPM provides inputs for this SAGE analysis, the SAGE estimates are subject to many of the same uncertainties and limitations of the IPM methodology, which are detailed in Section 3. In particular, this economy-wide analysis focuses on a single illustrative compliance scenario for these final rules.

- The methodology used to align IPM and SAGE accounts for partial equilibrium feedbacks in IPM and represents an improvement over assuming the solution of one model directly in the other. While a full model linkage, where the models iteratively pass information back and forth until jointly converging to an equilibrium, may provide a more complete representation of the economy-wide impacts of the final rules, it is challenging to implement and not feasible at this time.

- To align IPM outputs for use as SAGE inputs, we target the estimated change in amortized payments to capital. However, because the representation of capital differs between IPM and SAGE, the projected stream of capital investments in response to the final rules also likely differs between the two models. See Section 5.2.3.3 for a discussion of this choice.

- Production with extant and new capital in SAGE is not equivalent to differentiating existing and new generation in the IPM modeling framework. This analysis assigns incremental costs on existing generators in IPM to production with extant capital in SAGE until model year 2051, and on production with new capital thereafter, as extant capital in the electricity sector is mostly depreciated by that point. Extant capital in SAGE is assumed to be relatively inflexible in its ability to accommodate changes in production processes when compared to new capital. Therefore, it is possible that the linked framework may over- or under-attribute incremental costs to less flexible production processes in SAGE.
- Given the level of sectoral aggregation in SAGE, subsidies on specific electricity-sector technologies are reflected in the SAGE model through a sector-wide adjustment in output taxes. This sector-wide adjustment is designed to approximate subsidies levied on specific technologies but may add a degree of uncertainty to the social cost estimate regarding the degree to which the subsidies interact with pre-existing distortions in the economy. Furthermore, this treatment of subsidies is subject to additional uncertainties related to the effective magnitude of these payments.
- The purpose of this analysis is to quantify the social cost and the economy-wide impacts of the final rules. To the extent possible, the analysis models the potential interactions between the final rules and IRA subsidies, but it is beyond the scope of this RIA to evaluate the social costs and benefits of the IRA subsidies in their entirety. Additional effects of the IRA, as they relate to the final rules, beyond the specific subsidies modeled in this RIA could result in a change in estimated social costs and other economy-wide impacts.
- SAGE assumes perfect competition within each sector, a standard assumption in CGE modeling used to ensure tractability. However, market power is itself a distortion because it moves private behavior away from the economically efficient outcome. Environmental regulations can also potentially affect the number of producers and the market structure

of the regulated sector by raising production costs, modifying economies of scale, or affecting barriers to entry. A more concentrated market can result in higher prices and lower output, increasing the social cost of a regulation relative to what is estimated under an assumption of perfect competition.

- The economy-wide analysis is limited to an evaluation of social costs. SAGE does not currently estimate changes in emissions nor account for environmental benefits. The SAB (U.S. EPA 2017) noted that CGE models "have not achieved their potential for analysis of the benefits of air regulations" because they do not account for potential interactions between costs and benefits. While this means that estimates from SAGE – and CGE models generally – are a partial representation of the total effects of regulation on the economy, the SAB stated that this "does not invalidate the use of CGE models to estimate costs."

5.3 Small Entity Analysis

5.3.1 Overview

For the final rules, EPA performed a small entity screening analysis for impacts on all affected EGUs 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 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 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 EPA on compliance with the Regulatory Flexibility Act (RFA)[152] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests

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[152] The RFA compliance guidance to EPA rule writers can be found at <https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf >

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.[153]

5.3.2 EGU Small Entity Analysis and Results

This section presents the methodology and results for estimating the impact of the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units on small EGU entities in 2035 based on the following endpoints:

- annual economic impacts of the final rule on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

This rule would affect the buildout and operation of future NGCC and NGCT additions. Costs are projected to peak in 2035, which is consistent with the imposition of the second phase of the NSPS requirements on new NGCC builds, and as such, the analysis focuses on this year. While IPM can provide important information about the future operation and addition of natural gas capacity over the analysis period, the model does not project actions taken by individual firms. Hence, as a proxy for the future gas capacity built by small entities EPA assumed that the same small entities identified using the process outlined below would continue to build the same share of future capacity additions projected by IPM over the forecast period. EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and NGCT additions as outlined in EPA National Electric Energy Data System (NEEDS) v.7 database. The NEEDS database includes operational capacity in the year of publication as well as capturing planned/committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2028.[154]

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[153] See U.S. SBA Office of Advocacy. (2017). *A Guide For Government Agencies: How To Comply With The Regulatory Flexibility Act.* Available at: https://advocacy.sba.gov/2017/08/31/a-guide-for-government-agencies-how-to-comply-with-the-regulatory-flexibility-act

[154] For details please see Chapter 4.3 IPM base case documentation, available at: https://www.epa.gov/power-sector-modeling

Based on these criteria, EPA identified a total of 58 GW of NGCC and 11 GW of NGCT units greater than 25 MW built since 2017. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. Ownership information for these assets was obtained primarily using data from Ventyx[155], supplemented by research using S&P[156] and publicly available data.

Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[157] 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.
6. **State**: Utility owned by the state.
7. **Federal**: Utility owned by the federal government.

Next, EPA used the D&B Hoover's online database, the Ventyx database, and the S&P database to identify the ultimate owners of power plant owners identified in the NEEDS 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 Hoover's).[158] In these cases,

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[155] 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.

[156] The S&P database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.capitaliq.spglobal.com

[157] 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.

[158] The D&B Hoover's 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.

the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

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.[159] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[160] and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order to understand the appropriate size standard to apply. Data from D&B Hoover's 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 5-5. 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 the historical record.

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[159] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.

[160] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/

Table 5-5 SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (number of employees)
221111	Hydroelectric Power Generation	750
221112	Fossil Fuel Electric Power Generation	950
221113	Nuclear Electric Power Generation	1,150
221114	Solar Electric Power Generation	500
221115	Wind Electric Power Generation	1,150
221116	Geothermal Electric Power Generation	250
221117	Biomass Electric Power Generation	550
221118	Other Electric Power Generation	650
221121	Electric Bulk Power Transmission and Control	950
221122	Electric Power Distribution	1,100
221210	Natural Gas Distribution	1,150

Note: This table is an example of the NAICS codes that comprised this analysis. For a complete list, please see the accompanying workbook. Based on size standards available at the following link: https://www.sba.gov/document/support--table-size-standards). Source: SBA, 2023.

EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA size standard noted in Table 5-2. 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 Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[161] In parallel, EPA also considered estimated revenues from affected EGUs based on analysis of IPM estimates for the baseline for 2035. 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.[162] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

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[161] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.

[162] 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. Using this analysis, EPA identified 20 percent of the NGCC and 31 percent of the NGCT additions over the historical period were attributed to small entities as summarized in Table 5-6 below.

Table 5-6 Historical NGCC and NGCT Additions (2017-present)

Capacity Type	Total Additions (GW)	Total Additions by Small Entities (GW)	Share of Small Entities to Total Build (%)
NGCC	57.9	11.5	20%
NGCT*	10.8	3.4	31%

Notes: (1) One small entity accounts for 1 GW of these builds (and owns 2.3 GW of currently operating capacity). (2) As the scope of the FRFA is limited to the new source performance standards, this table presents small business impacts for the capacity types of NGCC and NGCT. Small entities also own other capacity types not covered in the scope of the FRFA.

In run year 2035, a new NGCC addition can comply with the final rule by implementing efficiency improvements (if it operates at an annual capacity factor of below 50 percent), installing CCS, or co-firing hydrogen. A new NGCT addition can comply with the final rule through implementing efficiency improvements (if it operates at an annual capacity factor of below 20 percent), installing CCS or co-firing hydrogen. 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.

To attempt to account for each potential control strategy, EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ R$$

where *C* represents a component of cost as labeled[163], and Δ R represents the change in revenues, calculated as the difference in value of electricity generation between the baseline case and the rule in in 2035 for projected NGCC and NGCT additions (calculated separately), when the second phase of the NSPS is assumed to be active under the final rule.

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,

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[163] Retrofit costs include the costs of installation of CCS.

some units will generate less electricity (and thus revenues), 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 compliance costs (or increased profit). 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 a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used IPM 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, and the change in fuel costs or electricity generation revenues under the final rule relative to the baseline. These individual components of compliance costs were estimated as follows:

1. **Operating and retrofit costs** ($\Delta\ C_{Operating+Retrofit}$): The change in operating and retrofit costs under the final rule was estimated by taking the difference in projected FOM, VOM and retrofit capital expenditures between the IPM estimates for the final rule and the baseline for the NGCT and NGCC additions projected by the model.

2. **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the final rule was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the final rule and the baseline for the NGCT and NGCC additions projected by the model.

3. **Revenue:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional wholesale electricity price ($/MWh) projected by IPM, and the accredited capacity multiplied by the projected regional capacity price projected by IPM for the NGCT and NGCC additions projected by the model. The difference between this value under the baseline and the final rule constitutes the estimated change in revenue.

Once the costs of the rule were calculated in the manner described above, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

Under the compliance modeling for the final rule, NGCT additions and dispatch are higher as a result of reductions in existing coal-fired EGU capacity and generation. As a result, economic NGCT additions experience negative compliance costs in 2035. Under the compliance modeling for the final rule, economic NGCC additions dispatch at lower levels relative to the baseline when the second phase of the NSPS is active. As such, they experience positive compliance costs.

As indicated above, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by 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 final rule on NGCCs owned by small entities are summarized in Table 5-7. All costs are presented in 2019 dollars. EPA estimated the annual net compliance cost to small entities to be approximately $46 million in 2035.

Table 5-7 Projected Impact of the Final Rule on Small Entities in 2035

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost ($2019 millions)	Number of Small Entities with Compliance Costs >=1% of Generation Revenues	Number of Small Entities with Compliance Costs >=3% of Generation Revenues
Private	8	27	3	0
Co-op	5	18	0	0
Municipal	1	1	0	0
Total	**14**	**46**	**3**	**0**

Source: IPM analysis

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 14 entities that own NGCC units considered in this analysis, three are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035 and none are projected to experience compliance costs greater than or equal to 3 percent of generation revenues in 2035.

5.4 Labor Impacts

This section discusses potential employment impacts of these regulations in the power and related fuel sectors. 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, in the power and related fuel sectors. There are significant challenges when trying to evaluate the employment effects of 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. In this section, we focus on impacts on labor demand related to compliance behavior, providing detailed first-order estimates of changes in construction and non-recurring construction labor utilization for pollution control equipment and different capacity and fuel types. This analysis is a complement to the economy-wide analysis provided in Section 5.2, which projects medium to long run shifts in the expected use of labor across aggregate sectors as a result of the final rules.

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 their demand at all (Berman and Bui, 2001; Deschenes, 2018; Morgenstern et al., 2002). 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), Curtis (2018, 2020), Deschenes (2018), Ferris et al. (2014), Greenstone (2002), and Morgenstern et al. (2002).

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. Environmental regulation may also affect labor supply through changes in worker health and productivity (Zivin and Neidell, 2018). We focus our labor impacts analysis primarily on the directly regulated facilities, with an extension to other EGUs and related fuel markets.

This section discusses and projects potential employment impacts for the utility power, coal and natural gas production sectors that may result from the final rules. 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 closely 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.[164]

The results presented in this section are based on a methodology that estimates employment impacts based on differences in projections between two modeling scenarios: the baseline scenario, and a scenario that represents the implementation of the final rules. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the rules. As discussed in Section 3, there is uncertainty related to the future baseline projections. Note that there is also uncertainty related to the employment factors applied in this analysis, particularly factors informing job-years related to relatively new technologies, such as energy storage, on which there is limited data to base assumptions.

Like previous analyses, this analysis represents an evaluation of "first-order employment impacts" using a sectoral modeling approach. It includes some of the potential ripple effects of these impacts on the broader economy. While these potential ripple effects include the secondary job impacts on upstream fuel sectors including coal, natural gas, and uranium, the analysis does not account for impacts on other fuel sectors, nor does it analyze potential impacts related to transmission or distribution. This approach excludes the economy-wide employment effects of

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[164] 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.

changes to energy markets (such as higher or lower forecasted electricity prices).[165] This approach also excludes labor impacts that are sometimes reflected in a benefits analysis for an 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).

5.4.1 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.[166] 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;

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[165] Section 5.2.4.5 provides estimates of sectoral changes in employment accounting for consequent change in the economy. Relative to the sectoral analysis in this section estimating sectoral employment impacts in the power and fuels sectors, the economy-wide analysis sheds further light on the medium to longer run labor reallocation across the economy in response to the rules, although without the same resolution at the level of capacity, pollution control, and fuel type.

[166] While more recent data is available in the 2023 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 coronavirus pandemic. The 2023 report states that: “In 2020, the energy sector was deeply impacted by the COVID-19 pandemic and subsequent economic fallout. The energy sector lost nearly 840,000 jobs, contracting at a faster rate than jobs economy-wide. Last year’s United States Energy and Employment Report (USEER) showed that, by the end of 2020, the energy sector was beginning to rebound, adding back 560,000 jobs. While the energy sector as a whole has not recovered all of the jobs lost in 2020, nearly all technologies added energy jobs in 2021. Employment in transmission, distribution, and storage; energy efficiency; and motor vehicles increased across all technologies. However, energy jobs in the fuels category declined in 2021.” The annual report is available at: https://www.usenergyjobs.org/.

- 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).

For employment related to electric power generation other than coal, hydro, natural gas, geothermal, wind and solar, as well as employment required by pollution control technologies, detailed employment data is not available. Thus, EPA implements a second approach that utilizes information available in the U.S. Economic Census. These data are used to estimate labor impacts using labor intensity ratios. These factors provide a relationship between employment and 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.

5.4.2 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 with available data that are relevant to the projected impacts of the rule. Other segments not discussed here include the extraction or production of other fuels (e.g., hydrogen), energy efficiency, and transmission, distribution, and storage. The statistics presented here are based on the 2020 USEER, which reports data from 2019.[167]

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[167] While more recent data is available in the 2023 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 coronavirus pandemic. The 2023 report states that: “In 2020, the energy sector was deeply impacted by the COVID-19 pandemic and subsequent economic fallout. The energy sector lost nearly 840,000 jobs, contracting at a faster rate than jobs economy-wide. Last year’s United States Energy and Employment Report (USEER) showed that, by the end of 2020, the energy sector was beginning to rebound, adding back 560,000 jobs. While the energy sector as a whole has not recovered all of the jobs lost in 2020, nearly all technologies added energy jobs in 2021. Employment in transmission, distribution, and storage; energy efficiency; and motor vehicles increased across all technologies. However, energy jobs in the fuels category declined in 2021.” The annual report is available at: https://www.usenergyjobs.org/.

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 which 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 percent). Other components of the electric power generation workforce include utility workers (20 percent), professional and business service employees (20 percent), manufacturing (13 percent), wholesale trade (8 percent), and other (5 percent). In 2019, jobs related to solar and wind generation represent 31 percent and 14 percent of total jobs, respectively, and jobs related to coal generation represent 10 percent of total employment.

In addition to generation-related employment we also look at employment related to coal and natural gas 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 percent). The natural gas fuel sector employed about 276,000 employees in 2019. About 60 percent of those jobs were related to mining and extraction.

5.4.3 Projected Sectoral Employment Changes due to the Final Rules

Electric generating units subject to these final rules will use various GHG mitigation measures to comply. Under the modeling of the final rules, by 2030 19 GW of coal and gas capacity is estimated to install CCS (while 11 GW of coal and gas capacity are projected to install CCS under the baseline), 790 MW of coal-fired EGUs are projected to co-fire natural gas, and 20 GW of coal-fired capacity are projected to undertake coal to gas conversion (7 GW incremental to the baseline). By 2030, the final rules are projected to result in an additional 5 GW of coal retirements, by 2035 an incremental 21 GW of coal retirements, and by 2040 an incremental 14 GW of coal retirements relative to the baseline. Under the final rules in 2035, the modeling projects 2 GW fewer NGCC builds and an incremental 10 GW of NGCT additions relative to the baseline. 0.9 GW of natural gas capacity is projected to co-fire with hydrogen by 2035. 15 GW of incremental wind and solar additions are also projected to occur relative to the baseline by 2035.

Based on these power sector modeling projections, we estimate an increase of approximately 7,900 construction-related job-years related to the installation of new pollution controls under the rule in 2030 and another 10,200 construction-related job-years for new pollution controls in 2035. We estimate an increase of approximately 45,300 job-years in 2028 related to the construction of new capacity in that year, and another even larger increase of approximately 181,300 construction-related job-years in 2035 as battery storage systems are constructed. In 2030 and 2040, we estimate decreases of 21,000 construction-related job-years and 107,500 construction-related job-years, respectively. The relatively large increase and subsequent decrease results primarily from relatively small temporal changes in the projected deployment of renewable energy and battery storage capacity in the modeling. The employment factors related to battery storage are relatively high, and, as a relatively new technology on which there is limited data to base assumptions, these factors are uncertain. Without including battery storage in the total estimate, we would estimate increases in 2028, 2030, 2035, and 2045 of 46,100, 7,300, 18,300, and 42,600 job-years, respectively, related to the construction of new capacity in those years, and a decrease of 11,300 job-years in 2040.

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 5-8 represent a point estimate of incremental changes in construction jobs for each year (e.g., for a three-year construction projection, this table presents one-third of the total jobs for that project).

Table 5-8 Changes in Labor Utilization: Construction-Related (number of job-years of employment in a single year)

	2028	2030	2035	2040	2045
New Pollution Controls	<100	7,900	10,200	<100	<100
New Capacity	45,300	-21,000	181,300	-107,500	41,800

Note: These values describe changes under the final rules relative to a projected baseline. A large share of the construction-related job years is attributable to construction of energy storage, a relatively new technology on which there is limited data to base labor assumptions.

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 between 2028 and 2045. The total net estimated decrease in recurring employment in any given analysis year 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). Table 5-9 provide detailed estimates of recurring non-construction employment changes.

Table 5-9 Changes in Labor Utilization: Recurring Non-Construction (number of job-years of employment in a single year)

	2028	2030	2035	2040	2045
Pollution Controls	<100	-200	-300	<100	-100
Existing Capacity	-2,000	-3,900	-8,700	-5,100	-7,600
New Capacity	3,000	3,400	4,100	3,000	6,300
Fuels (Coal, Natural Gas, Uranium)	-1,200	-400	-800	1,100	-1,100
Coal	*-900*	*-300*	*-1,800*	*1,100*	*-1,200*
Natural Gas	*-300*	*<100*	*1,100*	*<100*	*100*
Uranium	*<100*	*<100*	*<100*	*<100*	*<100*

Note: These values describe changes under the final rules relative to a projected baseline. "<100" denotes an increase or decrease of less than 100 job-years; Numbers may not sum due to rounding

5.4.4 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. The analysis of employment impacts in this section evaluates first-order employment effects at a detailed level for construction and recurring non-construction labor utilization for pollution control equipment and different capacity and fuel types.[168] For EGUs, these final rules may result in increases and decreases over time of construction-related jobs related to the installation of new pollution controls and construction of new 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. It is important to note that this analysis does not estimate the employment

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[168] In contrast, the economy-wide analysis in Section 5.2, assumes an economy with full employment, and is most useful for understanding medium to long run shifts in the expected use of labor across aggregate sectors as a result of the final rules.

gains likely to result from the expected development and construction of new transmission and distribution capacity throughout the U.S.

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.[169] The Inflation Reduction Act also provides numerous incentives, including through tax incentives, loans, and grants, to encourage investment in communities affected by coal mine and coal power plant closures and, more broadly, communities whose economies are more-reliant on fossil fuels.[170]

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[169] 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

[170] 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

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6 ENVIRONMENTAL JUSTICE IMPACTS

6.1 Introduction

E.O. 12898 directs 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 section. Additionally, E.O. 13985 was signed to advance racial equity and support communities with EJ concerns through Federal government actions (86 FR 7009, January 20, 2021). Most recently, E.O. 14096 (88 FR 2521, April 26, 2023) strengthens the directives for achieving environmental justice that are set out in E.O. 12898. EPA defines EJ as "the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, disability, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA further defines the term just 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."[171] 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.[172] 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

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[171] See, e.g., "Environmental Justice." EPA.gov, U.S. Environmental Protection Agency, 4 Mar. 2021, https://www.epa.gov/environmentaljustice

[172] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis

groups of concern for both the baseline and regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

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 E.O. 13563, federal agencies may consider equity, human dignity, fairness, and distributional considerations, where appropriate and permitted by law. For purposes of analyzing regulatory impacts, EPA relies upon its June 2016 "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,"[173] 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. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts; (2) exacerbate existing disproportionate impacts; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

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.

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[173] 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.

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.

6.2 Analyzing EJ Impacts in These Final Rules

In addition to the benefits assessment (Section 4), EPA considers potential EJ concerns of these final rulemakings. A potential EJ concern is defined as "the actual or potential lack of fair treatment or meaningful involvement of communities with EJ concerns in the development, implementation and enforcement of environmental laws, regulations and policies."[174] For analytical purposes, this concept refers more specifically to "disproportionate impacts on communities with EJ concerns that may exist prior to or that may be created by the regulatory actions." Although EJ concerns for each rulemaking are unique and should be considered on a case-by-case basis, EPA's EJ Technical Guidance 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 actions for populations groups of concern in the baseline?
2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory actions 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 rulemakings, as well as the nature of known and potential exposures across various demographic groups. As the final rules are focused on climate impacts resulting

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[174] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis

from emissions reductions directly targeted in these rulemakings, we begin with a qualitative discussion (Section 6.3). Insight into any potential near-source pollutant emission changes associated with existing units is provided by demographic proximity analyses. Proximity analyses for new units are not feasible as their locations are unknown (Section 6.4). $PM_{2.5}$ and ozone concentration reductions due to this action are also quantitatively evaluated relative to the future baseline with respect to EJ impacts. This analysis characterizes aggregated and distributional exposures both under a future baseline and following implementation of the final regulatory options in 2028, 2030, 2035, 2040, and 2045. It is important to note that due to the relatively low emissions projected under the baseline, and the small magnitude of projected emissions and ozone and $PM_{2.5}$ concentration changes, these rules are expected to have a small impact on the distribution of exposures across each demographic group (Section 6.5). Potential $PM_{2.5}$ EJ health impacts (i.e., mortality impacts) and potential impacts of new sources are discussed qualitatively, based on other recent national quantitative analyses (Sections 6.6, 6.7).

Unique limitations and uncertainties are specific to each type of analysis, which are described prior to presentation of results in the subsections below.

6.3 GHG Impacts on Environmental Justice and other Populations of Concern

In the 2009 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 people of color 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 life stages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; persons with disabilities; those experiencing homelessness, mental illness, or substance abuse; and Indigenous or other 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), the IPCC, and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential EJ concerns

(IPCC, 2018; Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014; USGCRP, 2016, 2018). These reports conclude that less-affluent, traditionally marginalized, predominately non-White communities can be especially vulnerable to climate change impacts because they tend to have limited resources for adaptation 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 (e.g., African-American, Black, and Hispanic/Latino communities; Native Americans, particularly those living on Tribal lands and Alaska Natives), may be uniquely vulnerable to climate change health impacts in the U.S., as discussed below. In particular, the 2016 scientific assessment on *The Impacts of Climate Change on Human Health* found with high confidence that vulnerabilities are place- and time-specific, life stages 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 (USGCRP, 2016).

Per the Fourth National Climate Assessment (NCA4), "Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being" (Ebi et al., 2018). Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels. Individuals face differential exposure to criteria pollutants, in part due to the proximities of highways, trains, factories, and other major sources of pollutant-emitting sources to less-affluent residential areas. Outdoor workers, such as construction or utility crews and agricultural laborers, who frequently are comprised of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, people in communities with EJ concerns face greater housing, clean water, and food insecurity and bear disproportionate and adverse economic impacts and health burdens associated with climate change effects. They have less or limited access to healthcare and affordable, adequate health or homeowner insurance (USGCRP, 2016). Finally, resiliency and adaptation are more difficult for economically vulnerable communities; these communities have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes to limit or reduce the hazards they face. They frequently are less able to self-advocate for resources that would otherwise aid in building resilience and hazard reduction and mitigation.

The assessment literature cited in EPA's 2009 and 2016 Endangerment and Cause or Contribute Findings, as well as *The Impacts of Climate Change on Human Health*, also concluded that certain populations and life stages, including children, are most vulnerable to climate-related health effects (USGCRP, 2016). The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments – including the Fourth National Climate Assessment (USGCRP, 2018) and *The Impacts of Climate Change on Human Health in the United States* (USGCRP, 2016) – describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events (USGCRP, 2016). In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations (Ebi et al., 2018). Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event (National Academy of Sciences, 2019). In addition, children are among those especially susceptible to allergens, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

The Impacts of Climate Change on Human Health also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) are subject to many factors that contribute to vulnerability to the health impacts of climate change (USGCRP, 2016). While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African American individuals compared to White individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately more exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma. As explained earlier, climate change can exacerbate local air pollution conditions so this increase in air pollution is expected to have disproportionate and adverse effects on these communities. Locations with greater health threats include urban areas (due to, among other factors, the “heat island” effect where built infrastructure and lack of green spaces increases local temperatures), areas where airborne allergens and other air pollutants already occur at higher levels, and communities experienced depleted water supplies or vulnerable energy and transportation infrastructure.

The 2021 EPA report on climate change and social vulnerability examined four socially vulnerable groups (individuals who are low income, minority, without high school diplomas, and/or 65 years and older) and their exposure to several different climate impacts (air quality, coastal flooding, extreme temperatures, and inland flooding) (U.S. EPA, 2021). This report found that Black and African-American individuals were 40 percent more likely to currently live in areas with the highest projected increases in mortality rates due to climate-driven changes in extreme temperatures, and 34 percent more likely to live in areas with the highest projected increases in childhood asthma diagnoses due to climate-driven changes in particulate air pollution. The report found that Hispanic and Latino individuals are 43 percent more likely to live in areas with the highest projected labor hour losses in weather-exposed industries due to climate-driven warming, and 50 percent more likely to live in coastal areas with the highest projected increases in traffic delays due to increases in high-tide flooding. The report found that American Indian and Alaska Native individuals are 48 percent more likely to live in areas where the highest percentage of land is projected to be inundated due to sea level rise, and 37 percent more likely to live in areas with high projected labor hour losses. Asian individuals were found to be 23 percent more likely to live in coastal areas with projected increases in traffic delays from high-tide flooding. Persons with low income or no high school diploma are about 25 percent more likely to live in areas with high projected losses of labor hours, and 15 percent more likely to live in areas with the highest projected increases in asthma due to climate-driven increases in particulate air pollution, and in areas with high projected inundation due to sea level rise.

In a more recent 2023 report, *Climate Change Impacts on Children's Health and Well-Being in the U.S.*, EPA considered the degree to which children's health and well-being may be impacted by five climate-related environmental hazards—extreme heat, poor air quality, changes in seasonality, flooding, and different types of infectious diseases (U.S. EPA, 2023). The report found that children's academic achievement is projected to be reduced by 4–7 percent per child, as a result of moderate and higher levels of warming, impacting future income levels. The report also projects increases in the number of annual emergency department visits associated with asthma, and that the number of new asthma diagnoses increases by 4–11 percent due to climate-driven increases in air pollution relative to current levels. In addition, more than 1 million children in coastal regions are projected to be temporarily displaced from their homes annually due to climate-driven flooding, and infectious disease rates are similarly anticipated to rise, with the number of new Lyme disease cases in children living in 22 states in the eastern and midwestern U.S. increasing by approximately 3,000–23,000 per year compared to current levels. Overall, the report confirmed findings of broader climate science assessments that children are uniquely vulnerable to climate-related impacts and that in many situations, children in the U.S. who identify as Black, Indigenous, and People of Color, are limited English-speaking, do not have health insurance, or live in low-income communities may be disproportionately more exposed to the most severe adverse impacts of climate change.

Indigenous communities face disproportionate and adverse risks from the impacts of climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Indigenous communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable (Porter et al., 2014). The NCA4 (USGCRP, 2018) noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens indigenous peoples' livelihoods and economies (Jantarasami et al., 2018; USGCRP, 2018). In addition, as noted in the following paragraph, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures.

For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Native Americans' ability to respond to these conditions is impeded by limitations imposed by statutes including the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Indigenous peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of these peoples' management decisions. Additionally, NCA4 noted that Indigenous peoples generally are subjected to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Native Americans often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (disorientation, heightened exposure to $PM_{2.5}$, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC's Fifth Assessment Report also highlighted several impacts specific to Alaskan Indigenous Peoples (Porter et al., 2014). Coastal erosion and permafrost thaw will lead to more coastal erosion, rendering winter travel riskier and exacerbating damage to buildings, roads, and other infrastructure—impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's indigenous people. In terms of food security, the

NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA4 also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

6.4 Demographic Proximity Analyses of Existing Facilities

Demographic proximity analyses allow one to assess communities with EJ concerns residing near affected facility 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 location including noise, odors, traffic, and emissions under these EPA actions.

Although baseline proximity analyses are presented here, several important caveats should be noted. It should be noted that 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 questions from EPA’s EJ Technical Guidance.

Demographic proximity analyses were performed for all plants with at least one coal-fired unit greater than 25 MW that do not have known retirement plans before 2032 (or has gas conversion plans) that are affected by these rulemakings. Due to some plants having known retirement plans, the following subsets of affected facilities were separately evaluated. For each subset, comparisons of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities were made to average national levels.

- All Coal plants subject to the rules (114 facilities, 99 GW).
- Coal plants subject to the rules that have known retirement plans between 2033 and 2040 (23 facilities, 29 GW).
- Coal plants subject to the rules without known retirement plans before 2040 (94 facilities, 70 GW).

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. 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 each block's population provided by the 2020 decennial Census.[175] 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 2016 to 2020. 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 without a high school diploma, the percentage that are below the poverty level, the percentage that are below two times 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., 5 km, 10 km, or 50 km) for all facilities was also computed (e.g., all EGUs subject to the 111 rules). 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., 5 km, 10 km, or 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, or 50 km) to the demographic composition of the nationwide population. The methodology and the results of the demographic analyses for the final rules are presented in the technical report, *Analysis of Demographic Factors for Populations Living Near Coal-Fired Electric Generating Units (EGUs) for the Section 111 NSPS and Emissions Guidelines – Final*, available in the docket for these actions. The docket also contains the detailed demographic spreadsheets with facility-specific demographic data.

Table 6-1 through Table 6-3 show the results of the proximity analysis for the three sets of affected facilities investigated at the 5 km radius, 10 km radius and the 50 km radius, respectively. Approximately 564,000 people live within 5 km of the 114 coal plants, 2.6 million

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[175] 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 specific radius. It is unknown how sensitive these results may be to different methods of population estimation, such as aerial apportionment.

people live within 10 km, and 40 million live within 50 km. It should be noted that at the 5 km radius, two facilities have zero population living within 5 km and another 10 facilities have less than 100 people living within 5 km. For facilities where the population is zero, there are no demographics data, and for those where the population is very low, the uncertainty in demographics data may be high. Therefore, in addition to the 5 km radius, we conducted proximity analyses at 10 km and 50 km, which provide more robust population data. At the 10 km radius, there were no facilities with zero population data and only two facilities had populations of less than 100 people living within 10 km. For the 50 km radius, at least 10,000 people were living within 50 km of each facility.

The analysis indicates that, on average for all 114 facilities subject to the final rules, the percent of the population that is American Indian within 5 km and 10 km of the plants (1 percent and 0.8 percent, respectively) is above the national average (0.6 percent). This is largely driven by seven facilities that have a percent American Indian population living within 5 km and 10 km ranging from 10 percent to just over 40 percent. The percent of the population within 5 km and 10 km that is living below poverty (14 percent for both) and below 2 times the poverty level (34 percent and 33 percent, respectively) is above the corresponding national averages (13 percent and 29 percent). The percentage of the population living within 50 km of the facilities that is Black (13 percent) is above the national average (12 percent). The age distributions of the populations living within 5 km, 10 km, and 50 km are similar to the national average distribution.

For the 23 facilities with known retirement plans from 2033 to 2040, the percentages of the population living within 5 km and 10 km of these units that are living below the federal poverty level (14 percent for both) and below 2 times the federal poverty level (33 percent and 31 percent, respectively) are above their corresponding national averages (13 percent and 29 percent). When we look at the population living within 50 km of these 23 facilities, we see that a larger percentage of the population is Black (14 percent), which is above the national average (12 percent). The age distributions of the populations living within 5 km, 10 km, and 50 km are similar to the national average distribution.

Since the population living around the 94 facilities for which EPA is unaware of plans to retire before 2040 accounts for about 85 percent of the population living around all 114 units subject to the final rules, the demographics are nearly identical.

It is important to note that any incremental deployment of CCS under these rules could occur within this group of 94 facilities. Several environmental justice organizations and community representatives raised significant concerns about the potential health, environmental, and safety impacts of CCS. As discussed in section VII.C of the preamble, the EPA recognizes that use of this technology can, under some circumstances, result in the increase in emission of certain co-pollutants at a coal-fired steam generating unit. While there are protections in place that can mitigate these impacts, it is important to consider the population living nearby any facility where there may be potential for these impacts to occur. Given the uncertainty regarding where installations may occur and the extent to which local emissions might be affected, the EPA is providing detailed information for each of the 94 facilities discussed above, at which installation of CCS is possible. This information is being provided in the document titled: *Analysis of Demographic Factors for Populations Living Near Coal-Fired Electric Generating Units (EGUs) for the Section 111 NSPS and Emissions Guidelines and Potential Emissions Changes* which is available in the docket. This document presents information on the populations living within 5 km and 10 km of facility, as well as the potential emissions implications of installing CCS absent the implementation of any protections discussed in section VII.C of the preamble. While the EPA projects that only a subset of this capacity is likely to install this technology, this information is being provided for all units out of abundance of caution, and to assist all states and stakeholders in considering options for state plans.

Table 6-1 Proximity Demographic Assessment Results Within 5 km of Coal-Fired Units Greater than 25 MW Affected by these Final Rules [a,b,c]

Demographic Group	Nationwide Average for Comparison	All Coal Plants subject to the rules	Coal Plants with known retirement plans from 2033 to 2040 subject to the rules	Coal Plants without known retirement plans before 2040 subject to the rules
Population within 5 km				
Total Population	329,824,950	564,492	87,230	494,112
Number of Facilities	-	114[c]	23[c]	94[c]
Race and Ethnicity by Percent				
White	60%	78%	90%	75%
Black	12%	8%	3%	9%
American Indian	0.6%	1%	0.2%	1.2%
Hispanic or Latino	19%	9%	4%	9%
Other and Multiracial	9%	5%	4%	5%
Age By Percent				
Age 0 to 17 years	22%	22%	22%	22%
Age 18 to 64 years	62%	60%	60%	60%
Age ≥ 65 years	16%	18%	18%	18%
Income by Percent				
Below Poverty Level	13%	14%	14%	14%
Below 2x Poverty Level	29%	34%	33%	34%
Education by Percent				
>25 and w/o a HS diploma	12%	12%	12%	12%
Linguistically Isolated by Percent				
Linguistically Isolated	5%	2%	1%	2%

[a] The nationwide population count and all demographic percentages are based on the Census' 2016-2020 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts are based on the 2020 Decennial Census block populations.

[b] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, Black, American Indian, Other and Multiracial, or Hispanic/Latino. 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. Includes white and nonwhite.

[c] For all coal plants subject to the rule, two facilities have zero population within 5 km and another 10 facilities have less than 100 people living within 5 km. In the group of plants with known retirement plans from 2033 to 2040, one facility had zero population within 5 km. In the group of plants without known retirement plans before 2040, one facility had zero population within 5 km, and 10 facilities had less than 100 people living within 5 km. For facilities where the population is zero, there is no demographics data and for those where the population is low, the uncertainty in the demographics data may be high.

Table 6-2 Proximity Demographic Assessment Results Within 10 km of Coal-Fired Units Greater than 25 MW Affected by these Final Rules [a,b]

Demographic Group	Nationwide Average for Comparison	All Coal Plants subject to the rules	Coal Plants with known retirement plans from 2033 to 2040 subject to the rules	Coal Plants without known retirement plans before 2040 subject to the rules
Population within 10 km				
Total Population	329,824,950	2,574,398	414,646	2,289,025
Number of Facilities	-	114	23	94
Race and Ethnicity by Percent				
White	60%	72%	87%	70%
Black	12%	10%	4%	11%
American Indian	0.6%	0.8%	0.4%	0.8%
Hispanic or Latino	19%	12%	4%	12%
Other and Multiracial	9%	6%	5%	6%
Age By Percent				
Age 0 to 17 years	22%	23%	21%	23%
Age 18 to 64 years	62%	60%	63%	61%
Age ≥ 65 years	16%	17%	17%	17%
Income by Percent				
Below Poverty Level	13%	14%	14%	14%
Below 2x Poverty Level	29%	33%	31%	33%
Education by Percent				
>25 and w/o a HS diploma	12%	11%	9%	11%
Linguistically Isolated by Percent				
Linguistically Isolated	5%	3%	1%	3%

[a] The nationwide population count and all demographic percentages are based on the Census' 2016-2020 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts are based on the 2020 Decennial Census block populations.

[b] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, Black, American Indian, Other and Multiracial, or Hispanic/Latino. 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. Includes white and nonwhite.

Table 6-3 Proximity Demographic Assessment Results Within 50 km of Coal-Fired Units Greater than 25 MW Affected by these Final Rules [a,b]

Population within 50 km				
Demographic Group	**Nationwide Average for Comparison**	**All Coal Plants subject to the rules**	**Coal Plants with known retirement plans from 2033 to 2040 subject to the rules**	**Coal Plants without known retirement plans before 2040 subject to the rules**
Total Population	329,824,950	40,143,893	12,196,836	34,070,688
Number of Facilities	-	114	23	94
Race and Ethnicity by Percent				
White	60%	69%	73%	69%
Black	12%	13%	14%	12%
American Indian	0.6%	0.5%	0.4%	0.5%
Hispanic or Latino	19%	11%	7%	12%
Other and Multiracial	9%	6%	6%	6%
Age By Percent				
Age 0 to 17 years	22%	22%	22%	22%
Age 18 to 64 years	62%	61%	61%	61%
Age ≥ 65 years	16%	17%	17%	17%
Income by Percent				
Below Poverty Level	13%	12%	12%	12%
Below 2x Poverty Level	29%	29%	28%	29%
Education by Percent				
>25 and w/o a HS diploma	12%	10%	10%	10%
Linguistically Isolated by Percent				
Linguistically Isolated	5%	3%	2%	3%

[a] The nationwide population count and all demographic percentages are based on the Census' 2016-2020 American Community Survey five-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts are based on the 2020 Decennial Census block populations.

[b] To avoid double counting, the "Hispanic or Latino" category is treated as a distinct demographic category for these analyses. A person is identified as one of five racial/ethnic categories above: White, Black, American Indian, Other and Multiracial, or Hispanic/Latino. 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. Includes white and nonwhite.

6.5 EJ $PM_{2.5}$ and Ozone Exposure Impacts

This EJ air pollutant exposure[176] analysis aims to evaluate the potential for EJ concerns related to $PM_{2.5}$ and ozone exposures[177] among communities with EJ concerns. To assess EJ ozone and $PM_{2.5}$ exposure impacts, we focus on the first and third of the three EJ questions from EPA's 2016 EJ Technical Guidance, [178] which ask if there are potential EJ concerns associated with stressors affected by the regulatory actions for population groups of concern in the baseline and if those potential EJ concerns in the baseline are exacerbated, unchanged, or mitigated under the regulatory options. [179] To address these questions with respect to the $PM_{2.5}$ and ozone exposures, EPA developed an analytical approach that considers the purpose and specifics of these final rules, as well as the nature of known and potential exposures and impacts. Specifically, as 1) these rules affect 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 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 $PM_{2.5}$ and ozone air quality surfaces under the baseline and regulatory options, we conduct an analysis of changes in $PM_{2.5}$ and ozone concentrations resulting from the emission changes projected by IPM[180] to occur under these

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[176] The term exposure is used here to describe estimated $PM_{2.5}$ and ozone concentrations and not individual dosage.

[177] Air quality surfaces used to estimate exposures are based on 12 km grids. Additional information on air quality modeling can be found in the air quality modeling information section.

[178] 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

[179] 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 6.8).

[180] As discussed in greater detail in Section 3, IPM is a comprehensive electricity market optimization model that can evaluate the impacts of regulatory actions affecting the power sector within the context of regional and national electricity markets. IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. The model computes optimal capacity that combines short-term

rules as compared to the baseline scenario, characterizing average and distributional exposures following implementation of the regulatory options in 2028, 2030, 2035, 2040, and 2045. However, several important caveats of this analysis are as follows:

- The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA.
- Although several future years were assessed for health benefits associated with these final rulemakings, there was high year-to-year $PM_{2.5}$ and ozone concentration change variability across modeled future years.
- The baseline scenarios for 2028, 2030, 2035, 2040, and 2045 represent EGU emissions expected in 2028, 2030, 2035, 2040 and 2045 respectively, but emissions from all other sources are projected to the year 2026. The 2028, 2030, 2035, 2040, and 2045 baselines therefore do not capture any anticipated changes in ambient ozone and $PM_{2.5}$ between 2026 and 2028, 2030, 2035, 2040, or 2045 that would occur due to emissions changes from sources other than EGUs.
- Modeling of post-policy air quality concentration changes are based on state-level emission data paired with facility-level baseline 2026 emissions that were available in the summer 2021 version of IPM. While the baseline spatial patterns represent 12 km grid resolution ozone and $PM_{2.5}$ concentrations associated with the facility level emissions described above, the post-policy air quality surfaces will capture expected ozone and $PM_{2.5}$ changes that result from state-to-state emissions changes by fuel type but will not capture heterogenous changes in emissions from multiple facilities of the same fuel-type within a single state (i.e. all coal EGU sources within each state are assumed to increase or decrease in

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dispatch decisions with long-term investment decisions. IPM runs under the assumption that electricity demand must be met and maintains a consistent expectation of future load. IPM outputs include the air emissions resulting from the simulated generation mix unison and all natural gas EGU sources within each state are assumed to increase or decrease in unison for the purpose of creating air quality surfaces).

- Air quality simulation input information is at a 12 km 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 eight-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 $PM_{2.5}$.
- $PM_{2.5}$ 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.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, life expectancy, linguistic isolation, poverty status, redlined areas, Tribal land, age, and sex (Table 6-4).[181,182,183,184]

Note that these variables are different than those used in the proximity analysis because criteria pollutants have nationwide impacts rather than the localized impacts that are investigated in a proximity analysis. Variables such as life expectancy, redlining, and health insurance status that are not included in the localized demographic proximity analysis are included in the nationwide criteria pollutant exposure analysis as a way to account for various vulnerabilities and susceptibilities that already exist in the nationwide population due to cumulative risks from multiple exposures (such as other pollutant exposures, stress, lack of access to healthcare, etc). There are also fewer demographic uncertainties at a national scale which allows us to use an expanded set of variables for a nationwide analysis.

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[181] Population projections stratified by race/ethnicity, age, and sex are based on economic forecasting models developed by Woods and Poole (Woods & 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. 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).

[182] EPA acknowledges the recent comments about cumulative risk assessment and is currently in the process of developing cumulative risk assessment methods for our quantitative environmental justice analyses. In the interim, the 111 EGU rulemakings utilize the "life expectancy" and "redlining" variables as a proxy to identify communities with higher or lower exposure to cumulative risks. The choice of comparing the top 75% vs the bottom 25% of life expectancy was made by finding the natural cut-off point in the distribution of life expectancies across the contiguous U.S. EPA continues to improve its methodology based on its framework for a Cumulative Risk Assessment as well as guidance from multiple Executive Orders and intend to more accurately assess cumulative risk in future rulemakings.

[183] The Tribal Land variable was also added in response to recent Executive Orders that have emphasized the need for more detailed analysis on the impacts on American Indians. The Tribal Lands variable focuses specifically on populations who live on Tribal lands in addition to quantifying those whose race is Indian American but may or may not live on Tribal lands.

[184] An additional population variable that is not included in this analysis is persons with disability. Persons with disability is a new environmental justice metric listed in E.O. 14096 (88 FR 25251, April 26, 2023), and EPA is currently developing analytical techniques/tools to evaluate its impact on our environmental analyses.

Table 6-4 Demographic Populations Included in the Ozone and $PM_{2.5}$ EJ Exposure Analysis

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
Life Expectancy	Top 75%; Bottom 25%	0-99	Census tract
Linguistic Isolation	Speaks English "well or better"; Speaks English < "well"	0-99	Census tract
Poverty Status	Above the poverty line Below the poverty line	0-99	Census tract
Redlined Areas	HOLC Grades A-C; HOLC Grade D; Not graded by HOLC	0-99	Census tract
Tribal Land	Tribal land; Not Tribal land	0-99	Census tract
Age	Children	0-17	Census tract
	Adults	18-64	
	Older Adults	65-99	
Sex	Female; Male	0-99	Census tract

6.5.1 Populations Predicted to Experience $PM_{2.5}$ and Ozone Air Quality Changes

The EPA analyzed several illustrative compliance scenarios[185] representing potential compliance outcomes and projects that, relative to a projected future baseline, these actions achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including NO_X, SO_2, and $PM_{2.5}$, resulting in significant public health benefits. In all years, the final rules are expected to result in modest but widespread reductions in ambient levels of $PM_{2.5}$ and ozone concentrations over many areas of the US, although some areas may experience increases in ozone concentrations relative to forecasted future baselines without the rule. Relative to 2028 baseline conditions, our analysis indicates that ozone and $PM_{2.5}$ will decline in virtually areas of the country. However, some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ pollution over time as a result of the changes in generation and utilization resulting from the rule.

To best assess these modeled increases and decreases in emissions and evaluate their impact on communities with EJ concerns, the contiguous U.S. was first grouped into areas where

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[185] The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the final rules, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. Additionally, the way that EGUs comply with the GHG mitigation measures may differ from the methods forecast in the modeling for this RIA.

air quality 1) does not change or improves, or 2) worsens as a result of the final rulemakings relative to a projected year's future baseline. Note that national emissions reduction estimates vary by year, with 2035 being the snapshot future year in which emission reductions are projected to be largest (Table 3-5). In the contiguous U.S., it is estimated that at least 75 percent of the U.S. population is predicted to experience air quality improvements (or a lack of change) for $PM_{2.5}$ under all scenarios analyzed except for the 2040 regulatory options, in which approximately 26-58 percent of the U.S. population is predicted to experience a $PM_{2.5}$ air quality improvement (Figure 6-1). Similarly, it is estimated that at least 65 percent of the U.S. population is predicted to experience ozone improvements (or a lack of change) due to the rulemakings for ozone under all scenarios analyzed with the exception of the 2040 regulatory options. In absolute terms, this equates to up to 77 million people experiencing worsening $PM_{2.5}$ concentrations (or up to 292 million in the 2040 final rules regulatory option) and up to 126 million people experiencing worsening ozone concentrations (or up to 313 million in the 2040 alternative 2 regulatory option). The average magnitudes of worsening $PM_{2.5}$ concentration changes due to the rulemakings round to 0.00 $\mu g/m^3$ and are much smaller than the average magnitudes of improving $PM_{2.5}$ concentration changes (which round to 0.01 – 0.04 $\mu g/m^3$). The average magnitudes of worsening ozone concentration changes (which round to 0.00 – 0.03 ppb) are also smaller than that of improving ozone concentration changes (which round to 0.02 – 0.09 ppb).

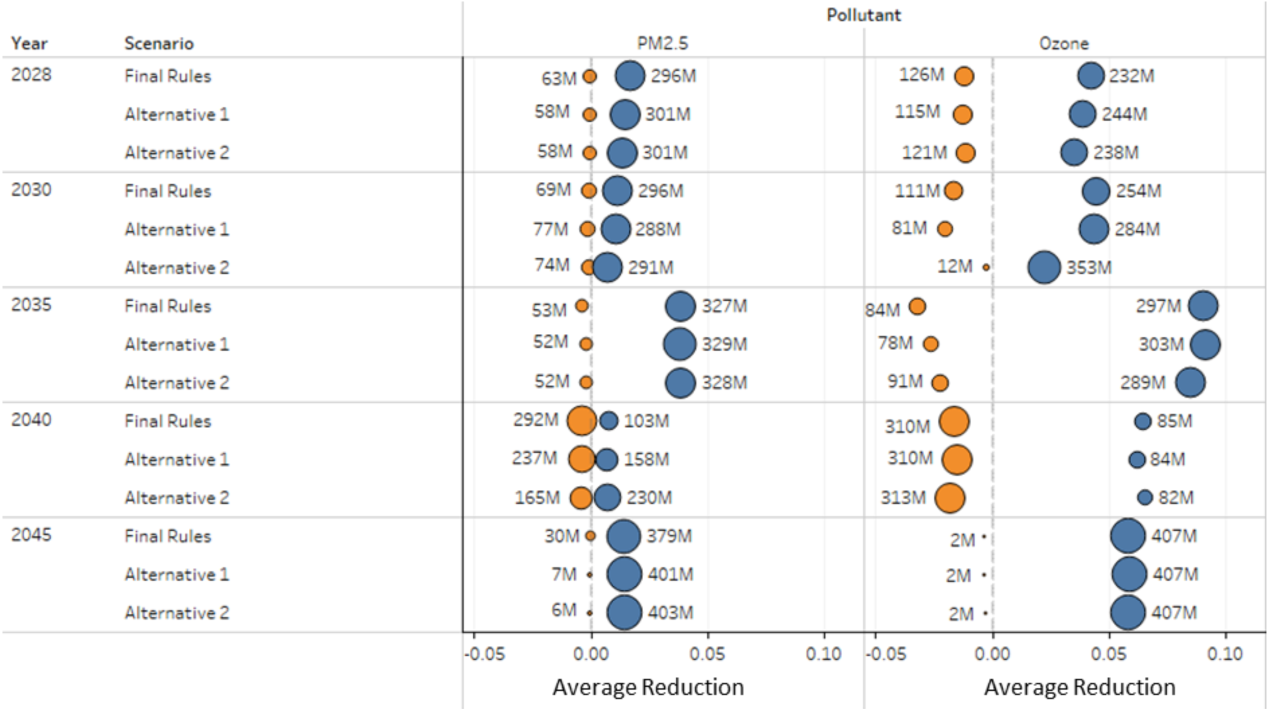

Figure 6-1 Number of People Residing in the Contiguous U.S. Areas Improving or Not Changing (Blue) or Worsening (Orange) in 2028, 2030, 2035, 2040, and 2045 for $PM_{2.5}$ and Ozone and the National Average Magnitude of Pollutant Concentration Reductions (µg/m^3 and ppb) for the 3 Regulatory Options

6.5.2 *$PM_{2.5}$ EJ Exposure Analysis*

We evaluated the potential for EJ concerns among communities with EJ concerns resulting from exposure to $PM_{2.5}$ under the baseline and regulatory options in these rules. This was done by characterizing the average and distribution of $PM_{2.5}$ exposures both prior to and following implementation of the three regulatory options (the final rules option, as well as the alternative regulatory options), in 2028, 2030, 2035, 2040, and 2045. As this analysis is based on the same $PM_{2.5}$ spatial fields as the benefits assessment (see Section 3 for a discussion of the spatial fields), it is subject to similar types of uncertainty (see Sections 3.8 and 4.3.8 for discussions of uncertainty). A particularly germane limitation for this analysis is that the expected concentration changes are quite small, likely making uncertainties associated with the various input data more relevant.

6.5.2.1 National Aggregated Results

National average baseline $PM_{2.5}$ concentrations in micrograms per cubic meter (µg/m^3) in 2028, 2030, 2035, 2040, and 2045 are shown in the Figure 6-2 heat map. Concentrations represent the total estimated $PM_{2.5}$ exposure burden averaged over the 12-month calendar year and are colored to visualize differences more easily in average concentrations (lighter blue coloring representing smaller average concentrations and darker blue coloring representing larger average concentrations). When looking across all five future years, all demographic groups will see improving $PM_{2.5}$ concentrations over time in the baseline such that the average concentration experienced by each demographic group will be less in 2030 than in 2028, less in 2035 than in 2030, and so on. When looking within each future year's baseline, average national disparities observed in the baseline of these rules are similar to those described by recent rules (e.g., the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter[186]), that is, populations with national average $PM_{2.5}$ concentrations higher than the reference population ordered from most to least difference are: those who are residents of HOLC Grade D (i.e., redlined) census tracts, linguistically isolated, residents of HOLC Grade A-C (i.e., not redlined) census tracts, Hispanic populations, Asian populations, those without a high school diploma, and Black populations (Figure 6-2).

In Figure 6-3, columns labeled "Final Rules" "Alternative 1," and "Alternative 2" provide information regarding how all three regulatory options will impact $PM_{2.5}$ concentrations across various populations, respectively.[187] While the national-level $PM_{2.5}$ concentration reductions were similar for all population groups evaluated in 2028, 2030, and 2045, the reductions were higher in 2035 and lower in 2040. Differences in reductions were also more notable in 2035. For example, (Figure 6-3), for all scenarios, the linguistically isolated, Asian population, and Hispanic population, which have higher average baseline exposures, are estimated to experience slightly smaller $PM_{2.5}$ concentration reductions than the overall reference population.

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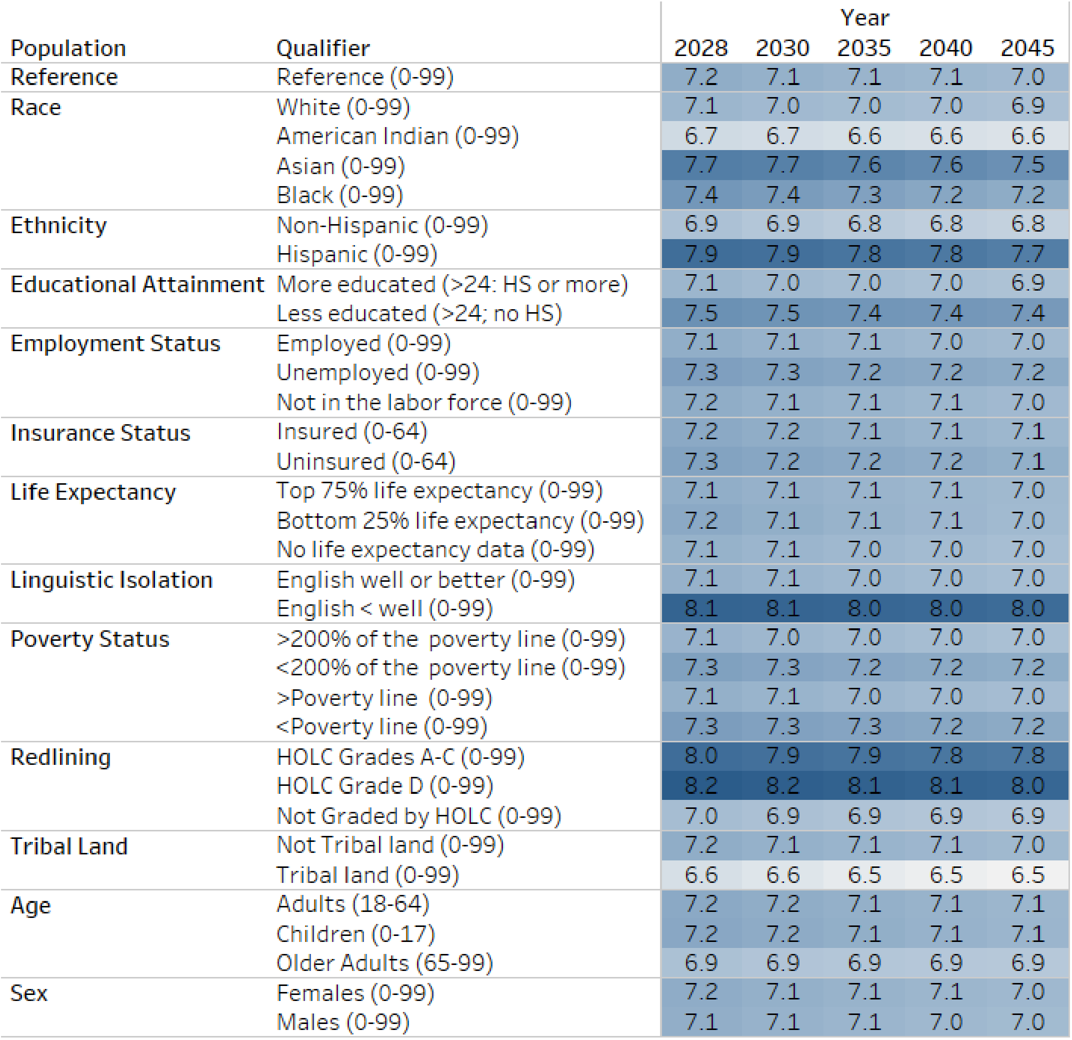
[186] https://www.federalregister.gov/documents/2023/01/27/2023-00269/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter

[187] 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 relative magnitude of differences

The national-level assessment of $PM_{2.5}$ before and after implementation of these final rulemakings suggests that while EJ exposure disparities are present in the pre-final rules scenario, EJ exposure concerns are not likely created or exacerbated by the rules for the population groups evaluated, due to the small difference in magnitudes of $PM_{2.5}$ concentration reductions across demographic groups. It is also important to note that, at the national-level the $PM_{2.5}$ concentrations before and after implementation for all five future years evaluated, the concentrations for each demographic group are below the recently revised national ambient air quality standard of 9 µg/m³.[188]



Population	Qualifier	Year 2028	2030	2035	2040	2045
Reference	Reference (0-99)	7.2	7.1	7.1	7.1	7.0
Race	White (0-99)	7.1	7.0	7.0	7.0	6.9
	American Indian (0-99)	6.7	6.7	6.6	6.6	6.6
	Asian (0-99)	7.7	7.7	7.6	7.6	7.5
	Black (0-99)	7.4	7.4	7.3	7.2	7.2
Ethnicity	Non-Hispanic (0-99)	6.9	6.9	6.8	6.8	6.8
	Hispanic (0-99)	7.9	7.9	7.8	7.8	7.7
Educational Attainment	More educated (>24: HS or more)	7.1	7.0	7.0	7.0	6.9
	Less educated (>24; no HS)	7.5	7.5	7.4	7.4	7.4
Employment Status	Employed (0-99)	7.1	7.1	7.1	7.0	7.0
	Unemployed (0-99)	7.3	7.3	7.2	7.2	7.2
	Not in the labor force (0-99)	7.2	7.1	7.1	7.1	7.0
Insurance Status	Insured (0-64)	7.2	7.2	7.1	7.1	7.1
	Uninsured (0-64)	7.3	7.2	7.2	7.2	7.1
Life Expectancy	Top 75% life expectancy (0-99)	7.1	7.1	7.1	7.1	7.0
	Bottom 25% life expectancy (0-99)	7.2	7.1	7.1	7.1	7.0
	No life expectancy data (0-99)	7.1	7.1	7.0	7.0	7.0
Linguistic Isolation	English well or better (0-99)	7.1	7.1	7.0	7.0	7.0
	English < well (0-99)	8.1	8.1	8.0	8.0	8.0
Poverty Status	>200% of the poverty line (0-99)	7.1	7.0	7.0	7.0	7.0
	<200% of the poverty line (0-99)	7.3	7.3	7.2	7.2	7.2
	>Poverty line (0-99)	7.1	7.1	7.0	7.0	7.0
	<Poverty line (0-99)	7.3	7.3	7.3	7.2	7.2
Redlining	HOLC Grades A-C (0-99)	8.0	7.9	7.9	7.8	7.8
	HOLC Grade D (0-99)	8.2	8.2	8.1	8.1	8.0
	Not Graded by HOLC (0-99)	7.0	6.9	6.9	6.9	6.9
Tribal Land	Not Tribal land (0-99)	7.2	7.1	7.1	7.1	7.0
	Tribal land (0-99)	6.6	6.6	6.5	6.5	6.5
Age	Adults (18-64)	7.2	7.2	7.1	7.1	7.1
	Children (0-17)	7.2	7.2	7.1	7.1	7.1
	Older Adults (65-99)	6.9	6.9	6.9	6.9	6.9
Sex	Females (0-99)	7.2	7.1	7.1	7.1	7.0
	Males (0-99)	7.1	7.1	7.1	7.0	7.0

Figure 6-2 Heat Map of the National Average $PM_{2.5}$ Concentrations in the Baseline Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (µg/m³)

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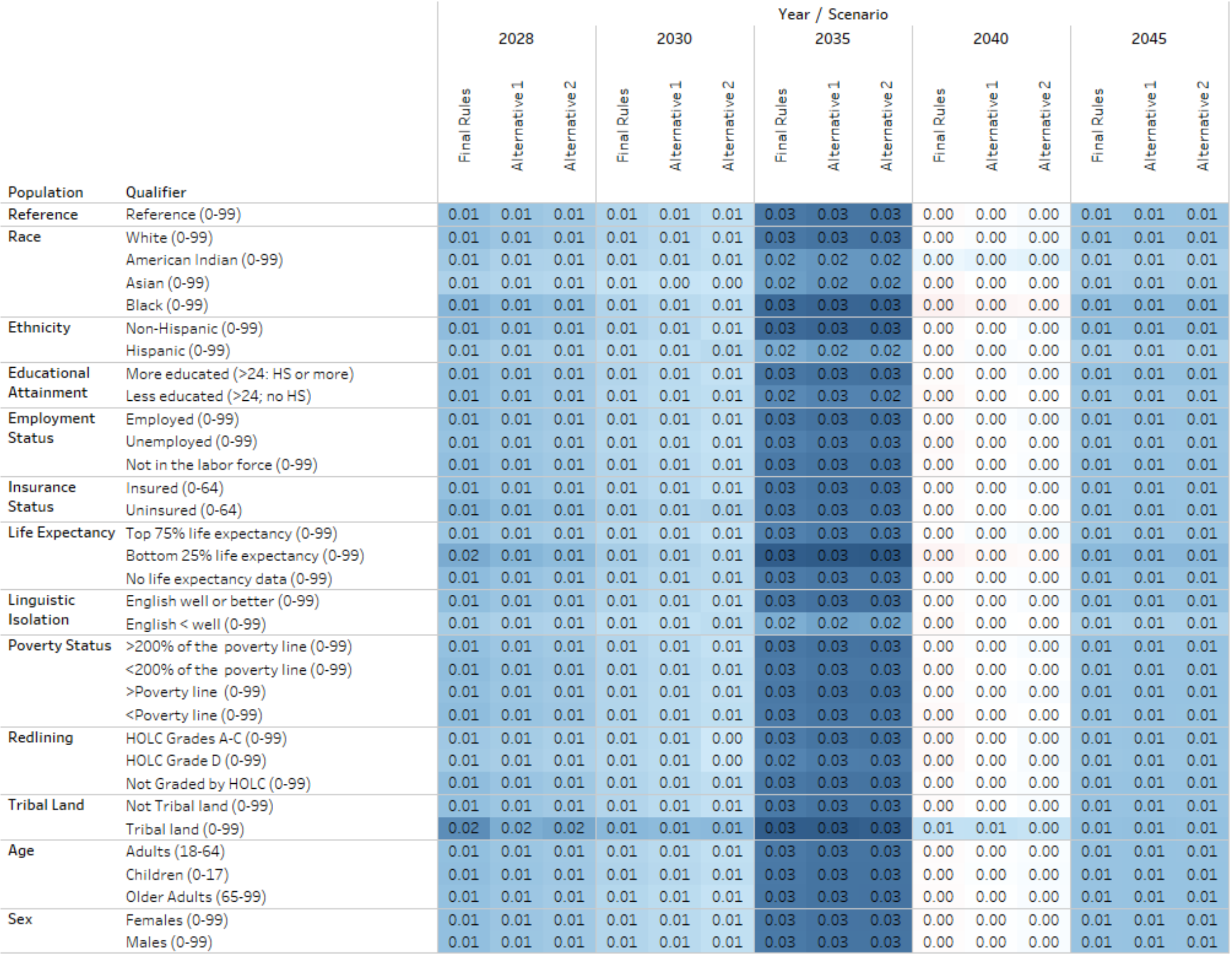
[188] See https://www.epa.gov/system/files/documents/2024-02/pm-naaqs-final-frn-pre-publication.pdf



		Year / Scenario														
		2028			2030			2035			2040			2045		
Population	Qualifier	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2
Reference	Reference (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Race	White (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	American Indian (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.00	0.00	0.00	0.01	0.01	0.01
	Asian (0-99)	0.01	0.01	0.01	0.01	0.00	0.00	0.02	0.02	0.02	0.00	0.00	0.00	0.01	0.01	0.01
	Black (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Ethnicity	Non-Hispanic (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Hispanic (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.00	0.00	0.00	0.01	0.01	0.01
Educational Attainment	More educated (>24: HS or more)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Less educated (>24; no HS)	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.02	0.00	0.00	0.00	0.01	0.01	0.01
Employment Status	Employed (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Unemployed (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Not in the labor force (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Insurance Status	Insured (0-64)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Uninsured (0-64)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Life Expectancy	Top 75% life expectancy (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Bottom 25% life expectancy (0-99)	0.02	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	No life expectancy data (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Linguistic Isolation	English well or better (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	English < well (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.00	0.00	0.00	0.01	0.01	0.01
Poverty Status	>200% of the poverty line (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	<200% of the poverty line (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	>Poverty line (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	<Poverty line (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Redlining	HOLC Grades A-C (0-99)	0.01	0.01	0.01	0.01	0.01	0.00	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	HOLC Grade D (0-99)	0.01	0.01	0.01	0.01	0.01	0.00	0.02	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Not Graded by HOLC (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Tribal Land	Not Tribal land (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Tribal land (0-99)	0.02	0.02	0.02	0.01	0.01	0.01	0.03	0.03	0.03	0.01	0.01	0.00	0.01	0.01	0.01
Age	Adults (18-64)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Children (0-17)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Older Adults (65-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
Sex	Females (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01
	Males (0-99)	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.00	0.00	0.00	0.01	0.01	0.01

Figure 6-3 Heat Map of the Reductions in National Average $PM_{2.5}$ Concentrations Due to the Three Illustrative Scenarios Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (µg/m^3)

6.5.2.2 State Aggregated Results

We also provide $PM_{2.5}$ concentration reductions by state and demographic population in 2028, 2030, 2035, 2040, and 2045 for the 48 states in the contiguous U.S., for the final rules option and each alternative regulatory option.[189] Reductions due to the policy at the state-level are shown in Figure 6-4 (reductions due to the alternative regulatory options are shown in Appendix C: Environmental Justice Analysis). In this heat map, darker blue again indicates larger $PM_{2.5}$ reductions and red indicates $PM_{2.5}$ concentration increases with states shown as columns and demographic groups as rows. In order to show all the information in a single heat

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[189] State-level averages were calculated by cross-walking the 12 km grid resolution air quality surface projections to population-weighted state-average air concentration by demographic group.

map, only colors are used to show relative $PM_{2.5}$ concentrations and only the overall reference group (i.e., everyone ages 0-99) is included. The magnitude of state-level $PM_{2.5}$ concentration changes are very similar across all three scenarios. However, due to EGU-specific estimated emission changes, the magnitude of state-level $PM_{2.5}$ concentration changes varies considerably across states. Depending on the regulatory scenario and year of analysis, average population-weighted state-level $PM_{2.5}$ concentrations are predicted to be reduced by up to 0.09 $\mu g/m^3$ (as seen in Nebraska in 2035) which is 1.3 percent of the baseline $PM_{2.5}$ concentration in 2035. Increases in $PM_{2.5}$ concentrations for state-level average populations were rare and largest in 2040 under all regulatory options in Mississippi, and only to a very small magnitude (0.02 $\mu g/m^3$) which is 0.3 percent of the baseline $PM_{2.5}$ concentration in 2040. When considering differences between demographic populations and the reference population affected by a particular policy within a given year, average $PM_{2.5}$ concentration changes at the state-level only differ from the reference population by up to 0.02 $\mu g/m^3$ which is 0.3 percent of the baseline $PM_{2.5}$ concentration in 2040.[190] While the percent changes relative to the baseline are notable, the magnitude of the changes is too small to have a discernible impact on public health outcomes. Therefore, whereas $PM_{2.5}$ exposure impacts vary by state, the small magnitude of differential impacts expected from the final rules is not likely to exacerbate or mitigate EJ concerns within individual states.

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[190] 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.

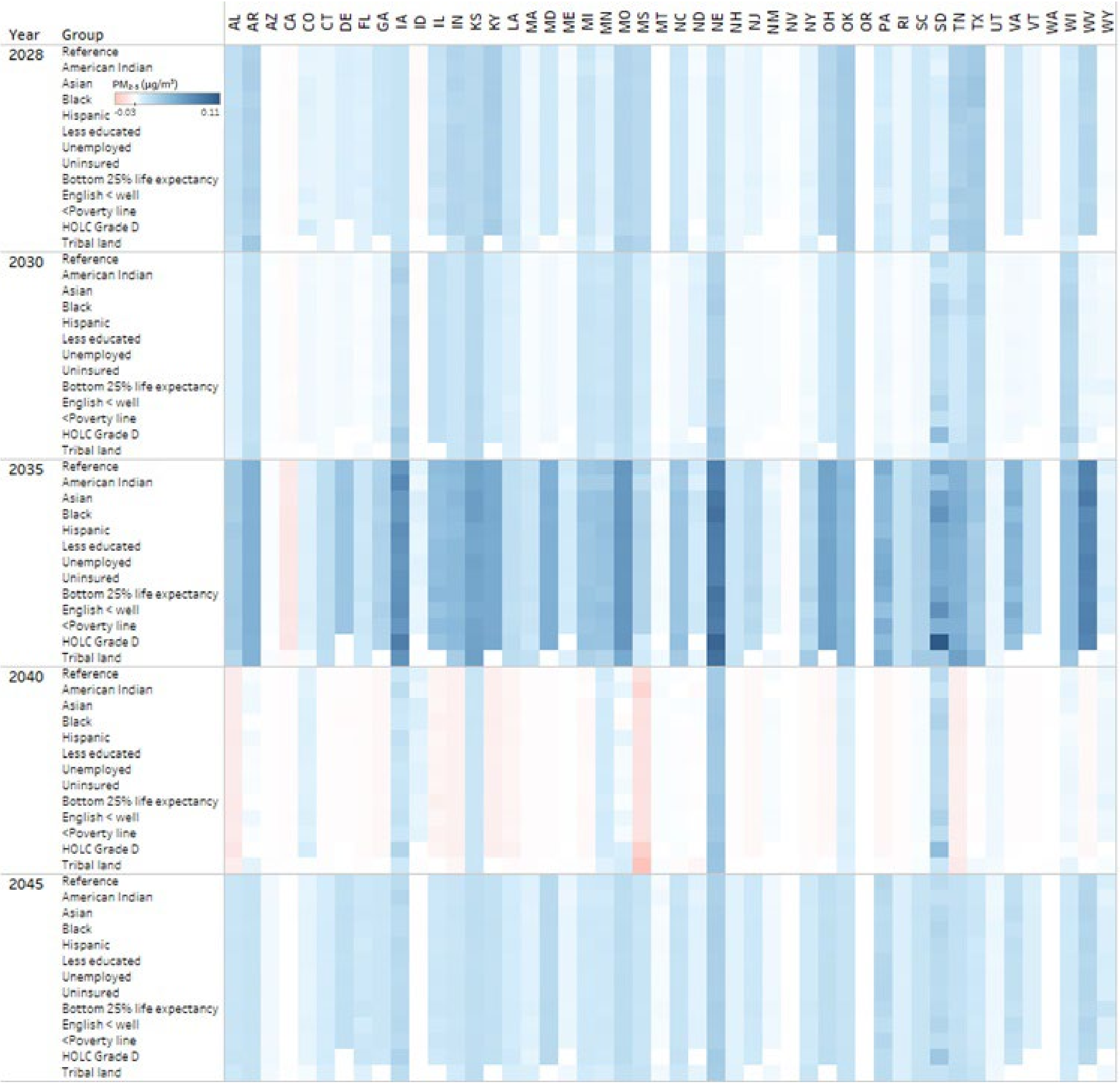

Figure 6-4 Heat Map of the State Average PM2.5 Concentration Reductions (Blue) and Increases (Red) Due to the Final Rules Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (µg/m^3) (Alternative Scenarios are shown in Appendix C)

6.5.2.3 Distributional Results

We also present the cumulative proportion of each population exposed to ascending levels of $PM_{2.5}$ concentration changes across the contiguous U.S. averaged at the county level. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanic population) 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 the contiguous U.S.) experiences similar concentration changes from EGU emission changes under the three regulatory options in 2028, 2030, 2035, 2040, and 2045. Concentration reductions due to the policy at the county-level are shown in Figure 6-5 (reductions due to the alternative regulatory options are shown in Appendix C).

This distributional EJ analysis is also subject to additional uncertainties related to more highly- resolved input parameters and additional assumptions. For example, this analysis does not explicitly account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations to $PM_{2.5}$ exposure although we have incorporated variables such as life expectancy and redlining into our EJ analyses to serve as proxies for cumulative exposures within communities that lead to possible underlying susceptibility and vulnerability. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups. As the baseline scenario is similar to that described by other RIAs (e.g., the Regulatory Impact Analysis for the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter)[191], we focus on the $PM_{2.5}$ changes due to these rulemakings. The vast majority of each demographic population are predicted to experience $PM_{2.5}$ concentration changes less than 0.06 $\mu g/m^3$ at the state-level under any of the regulatory options for all five future years analyzed. While the greatest impacts, and the greatest differential impacts across population, occur in 2035, the distributions of $PM_{2.5}$ concentration changes across population demographics are all fairly similar, and the small difference in impacts shown in the 2028, 2030, 2035, 2040, and 2045 distributional analyses of $PM_{2.5}$ reductions under the various regulatory options suggests that the regulatory options are not likely to exacerbate or mitigate EJ $PM_{2.5}$ exposure concerns for population groups evaluated.

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[191] https://www.federalregister.gov/documents/2023/01/27/2023-00269/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter

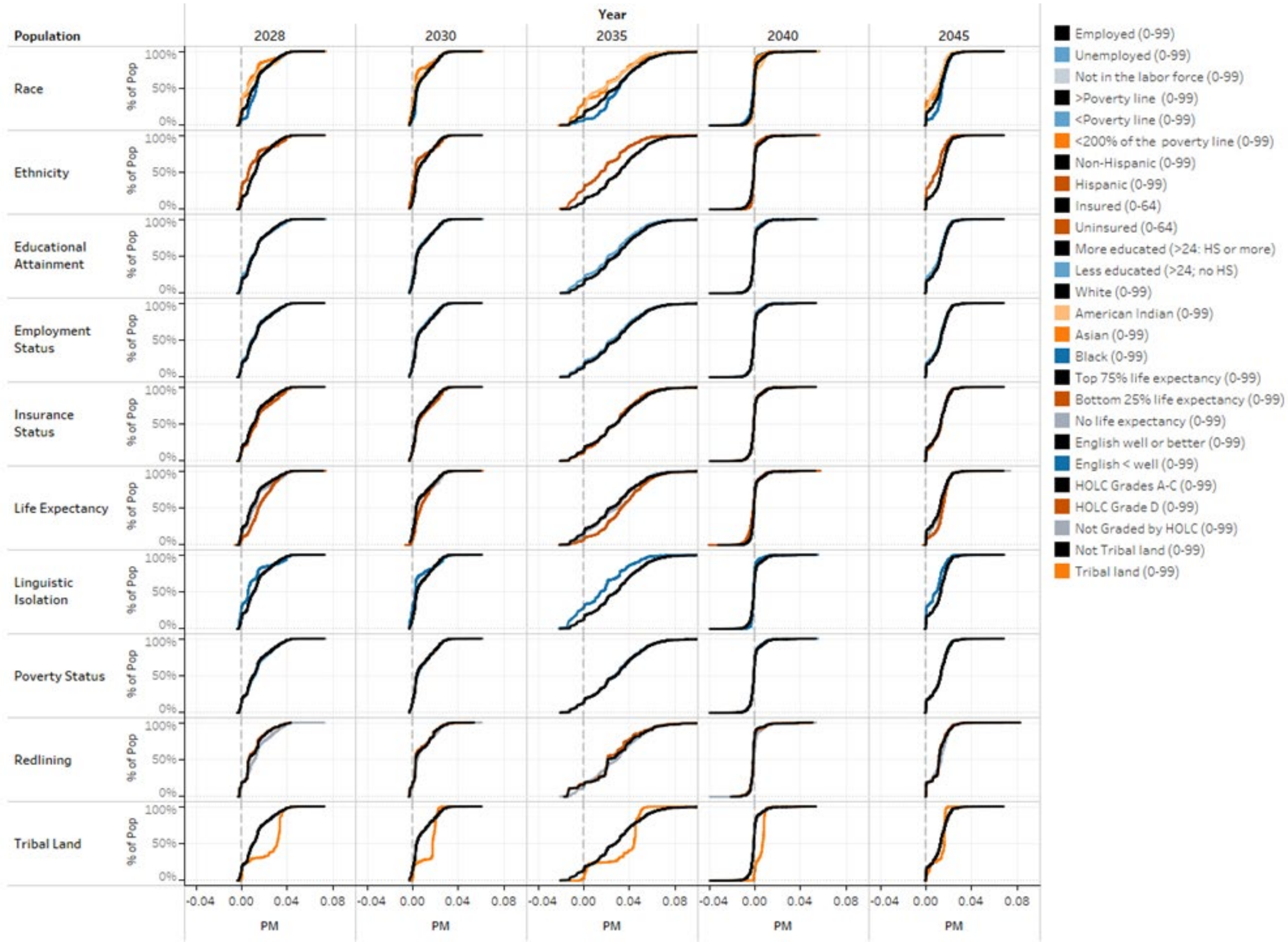

Figure 6-5 Distribution of $PM_{2.5}$ Concentration (µg/m^3) Reductions Across Populations, Future Years for the Final Rules Scenario (Alternative scenarios are shown in Appendix C)

6.5.3 Ozone EJ Exposure Analysis

To evaluate the potential for EJ concerns among communities with EJ concerns resulting from exposure to ozone under the baseline and regulatory options in these rules, we characterize the distribution of ozone exposures both prior to and following implementation of the rules, as well as under the alternative regulatory options, in 2028, 2030, 2035, 2040, and 2045.

As this analysis is based on the same ozone spatial fields as the benefits assessment (see Section 3 for a discussion of the spatial fields), it is subject to similar types of uncertainty. In addition to the small magnitude of differential ozone concentration changes associated with these final rulemakings when comparing across demographic populations, 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.

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 eight-hour average ozone concentrations (AS-MO3), consistent with the health impact functions used in the benefits assessment (Section 4). 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 potential 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 eight-hour concentrations.[192] 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 (eight-hour) exceedances of the ozone NAAQS. Relatedly, 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, 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 ozone exposure assessment.

6.5.3.1 National Aggregated Results

National average baseline ozone concentrations in ppb in 2028, 2030, 2035, 2040, and 2045 are shown in a heat map (Figure 6-6). Concentrations represent the total estimated daily eight-hour maximum ozone exposure burden averaged over the 6-month April-September ozone

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[192] Level of 70 ppb with an annual fourth-highest daily maximum eight-hour concentration, averaged over three years.

season and are colored to visualize differences more easily in average concentrations, with lighter green coloring representing smaller average concentrations and darker green coloring representing larger average concentrations. When looking across all five future years, all demographic groups will see improving ozone concentrations over time in the baseline such that the average concentration experienced by each demographic group will be less in 2030 than in 2028, less in 2035 than in 2030, and so on. When looking within each future year's baseline, populations with national average ozone concentrations higher than the reference population ordered from most to least difference were: American Indian populations, Hispanic populations, those linguistically isolated, Asian populations, those living on Tribal land, residents of HOLC Grade A-C (i.e., not redlined) census tracts, those without a high school diploma, the unemployed, those with the top 75 percent life expectancy or no life expectancy data available, and children. Average national disparities observed in the baseline of these rules are fairly consistent across the five future years and similar to those described by recent rules (e.g., the Regulatory Impact Analysis for Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard).[193]

In Figure 6-7, columns labeled "Final Rules" "Alternative 1," and "Alternative 2" provide information regarding how all three regulatory options will impact ozone concentrations across various populations.[194] All national-level ozone concentration changes of these final rulemakings across population groups, years, and regulatory options are predicted to be relatively small in absolute magnitude (i.e., <0.09 ppb) relative to the magnitude of disparities in the baseline across populations. When comparing the small changes across demographic groups, there are some disparate impacts in 2035 for Asian populations, Hispanic populations, those living on Tribal lands, and those linguistically isolated (Figure 6-7). However, in the other years and regulatory options analyzed, populations are estimated to experience similar ozone concentration reductions to that of the reference populations with the exception of the Tribal land demographic group which is estimated to experience the largest ozone reductions of any

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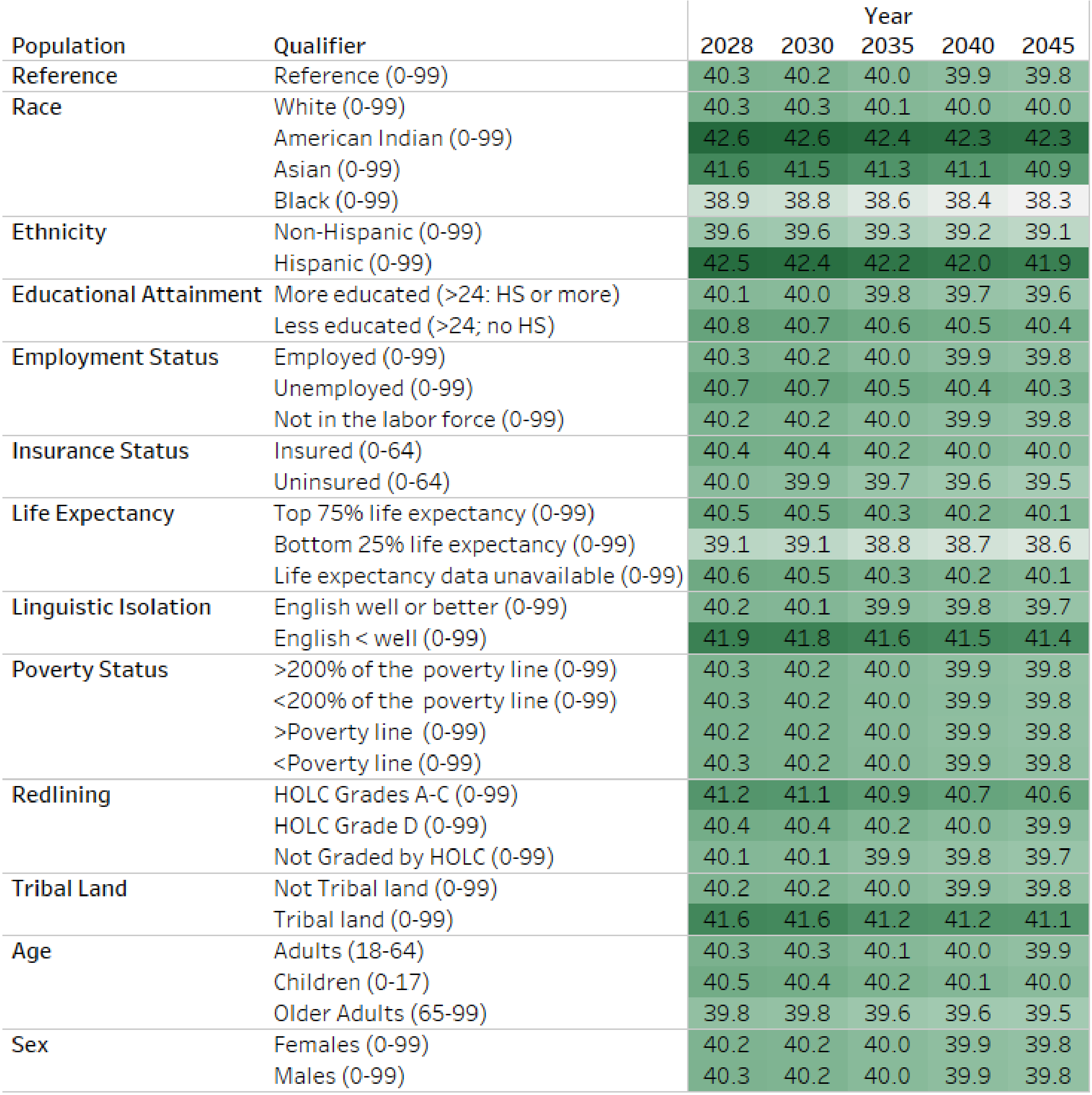
[193] https://www.federalregister.gov/documents/2023/01/27/2023-00269/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter

[194] 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 difference

demographic group/year in 2028 and 2030 (up to 0.09 ppb), followed by the largest increases in ozone of any demographic group/year in 2040 (up to 0.03 ppb).

The national-level assessment of ozone burden concentrations in the baseline and ozone exposure changes due to the regulatory options suggests that while most policy options and future years analyzed will not likely mitigate or exacerbate ozone EJ exposure disparities for the population groups evaluated, ozone EJ exposure disparities may be slightly exacerbated for some population groups analyzed in 2035 and those living on Tribal lands in 2040 as well as slightly mitigated for those living on Tribal lands in 2028 and 2030 under all regulatory options. However, the extent to which disparities may be exacerbated is likely modest across population groups, at most between 0.1 percent and 0.2 percent of baseline ozone levels. Note that while we were able to compare the annual average $PM_{2.5}$ concentrations to the newly revised NAAQS, the estimated ozone impacts in terms of annual average change are difficult to compare to the ozone NAAQS which is reported as the fourth-highest daily maximum 8-hour concentration.



		Year				
Population	Qualifier	2028	2030	2035	2040	2045
Reference	Reference (0-99)	40.3	40.2	40.0	39.9	39.8
Race	White (0-99)	40.3	40.3	40.1	40.0	40.0
	American Indian (0-99)	42.6	42.6	42.4	42.3	42.3
	Asian (0-99)	41.6	41.5	41.3	41.1	40.9
	Black (0-99)	38.9	38.8	38.6	38.4	38.3
Ethnicity	Non-Hispanic (0-99)	39.6	39.6	39.3	39.2	39.1
	Hispanic (0-99)	42.5	42.4	42.2	42.0	41.9
Educational Attainment	More educated (>24: HS or more)	40.1	40.0	39.8	39.7	39.6
	Less educated (>24; no HS)	40.8	40.7	40.6	40.5	40.4
Employment Status	Employed (0-99)	40.3	40.2	40.0	39.9	39.8
	Unemployed (0-99)	40.7	40.7	40.5	40.4	40.3
	Not in the labor force (0-99)	40.2	40.2	40.0	39.9	39.8
Insurance Status	Insured (0-64)	40.4	40.4	40.2	40.0	40.0
	Uninsured (0-64)	40.0	39.9	39.7	39.6	39.5
Life Expectancy	Top 75% life expectancy (0-99)	40.5	40.5	40.3	40.2	40.1
	Bottom 25% life expectancy (0-99)	39.1	39.1	38.8	38.7	38.6
	Life expectancy data unavailable (0-99)	40.6	40.5	40.3	40.2	40.1
Linguistic Isolation	English well or better (0-99)	40.2	40.1	39.9	39.8	39.7
	English < well (0-99)	41.9	41.8	41.6	41.5	41.4
Poverty Status	>200% of the poverty line (0-99)	40.3	40.2	40.0	39.9	39.8
	<200% of the poverty line (0-99)	40.3	40.2	40.0	39.9	39.8
	>Poverty line (0-99)	40.2	40.2	40.0	39.9	39.8
	<Poverty line (0-99)	40.3	40.2	40.0	39.9	39.8
Redlining	HOLC Grades A-C (0-99)	41.2	41.1	40.9	40.7	40.6
	HOLC Grade D (0-99)	40.4	40.4	40.2	40.0	39.9
	Not Graded by HOLC (0-99)	40.1	40.1	39.9	39.8	39.7
Tribal Land	Not Tribal land (0-99)	40.2	40.2	40.0	39.9	39.8
	Tribal land (0-99)	41.6	41.6	41.2	41.2	41.1
Age	Adults (18-64)	40.3	40.3	40.1	40.0	39.9
	Children (0-17)	40.5	40.4	40.2	40.1	40.0
	Older Adults (65-99)	39.8	39.8	39.6	39.6	39.5
Sex	Females (0-99)	40.2	40.2	40.0	39.9	39.8
	Males (0-99)	40.3	40.2	40.0	39.9	39.8

Figure 6-6 Heat Map of the National Average Ozone Concentrations in the Baseline Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (ppb)

		Year / Scenario 2028			2030			2035			2040			2045		
Population	Qualifier	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2	Final Rules	Alternative 1	Alternative 2
Reference	Reference (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
Race	White (0-99)	0.03	0.02	0.02	0.03	0.03	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	American Indian (0-99)	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.03	0.02	0.00	0.00	0.00	0.03	0.03	0.03
	Asian (0-99)	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.03
	Black (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.04	-0.01	0.00	-0.01	0.04	0.04	0.04
Ethnicity	Non-Hispanic (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.05	0.05	0.05	0.00	0.00	0.00	0.04	0.04	0.04
	Hispanic (0-99)	0.03	0.02	0.02	0.03	0.03	0.02	0.00	0.01	0.00	0.00	0.00	-0.01	0.03	0.03	0.03
Educational Atta..	More educated (>24: HS or more)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Less educated (>24; no HS)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.00	0.00	-0.01	0.03	0.03	0.03
Employment Status	Employed (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Unemployed (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
	Not in the labor force (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
Insurance Status	Insured (0-64)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Uninsured (0-64)	0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.04	0.03	0.00	0.00	-0.01	0.04	0.04	0.04
Life Expectancy	Top 75% life expectancy (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
	Bottom 25% life expectancy (0-99)	0.03	0.03	0.03	0.03	0.03	0.02	0.05	0.05	0.05	-0.01	0.00	-0.01	0.05	0.05	0.05
	Life expectancy data unavailable (0-99)	0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
Linguistic Isolati..	English well or better (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	English < well (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	-0.01	0.01	0.00	0.00	0.00	0.00	0.03	0.03	0.03
Poverty Status	>200% of the poverty line (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	<200% of the poverty line (0-99)	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
	>Poverty line (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	<Poverty line (0-99)	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03	0.00	0.00	0.00	0.04	0.04	0.04
Redlining	HOLC Grades A-C (0-99)	0.01	0.01	0.01	0.02	0.03	0.01	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	HOLC Grade D (0-99)	0.01	0.01	0.01	0.02	0.03	0.01	0.03	0.04	0.03	-0.01	0.00	0.00	0.04	0.04	0.04
	Not Graded by HOLC (0-99)	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
Tribal Land	Not Tribal land (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Tribal land (0-99)	0.09	0.08	0.07	0.08	0.07	0.06	0.02	0.03	0.01	-0.02	-0.02	-0.03	0.03	0.03	0.03
Age	Adults (18-64)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Children (0-17)	0.03	0.02	0.02	0.03	0.03	0.02	0.03	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Older Adults (65-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
Sex	Females (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04
	Males (0-99)	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.04	0.00	0.00	0.00	0.04	0.04	0.04

Figure 6-7 Heat Map of Reductions (Green) and Increases (Red) in National Average Ozone Concentrations Due to the Three Regulatory Options Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (ppb)

6.5.3.2 State Aggregated Results

We also provide ozone concentration reductions by state and demographic population in 2028, 2030, 2035, 2040, and 2045 for the 48 states in the contiguous U.S., for the final rules and alternative 1 scenarios (Figure 6-8). Reductions due to the final rules at the state-level are shown in Figure 6-8 (reductions due to the alternative regulatory options are shown in Appendix C). In this heat map, darker green again indicates larger ozone reductions, with demographic groups shown as rows and each state as a column. On average, the state-specific reference populations are projected to experience reductions in ozone concentrations by up to 0.55 ppb (observed for Black populations in Nebraska under the "Final Rules Scenario" and "Alternative 1 Scenario" in 2035), a 1.4 percent change relative to the baseline ozone level in 2035. Ozone increases are shown in red and are of smaller magnitude than that of predicted ozone decreases. The maximum ozone increases are observed with the "Final Rules" policy option in 2035 with a maximum state-level population-weighted average of 0.12 ppb experienced by Hispanic populations in

California, a 0.3 percent change relative to the baseline ozone level in 2035. This is notable given that California's central valley and LA basin have higher baseline ozone concentrations than other parts of the country in all modeled years, and these regions are home to many disadvantaged communities.[195] Importantly, Figure 6-8 shows that demographic groups within most states are predicted to experience very similar exposure impacts as the state reference populations, with a few potential exceptions (e.g., Iowa, Nebraska, South Dakota, and West Virginia in 2035, 2040, and 2045). When comparing exposure impacts across demographic groups within states, most states display similar impacts across demographic groups in 2028, 2035, 2040, and 2045. However, some populations with higher exposures have larger differences in reductions between groups. For example, within several states, the largest difference in reductions between a population and the reference population is 0.11 ppb. Therefore, the state-level assessment of ozone exposure changes due to the regulatory options suggests that while most policy options and future years analyzed will not likely mitigate or exacerbate ozone EJ exposure disparities for the population groups evaluated in 2028, 2035, 2040, and 2045, ozone EJ exposure disparities at the state level may be either mitigated or exacerbated for some population groups analyzed in 2035, 2040, and 2045 under the various regulatory options. However, the extent to which disparities may be exacerbated or mitigated is likely modest, due to the small magnitude of the ozone concentration changes relative to the magnitude of baseline ozone exposure disparities (between 0.3 percent to 1.4 percent of baseline ozone levels).

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[195] See Tables B8-12 in the Appendix for more information about the modeled air quality in California and the California Air Resources Board's CalEnviroScreen website about more information regarding demographic groups living in affected areas with higher ozone concentrations (https://experience.arcgis.com/experience/1c21c53da8de48f1b946f3402fbae55c/page/SB-535-Disadvantaged-Communities/)

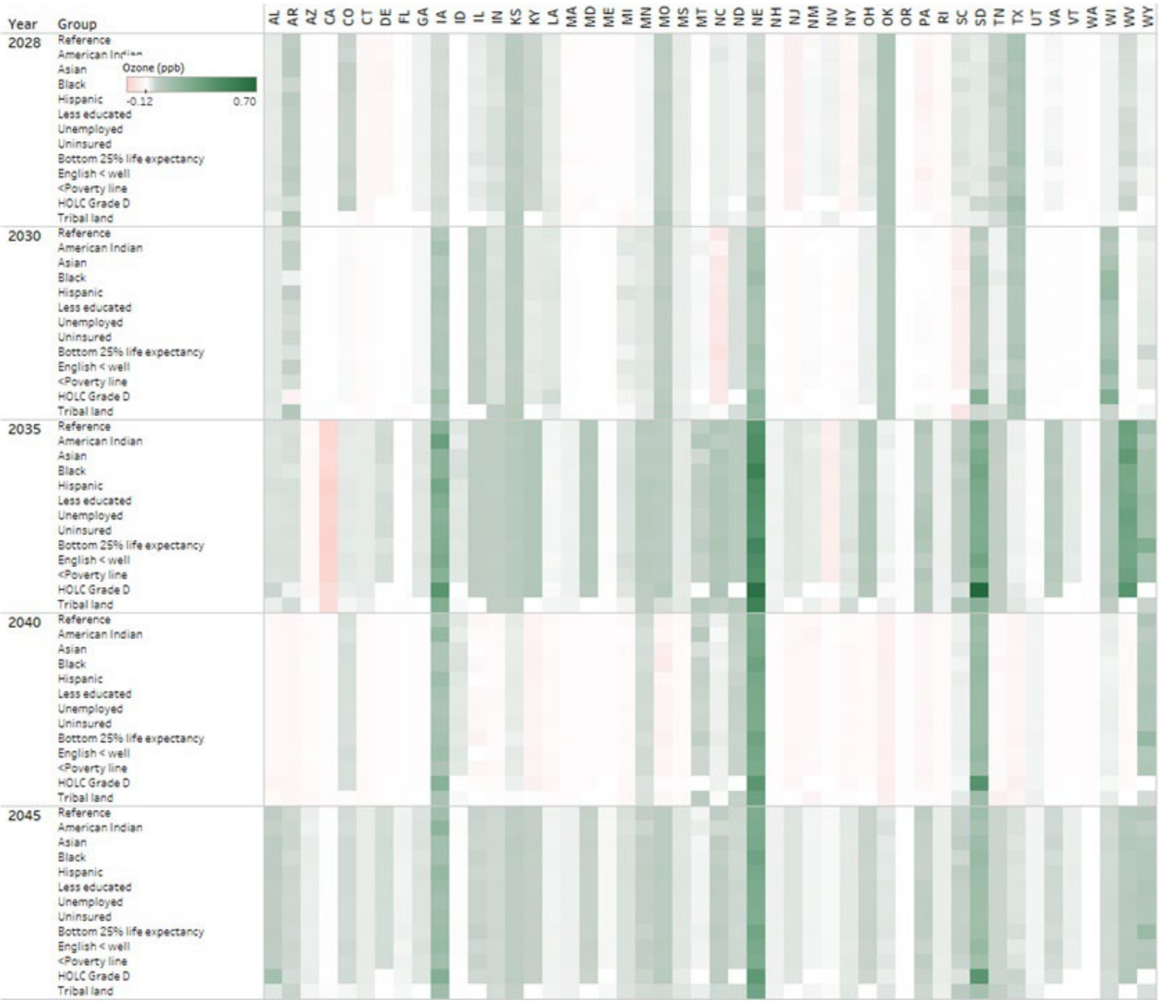

Figure 6-8 Heat Map of the State Average Ozone Concentrations Reductions (Green) and Increases (Red) Due to the Final Rules Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (ppb) (Alternative Scenarios are shown in Appendix C)

6.5.3.3 Distributional Results

We also present cumulative proportion of each population exposed to ascending levels of ozone concentration changes across the contiguous U.S. Results allow evaluation of what percentage of each subpopulation (e.g., Hispanic population) in the contiguous U.S. experience what change in ozone 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 changes under the three regulatory options in 2028, 2030, 2035, 2040, and 2045.

This distributional EJ analysis is also subject to additional uncertainties related to more highly resolved input parameters and additional assumptions. For example, this analysis does not explicitly account for potential differences in underlying susceptibility, vulnerability, or risk factors across populations expected to experience post-policy ozone exposure changes although we have incorporated variables such as life expectancy and redlining into our demographic to serve as proxies for cumulative exposures within communities that lead to possible underlying susceptibility and vulnerability. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups.

As the baseline scenario is similar to that described by other RIAs (the Regulatory Impact Analysis for Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard)[196], we focus on the ozone changes due to these rulemakings. Distributions of 12 km gridded ozone concentration changes from EGU control strategies of affected facilities under the final rules scenario analyzed in these final rulemakings are shown in Figure 6-9 (alternative regulatory options are shown in Appendix C). When comparing distributional exposure impacts across demographic groups, similar impacts are predicted to occur across demographic groups in 2028, 2030, 2040, and 2045. However, certain groups, specifically Asian populations, Hispanic populations, those linguistically isolated, and those living on Tribal land may experience smaller ozone exposure reductions across the population distributions in 2035, as compared to the overall reference distribution. Additionally, those living on Tribal lands may experience small ozone exposure increases across the population distributions in 2040 as well as larger ozone exposure reductions across the population distributions in 2028 and 2030. Therefore, the distributional assessment of ozone exposure changes due to the regulatory options suggests that while most regulatory options and future years analyzed will not likely mitigate or exacerbate ozone EJ exposure disparities for the population groups evaluated in 2028, 2035, 2040, and 2045, distributional ozone EJ exposure disparities may be slightly exacerbated for some population groups analyzed in 2035 and those living on Tribal lands in 2040 as well as slightly mitigated for those living on Tribal lands in 2028 and 2030 under all regulatory options. However, the extent to which disparities may be exacerbated is likely modest, due to the small magnitude of the ozone concentration changes (will all changes between 0.3 to 1.4 percent of baseline ozone levels).

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[196] https://www.federalregister.gov/documents/2023/01/27/2023-00269/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter

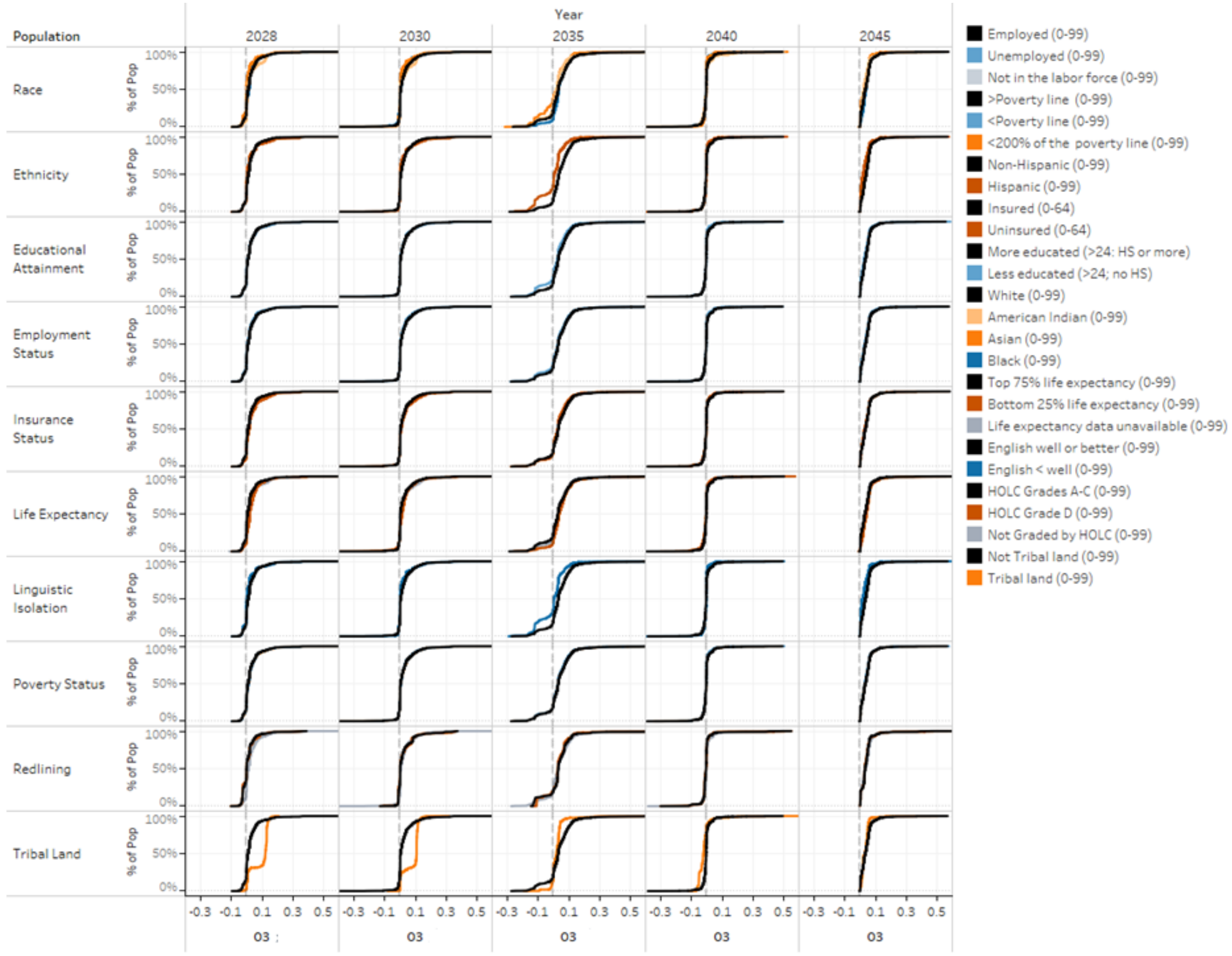

Figure 6-9 Distributions of Ozone Concentration Changes (ppb) Across Populations, Future Years for the Final Rules Scenario (Alternative Scenarios are shown in Appendix C)

6.6 Qualitative Discussion of EJ $PM_{2.5}$ Health Impacts

While the potential for EJ concerns related to $PM_{2.5}$ health outcomes (i.e., premature mortality) among populations potentially at increased risk of or to $PM_{2.5}$ exposures have been evaluated previously (U.S. EPA, 2022a), EJ health impacts of $PM_{2.5}$ exposures were not quantitatively evaluated here, due to resource limitations and the lack of substantial differential EJ impacts of the final rulemaking (Section 3.8).

While quantitative impacts are not analyzed, we can qualitatively speak to the expected $PM_{2.5}$-attributable mortality EJ impacts of these final rules, based on prior quantitative results and the $PM_{2.5}$ EJ exposure results provided here. For context, the PM ISA and PM ISA

Supplement provided evidence that there are consistent racial and ethnic disparities in $PM_{2.5}$ exposure across the U.S., particularly for Black populations, as compared to non-Hispanic White populations. Additionally, some studies provided evidence of increased $PM_{2.5}$-related mortality and other health effects from long-term exposure to $PM_{2.5}$ among Black populations. Taken together, the 2019 PM ISA concluded that the evidence was adequate to conclude that race and ethnicity modify $PM_{2.5}$-related risk, and that non-White individuals, particularly Black individuals, are at increased risk for $PM_{2.5}$-related health effects, in part due to disparities in exposure ISA (U.S. EPA, 2019, 2022b).

Qualitatively, as the $PM_{2.5}$ exposure changes are fairly consistent across demographic populations, differential impacts are expected to reflect the epidemiologic hazard ratios. This suggests that $PM_{2.5}$ improvements would be most beneficial for Black populations, followed by Hispanic and Asian populations. Conversely, worsening air quality would be disproportionately harmful to the same groups in the same hierarchy.

6.7 Qualitative Discussion of New Source EJ Impacts

EJ impacts of new sources subject to 111(b) are highly uncertain as the location of new sources is unknown. Therefore, we do not make predictions regarding potential EJ impacts from new sources. However, the regulatory options do account for emissions changes at existing facilities that are expected to result from the 111(b) policy.

6.8 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. 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.

For these final rules, we quantitatively evaluate the proximity of affected facilities populations of potential EJ concern (Section 4) and the potential for disproportionate pre- and post-policy $PM_{2.5}$ and ozone exposures and exposure changes across different demographic groups (Section 5). Each of these analyses 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, the proximity analysis of the full population of potentially affected units greater than 25 MW (114 facilities) indicated that the demographic percentages of the population within 5 km and 10 km of the facilities are relatively similar to the national averages with the exception of the American Indian population (1 percent and 0.8 percent, respectively) that is higher than the national average (0.6 percent). This higher percentage is driven mostly by 7 facilities that have an American Indian percentage within a 5 km and 10 km radius that ranges from 10 percent to just above 40 percent which is substantially above the national average (0.6 percent). The population living below the federal poverty line (14 percent for both distances) as well as the population living below 2x the federal poverty level (34 percent and 33 percent, respectively) that are both higher than the national averages (13 percent and 29 percent, respectively). The proximity analysis of the 23 plants with known retirement plans from 2033 to 2040, (a subset of the total 114 plants) found that the percentages of the population within 5 km and 10 km that is below the poverty line (14 percent both distances) and below 2x the federal poverty line (33 percent and 31 percent, respectively) are both higher than the national average percentages (13 percent and 29 percent, respectively). The proximity analysis for the 94 plants without known retirement plans before 2040, (a subset of the total 114 units) shows demographics similar to the total 114 facilities' proximity analysis.

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 these final rules as well as a snapshot of air pollution concentrations in several near future years.

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 5). Certain populations, such as those who are residents of HOLC Grade D (i.e., redlined) census tracts, those linguistically isolated, residents of HOLC Grade A-C (i.e., not redlined) census tracts, Hispanic populations, Asian populations, and those without a high school diploma may experience disproportionately higher $PM_{2.5}$ and ozone concentrations than the reference group. Black populations may experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and populations that are American Indian, living on Tribal land, residents of HOLC Grade D (i.e., redlined) census tracts, the unemployed, those with the top 75 percent life expectancy or no life expectancy data available, and children 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 the post-policy options of these final rulemakings are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance regarding ozone and $PM_{2.5}$ exposure changes. $PM_{2.5}$ and ozone exposure analyses show that the final rules will result in modest but widespread reductions in $PM_{2.5}$ and ozone concentrations, although some limited areas may experience small increases in ozone concentrations relative to forecasted conditions without the rule. We infer that baseline disparities in ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of any of the regulatory options under consideration due to the small magnitude of the concentration changes associated with these rulemakings across demographic populations, relative to baseline burden disparities (with the largest changes being only 1.4 percent of baseline concentrations) (EJ question 2). Also, due to the very small differences in the distributional analyses of post-policy exposure impacts across demographic populations, we do not find evidence that disparities in populations with potential EJ concerns will be exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures in 2028, 2030, 2040, and 2045. However, in 2035, Asian populations, Hispanic populations, those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities (up to 0.05 ppb different than the reference group) at the national level under all regulatory options. Additionally, those living on Tribal lands in 2040 may experience a slight exacerbation of ozone exposure disparities in 2040 (up to 0.03 ppb different than the reference group) as well as a slight mitigation of ozone exposure disparities in 2028 and 2030 (up to 0.07 ppb different than the reference group) (EJ question 3). At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups analyzed in 2035, also to a small degree (up to 0.12 ppb different than the reference group).

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 these final rulemakings (EJ question 2). This EJ assessment also suggests that this action is unlikely to mitigate or exacerbate $PM_{2.5}$ exposures disparities across populations of EJ concern analyzed. Regarding ozone exposures, while most snapshot years for the regulatory options analyzed will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated, ozone exposure disparities may be slightly exacerbated for some population groups analyzed in 2035, slightly exacerbated for those living on Tribal lands in 2040, and slightly mitigated for those living on Tribal lands in 2028 and 2030 under all regulatory options. However, the extent to which disparities may be exacerbated or mitigated is likely modest, due to the small magnitude of the ozone concentration changes relative to baseline disparities across populations (EJ question 3). Importantly, the action described in these final rules is expected to lower $PM_{2.5}$ and ozone in many areas, and thus mitigate some pre-existing health risks of air pollution across all populations evaluated.

6.9 References

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7 COMPARISON OF BENEFITS AND COSTS

7.1 Introduction

This section presents the estimates of the climate benefits, health benefits, compliance costs, and net benefits associated with the illustrative scenarios analyzed in this RIA. There are potential benefits and costs that may result from the final rules that have not been quantified or monetized. Due to data and modeling limitations, there are still many categories of climate impacts and associated damages that are not reflected yet in the monetized climate benefits from reducing CO2 emissions. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions (e.g., ocean acidification). Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 greenhouse gases and benefits from reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury), as well as ecosystem effects and visibility impairment. Additionally, there may be health, ecological, and productivity damages associated with water effluent and intake from coal generation that will be avoided by these final rules.

The compliance costs reported in this Section are not social costs; instead, we use compliance costs as a proxy for social costs. Economy-wide social costs are separately estimated and discussed in Section 5.2, but those estimates are not applied in this section. Therefore, in this section, we do not account for changes in costs and benefits due to changes in economic welfare in the broader economy arising from shifts in production and consumption that may be induced by the final requirements. Furthermore, costs and benefits due to interactions with pre-existing market distortions outside the electricity sector are omitted, as are social costs that may be associated with the net change in power sector subsidies under the final rules. Additional limitations of the analysis and sources of uncertainty are described throughout the RIA and summarized in the executive summary.

7.2 Methods

EPA calculated the PV of costs, benefits, and net benefits for the years 2024 through 2047, using the discount rates of two percent, three percent, and seven percent from the perspective of 2024. All dollars are in 2019 dollars. In order to implement the OMB Circular A-4 requirement for fulfilling E.O. 12866, we assess two scenarios representing alternative sets of requirements.

This calculation of a PV requires an annual stream of values for each year of the 2024 to 2047 timeframe. All cost and benefit analysis begins in 2028, except MR&R costs which are estimated to begin in 2024. EPA used IPM to estimate cost and emission changes for the projection years 2028, 2030, 2035, 2040 and 2045. The final rules have requirements that come into effect in different years, and the snapshot years approximate the different rule requirements over the timeframe of analysis in this RIA. For details on how the three illustrative scenarios reflect the requirements of the rules, see Section 3.2.

In the IPM modeling for this RIA, the 2028 projection year is representative of 2028 and 2029, the 2030 projection year is representative of 2030 and 2031, the 2035 projection year is representative of 2032 to 2037, the 2040 projection year is representative of 2038 to 2041, and the 2045 projection year is representative of 2042 through 2047. Estimates of costs and emission changes in other years are determined from the mapping of projection years to the calendar years that they represent. Consequently, the cost and emission estimates from IPM in each projection year are applied to the years which it represents.

Climate benefits estimates are based on these projection year emission estimates and also account for year-specific SC-CO_2 values. Health benefits are based on projection year emission estimates and also account for year-specific variables that influence the size and distribution of the benefits. These variables include population growth, income growth, and the baseline rate of death.

7.3 Results

Table 7-1 through Table 7-4 present the estimates of the projected compliance costs, climate benefits, health benefits, and net benefits across the three illustrative scenarios for the snapshot years 2028, 2030, 2035, 2040 and 2045, respectively. The comparison of benefits and costs in PV and EAV terms for the final rules can be found in Table 7-6 for the illustrative final rules scenario; Table 7-7 presents the results for the alternative 1 illustrative scenario; and Table 7-8 presents results for the alternative 2 illustrative scenario. Estimates in the tables are presented as rounded values. In this net benefits analysis, climate benefits are discounted using a two percent discount rate only.[197] Therefore, in Table 7-6 through Table 7-8, the net benefits estimates under all discount rates reflect this two percent discounting of climate benefits.

As discussed in Section 4 of this RIA, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the final rule. In particular, the monetized climate benefits are incomplete and an underestimate as explained in Section 4.2. In addition, important health, welfare, and water quality benefits anticipated under these final rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the final rules to have greater benefits than the tables in this section reflect. Simultaneously, the estimates of compliance costs used in the net benefits analysis may provide an incomplete characterization of the true costs of the rule. The balance of unquantified benefits and costs is ambiguous but is unlikely to change the result that the benefits of the final rules exceed the costs by billions of dollars annually.

We also note that the RIA follows EPA's historical practice of using a technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. In Section 5.2 of this RIA, EPA has also included an economy-wide analysis that considers additional facets of the economic response to the final rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies. The social cost estimates in the economy-wide analysis discussed in Section 5.2 are still far below the projected benefits of the final rules.

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[197] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with EPA's updated estimates of the SC-CO_2. OMB has long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. Because the SC-CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-CO_2. See Section 4.2 for more discussion.

Table 7-1 Net Benefits of the Three Illustrative Scenarios in 2028 (billion 2019 dollars)[a,b]

	Final Rules			Alternative 1			Alternative 2		
Climate Benefits [c]		8.4			7.9			7.1	
$PM_{2.5}$ and O_3-related Health Benefits [d]	2.6	and	5.8	2.3	and	5.2	2.1	and	4.8
Total Benefits	11	and	14	10	and	13	9.2	and	12
Compliance Costs [e]		-1.3			-1.1			-1.1	
Net Benefits	12	and	15	11	and	14	10	and	13

Non-Monetized Benefits[f]
Benefits from reductions in HAP emissions
Benefits from improved water quality and availability
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP
Reductions in exposure to ambient NO_2 and SO_2
Improved visibility (reduced haze) from $PM_{2.5}$ reductions

[a] We focus results to provide a snapshot of costs and benefits in 2028, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[d] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The two columns for each scenario of the health benefits represent different studies to estimate premature deaths among adults. The health benefits are associated with several point estimates and are presented at a real discount rate of 2 percent.

[e] The discount rate in IPM is 3.76 percent, as described in Section 3.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-2 Net Benefits of the Three Illustrative Scenarios in 2030 (billion 2019 dollars)[a,b]

	Final Rules			Alternative 1			Alternative 2		
Climate Benefits [c]		11			11			6.2	
$PM_{2.5}$ and O_3-related Health Benefits [d]	1.8	and	4.0	1.5	and	3.6	1.2	and	2.8
Total Benefits	13	and	15	12	and	14	7.4	and	9.0
Compliance Costs [e]		-0.22			-0.046			-0.72	
Net Benefits	13	and	16	13	and	15	8.1	and	9.7
Non-Monetized Benefits [f]									
Benefits from reductions in HAP emissions									
Benefits from improved water quality and availability									
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP									
Reductions in exposure to ambient NO_2 and SO_2									
Improved visibility (reduced haze) from $PM_{2.5}$ reductions									

[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] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[d] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 2 percent.

[e] The discount rate in IPM is 3.76 percent, as described in Section 3.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-3 Net Benefits of the Three Illustrative Scenarios in 2035 (billion 2019 dollars)[a,b]

	Final Rules			Alternative 1			Alternative 2		
Climate Benefits [c]		30			30			30	
PM$_{2.5}$ and O$_3$-related Health Benefits [d]	6.9	and	15	7.1	and	15	7.1	and	15
Total Benefits	37	and	45	37	and	46	37	and	45
Compliance Costs [e]		1.3			1.2			1.2	
Net Benefits	36	and	44	36	and	44	36	and	44

Non-Monetized Benefits [f]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from PM$_{2.5}$ reductions

[a] We focus results to provide a snapshot of costs and benefits in 2035, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[d] Monetized benefits include those related to public health associated with reductions in PM$_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 2 percent.

[e] The discount rate in IPM is 3.76 percent, as described in Section 3.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-4 Net Benefits of the Three Illustrative Scenarios in 2040 (billion 2019 dollars)[a,b]

	Final Rules			Alternative 1			Alternative 2		
Climate Benefits [c]		14			14			14	
$PM_{2.5}$ and O_3-related Health Benefits [d]	-0.14	and	-0.35	0.012	and	0.00043	0.091	and	0.087
Total Benefits	14	and	14	14	and	14	14	and	14
Compliance Costs [e]		0.59			0.64			0.60	
Net Benefits	13	and	13	13	and	13	13	and	13

Non-Monetized Benefits [f]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from $PM_{2.5}$ reductions

[a] We focus results to provide a snapshot of costs and benefits in 2040, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[d] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 2 percent.

[e] The discount rate in IPM is 3.76 percent, as described in Section 3.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-5 Net Benefits of the Three Illustrative Scenarios in 2045 (billion 2019 dollars)[a,b]

	Final Rules			Alternative 1			Alternative 2		
Climate Benefits [c]		12			11			11	
$PM_{2.5}$ and O_3-related Health Benefits [d]	3.6	and	8.2	3.7	and	8.2	3.7	and	8.2
Total Benefits	16	and	20	15	and	20	15	and	20
Compliance Costs [e]		3.3			3.3			3.6	
Net Benefits	12	and	17	12	and	16	11	and	16
Non-Monetized Benefits [f]									
Benefits from reductions in HAP emissions									
Benefits from improved water quality and availability									
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP									
Reductions in exposure to ambient NO_2 and SO_2									
Improved visibility (reduced haze) from $PM_{2.5}$ reductions									

[a] We focus results to provide a snapshot of costs and benefits in 2045, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[d] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 2 percent.

[e] The discount rate in IPM is 3.76 percent, as described in Section 3.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-6 Net Benefits of the Final Rules Illustrative Scenario for 2024 to 2047 (billion 2019 dollars) [a]

	Climate Benefits[b]	PM$_{2.5}$ and O_3-related Health Benefits[c]			Compliance Costs[d]	Net Benefits[e]		
	2%	2%	3%	7%		2%	3%	7%
2024	-	-	-	-	0.011	-0.011	-0.011	-0.011
2025	-	-	-	-	0.011	-0.011	-0.011	-0.011
2026	-	-	-	-	0.011	-0.011	-0.011	-0.011
2027	-	-	-	-	0.000070	-0.000070	-0.000070	-0.000070
2028	8.4	5.8	5.6	5.0	-1.3	15	15	15
2029	8.5	5.9	5.8	5.1	-1.3	16	16	15
2030	11	4.0	3.9	3.5	-0.22	16	15	15
2031	12	4.1	4.0	3.5	-0.22	16	16	15
2032	29	14	13	12	1.3	41	41	39
2033	29	14	14	12	1.3	42	42	40
2034	30	14	14	12	1.3	43	43	41
2035	30	15	14	13	1.3	44	43	42
2036	31	15	15	13	1.3	44	44	42
2037	31	15	15	13	1.3	45	45	43
2038	14	-0.34	-0.33	-0.29	0.59	13	13	13
2039	14	-0.34	-0.33	-0.30	0.59	13	13	13
2040	14	-0.35	-0.34	-0.30	0.59	13	13	13
2041	14	-0.36	-0.35	-0.31	0.59	13	13	13
2042	11	7.9	7.7	6.8	3.3	16	16	15
2043	12	8.0	7.7	6.9	3.3	16	16	15
2044	12	8.1	7.8	6.9	3.3	16	16	15
2045	12	8.2	7.9	7.0	3.3	17	16	16
2046	12	8.3	8.0	7.1	3.3	17	17	16
2047	12	8.3	8.1	7.2	3.3	17	17	16

	Climate Benefits[b]	PM$_{2.5}$ and O_3-related Health Benefits[c]			Compliance Costs[d]			Net Benefits[e]		
	Discount Rate									
	2%	2%	3%	7%	2%	3%	7%	2%	3%	7%
PV	270	120	100	59	19	15	7.5	370	360	320
EAV	14	6.3	6.1	5.2	0.98	0.91	0.65	20	19	19

Non-Monetized Benefits[f]
Benefits from reductions in HAP emissions
Benefits from improved water quality and availability
Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP
Reductions in exposure to ambient NO_2 and SO_2
Improved visibility (reduced haze) from PM$_{2.5}$ reductions

[a] Annual values from 2024 to 2047 are not discounted. PV and EAV values discounted to 2024. Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-3 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[c] The health benefits estimates use the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[d] The discount rate in IPM is 3.76 percent, as described in Section 3.

[e] In this net benefits analysis, health benefits and costs are discounted at the rates shown in the table (i.e., two percent, three percent, and seven percent). Climate benefits are discounted using a two percent discount rate only in this net benefits analysis.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-7 Net Benefits of the Alternative 1 Illustrative Scenario for 2024 to 2047 (billion 2019 dollars) [a]

	Climate Benefits[b]	$PM_{2.5}$ and O_3-related Health Benefits[c]			Compliance Costs[d]	Net Benefits[e]		
	2%	2%	3%	7%		2%	3%	7%
2024	-	-	-	-	0.011	-0.011	-0.011	-0.011
2025	-	-	-	-	0.011	-0.011	-0.011	-0.011
2026	-	-	-	-	0.011	-0.011	-0.011	-0.011
2027	-	-	-	-	0.000070	-0.000070	-0.000070	-0.000070
2028	7.9	5.2	5.0	4.5	-1.1	14	14	13
2029	8.0	5.3	5.2	4.6	-1.1	14	14	14
2030	11	3.6	3.4	3.0	-0.046	15	14	14
2031	11	3.6	3.5	3.1	-0.046	15	15	14
2032	29	14	14	12	1.2	42	42	40
2033	29	15	14	13	1.2	43	42	41
2034	30	15	15	13	1.2	44	43	42
2035	30	15	15	13	1.2	44	44	42
2036	31	16	15	13	1.2	45	45	43
2037	31	16	15	14	1.2	46	45	44
2038	14	0.0026	0.0025	0.0013	0.64	13	13	13
2039	14	0.0016	0.0016	0.00044	0.64	13	13	13
2040	14	0.00043	0.00045	-0.00065	0.64	13	13	13
2041	14	-0.0011	-0.00097	-0.0019	0.64	14	14	14
2042	11	8.0	7.7	6.9	3.3	16	15	15
2043	11	8.1	7.8	6.9	3.3	16	16	15
2044	11	8.1	7.9	7.0	3.3	16	16	15
2045	11	8.2	8.0	7.1	3.3	16	16	15
2046	12	8.3	8.1	7.2	3.3	17	16	15
2047	12	8.4	8.1	7.2	3.3	17	17	16

	Climate Benefits[b]	$PM_{2.5}$ and O_3-related Health Benefits[c]			Compliance Costs[d]			Net Benefits[e]		
	Discount Rate									
	2%	2%	3%	7%	2%	3%	7%	2%	3%	7%
PV	270	120	110	60	19	16	7.8	370	360	320
EAV	14	6.5	6.2	5.2	0.99	0.93	0.68	20	19	19

Non-Monetized Benefits[f]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from $PM_{2.5}$ reductions

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[a] Annual values from 2024 to 2047 are not discounted. PV and EAV values discounted to 2024. Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-5 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[c] The health benefits estimates use the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[d] The discount rate in IPM is 3.76 percent, as described in Section 3.

[e] In this net benefits analysis, health benefits and costs are discounted at the rates shown in the table (i.e., two percent, three percent, and seven percent). Climate benefits are discounted using a two percent discount rate only in this net benefits analysis.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

Table 7-8 Net Benefits of the Alternative 2 Illustrative Scenario for 2024 to 2047 (billion 2019 dollars) [a]

	Climate Benefits[b]	PM$_{2.5}$ and O$_3$-related Health Benefits[c]			Compliance Costs[d]	Net Benefits[e]		
	2%	2%	3%	7%		2%	3%	7%
2024	-	-	-	-	0.011	-0.011	-0.011	-0.011
2025	-	-	-	-	0.011	-0.011	-0.011	-0.011
2026	-	-	-	-	0.011	-0.011	-0.011	-0.011
2027	-	-	-	-	0.000070	-0.000070	-0.000070	-0.000070
2028	7.1	4.8	4.7	4.1	-1.1	13	13	12
2029	7.2	4.9	4.8	4.2	-1.1	13	13	12
2030	6.2	2.8	2.7	2.4	-0.72	9.7	9.6	9.3
2031	6.3	2.8	2.8	2.4	-0.72	9.9	9.8	9.5
2032	28	14	14	12	1.2	41	41	40
2033	29	15	14	13	1.2	42	42	40
2034	29	15	14	13	1.2	43	43	41
2035	30	15	15	13	1.2	44	43	42
2036	30	15	15	13	1.2	45	44	42
2037	31	16	15	14	1.2	45	45	43
2038	14	0.089	0.087	0.081	0.60	13	13	13
2039	14	0.088	0.086	0.080	0.60	13	13	13
2040	14	0.087	0.085	0.079	0.60	13	13	13
2041	14	0.085	0.083	0.077	0.60	14	14	14
2042	11	7.9	7.7	6.8	3.6	15	15	14
2043	11	8.0	7.8	6.9	3.6	16	15	14
2044	11	8.1	7.9	7.0	3.6	16	16	15
2045	11	8.2	8.0	7.1	3.6	16	16	15
2046	12	8.3	8.0	7.1	3.6	16	16	15
2047	12	8.4	8.1	7.2	3.6	17	16	15

	Climate Benefits[b]	PM$_{2.5}$ and O$_3$-related Health Benefits[c]			Compliance Costs[d]			Net Benefits[e]		
	Discount Rate									
	2%	2%	3%	7%	2%	3%	7%	2%	3%	7%
PV	250	120	100	58	19	15	7.2	360	340	310
EAV	13	6.3	6.1	5.1	0.98	0.91	0.63	19	19	18

Non-Monetized Benefits[f]

Benefits from reductions in HAP emissions

Benefits from improved water quality and availability

Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP

Reductions in exposure to ambient NO_2 and SO_2

Improved visibility (reduced haze) from PM$_{2.5}$ reductions

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[a] Annual values from 2024 to 2047 are not discounted. PV and EAV values discounted to 2024. Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the social cost of CO_2 (SC-CO_2) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CO_2 at the 2 percent near-term Ramsey discount rate. Please see Table 4-3 for the full range of monetized climate benefit estimates. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

[c] The health benefits estimates use the larger of the two benefits estimates presented in Table 4-15 through Table 4-19. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates.

[d] The discount rate in IPM is 3.76 percent, as described in Section 3.

[e] In this net benefits analysis, health benefits and costs are discounted at the rates shown in the table (i.e., two percent, three percent, and seven percent). Climate benefits are discounted using a two percent discount rate only in this net benefits analysis.

[f] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See Section 4.2 for a discussion of climate effects that are not yet reflected in the SC-CO_2 and thus remain unmonetized and Section 4.4 for a discussion of other non-monetized benefits.

APPENDIX A: CLIMATE BENEFITS

A.1 Climate Benefits Estimated using the Interim SC-CO_2 values used in the Proposal

This appendix presents the climate benefits of the final standards using the interim SC-CO_2 values used in the proposal of these rulemakings. The interim SC-CO_2 values are presented in Table A-1 and the climate benefits using these values are presented in Table A-2.

Table A-1 Interim SC-CO_2 Values, 2028 to 2047 (2019 dollars per metric ton)

	Discount Rate and Statistic			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	$18	$59	$86	$178
2029	$19	$60	$87	$181
2030	$19	$61	$88	$184
2031	$20	$62	$90	$188
2032	$20	$63	$91	$192
2033	$21	$64	$92	$196
2034	$21	$66	$94	$200
2035	$22	$67	$95	$203
2036	$23	$68	$96	$207
2037	$23	$69	$98	$211
2038	$24	$70	$99	$215
2039	$24	$71	$101	$218
2040	$25	$72	$102	$222
2041	$26	$73	$103	$226
2042	$26	$75	$105	$229
2043	$27	$77	$107	$235
2044	$28	$78	$108	$239
2045	$28	$29	$110	$242
2046	$29	$80	$111	$246
2047	$30	$81	$112	$249

Note: The 2028 to 2047 SC-CO_2 values are identical to those reported in the February 2021 SC-GHG TSD (IWG, 2021) adjusted to 2019 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, 2022). This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this analysis are available on OMB's website: https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs.

Table A-2 Stream of Projected Climate Benefits using Interim SC-CO_2 values under the Final Rules from 2028 to 2047 (millions of 2019 dollars, discounted to 2024)

Emissions Year	SC-CO_2 Discount Rate and Statistic			
	5%	3%	2.50%	3%
	Average	Average	Average	95th Percentile
2028	560	2,000	3,000	6,000
2029	570	2,000	2,900	5,900
2030	710	2,500	3,800	7,700
2031	710	2,500	3,800	7,600
2032	1,700	6,100	9,200	19,000
2033	1,700	6,100	9,100	19,000
2034	1,600	6,100	9,100	18,000
2035	1,600	6,000	8,900	18,000
2036	1,600	5,900	8,800	18,000
2037	1,500	5,800	8,800	18,000
2038	650	2,500	3,800	7,600
2039	620	2,400	3,700	7,500
2040	610	2,400	3,700	7,400
2041	610	2,400	3,600	7,300
2042	450	1,800	2,800	5,600
2043	450	1,800	2,800	5,600
2044	440	1,800	2,800	5,600
2045	420	650	2,700	5,500
2046	420	1,800	2,700	5,400
2047	410	1,700	2,700	5,300
PV	17,000	64,000	99,000	200,000
EAV	1,200	3,800	5,500	12,000

Note: Climate benefits are based on reductions in CO_2 emissions and are calculated using the IWG interim SC-CO_2 estimates from IWG (2021).

A.2 References

IWG. (2021). *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*. Washington DC: U.S. Government, Interagency Working Group (IWG) on Social Cost of Greenhouse Gases. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf?source=email

U.S. BEA. (2022). *Table 1.1.9. Implicit Price Deflators for Gross Domestic Product*. Washington, DC. https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=13

APPENDIX B: AIR QUALITY MODELING

As noted in Section 4, EPA used photochemical modeling to create air quality surfaces[198] that were then used in air pollution health benefits calculations of the three illustrative scenarios: the final rules, the alternative 1, and the alternative 2 scenarios. The modeling-based surfaces captured air pollution impacts resulting from changes in NO_X, SO_2 and direct $PM_{2.5}$ emissions from EGUs. This appendix describes the source apportionment modeling and associated methods used to create air quality surfaces for the baseline scenario and three illustrative scenarios in four snapshot years: 2028, 2030, 2035, 2040 and 2045. EPA created air quality surfaces for the following pollutants and metrics: annual average $PM_{2.5}$; April-September average of 8-hr daily maximum (MDA8) ozone (AS-MO3).

New ozone and PM source apportionment modeling outputs were created to support analyses in the RIAs for multiple final EGU rulemaking efforts. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (U.S. EPA, 2019, 2020a, 2020b, 2021b, 2022a). EPA calculated EGU emissions estimates of NO_X and SO_2 for baseline and illustrative scenarios in all five snapshot years using the Integrated Planning Model (IPM) (Section 3 of this RIA). EPA also used IPM outputs to estimate EGU emissions of $PM_{2.5}$ based on emission factors described in U.S. EPA (2021a).[199] This appendix provides additional details on the source apportionment modeling simulations and the associated analysis used to create ozone and $PM_{2.5}$ air quality surfaces.

B.1 Air Quality Modeling Simulations

The air quality modeling utilized a 2016-based modeling platform which included meteorology and base year emissions from 2016 and projected future-year emissions for 2026 for all sectors other than EGUs and 2030 for EGUs. The air quality modeling included photochemical model simulations for a 2016 base year and a future year representing the combined 2026/2030 emissions described above to provide hourly concentrations of ozone and $PM_{2.5}$ component species nationwide. In addition, source apportionment modeling was

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[198] The term “air quality surfaces” refers to continuous gridded spatial fields using a 12 km grid resolution.

[199] For details, please see *Flat File Generation Methodology and Post Processing Emissions Factors PM CO VOC NH_3 Updated Summer 2021 Reference Case*, available at: https://www.epa.gov/power-sector-modeling/supporting-documentation-2015-ozone-naaqs-actions

performed for the future year to quantify the contributions to ozone from NO_X emissions and to $PM_{2.5}$ from NO_X, SO_2 and directly emitted $PM_{2.5}$ emissions from EGUs on a state-by-state and fuel-type basis. As described below, the modeling results for 2016 and the future year, in conjunction with EGU emissions data for the baseline and three illustrative scenarios in 2028, 2030, 2035, 2040 and 2045 were used to construct the air quality surfaces that reflect the influence of emissions changes between the baseline and the three illustrative scenarios in each year.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.10[200] (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 is shown in Figure B-1. CAMx requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data, and initial and boundary concentrations. The meteorological data and the initial and boundary concentrations were identical to those described in U.S. EPA (2023a). Separate emissions inventories were prepared for the 2016 base year and the projected future year. All other inputs (i.e., meteorological fields, initial concentrations, ozone column, photolysis rates, and boundary concentrations) were specified for the 2016 base year model application and remained unchanged for the projection-year model simulation.

2016 base year emissions are described in detail in U.S. EPA (2023b). The types of sources included in the emission inventory include stationary point sources such as EGUs and non-EGUs; non-point emissions sources including those from oil and gas production and distribution, agriculture, residential wood combustion, fugitive dust, and residential and commercial heating and cooking; mobile source emissions from onroad and nonroad vehicles, aircraft, commercial marine vessels, and locomotives; wild, prescribed, and agricultural fires; and biogenic emissions from vegetation and soils. Future year emissions from all sources other than EGUs were based on the 2026 emissions projections described in U.S. EPA (2023b). The

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[200] 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.

Post-IRA 2022 Reference Case of the EPA's Power Sector Platform v6 using Integrated Planning Model (IPM), which includes the Final GNP, was also reflected.[201] The EGU projected inventory represents demand growth, fuel resource availability, generating technology cost and performance, and other economic factors affecting power sector behavior. It also reflects environmental rules and regulations, consent decrees and settlements, plant closures, and newly built units for the calendar year 2030. In this analysis, the projected EGU emissions include provisions of tax incentives impacting electricity supply in the Inflation Reduction Act of 2022 (IRA), Final GNP, 2021 Revised Cross-State Air Pollution Rule Update (RCU), the 2016 Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources, the Mercury and Air Toxics Rule (MATS) finalized in 2011, and other finalized rules. Documentation and results of the Post-IRA 2022 Reference Case, where the Final GNP was also included for EGUs, are available at (https://www.epa.gov/power-sector-modeling/final-pm-naaqs).

Model predictions of ozone and $PM_{2.5}$ concentrations were compared against ambient measurements (U.S. EPA, 2023a, 2024). Ozone and $PM_{2.5}$ model evaluations showed model performance that was adequate for applying these model simulations for the purpose of creating air quality surfaces to estimate ozone and $PM_{2.5}$ benefits.

Figure B-1 Air Quality Modeling Domain

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[201] https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case

The contributions to ozone and $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[202]) from EGU emissions in individual states and from each EGU-fuel type were modeled using the "source apportionment" tool approach. In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags". These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[203] 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 of 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 source apportionment modeling for ozone and $PM_{2.5}$ component species using the future year modeled case to obtain the contributions from EGUs emissions in each state and fuel-type to ozone and $PM_{2.5}$ component species concentrations in each 12 km model grid resolution nationwide. 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 Environ, 2021). 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 maximum daily eight hour (MDA8) (i.e., AS-MO3) average ozone concentration exposure metric. The $PM_{2.5}$ source apportionment modeling was performed for a full year to provide data for developing annual average $PM_{2.5}$ spatial fields. Table B-1, Table B-2, and Table B-3 provide emissions that were tracked for each source apportionment tag.

Table B-1 Future-year Emissions Allocated to Each Modeled Coal EGU State Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
AL	2,537	5,046	1,929	700
AR[4]	NA	304	331	51

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[202] 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.

[203] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag

AZ	1,005	2,536	4,515	609
CA	222	511	99	27
CO	19	269	287	21
CT	0	0	0	0
DC	0	0	0	0
DE	0	0	0	0
FL	1,110	1,401	7,163	277
GA	1,654	2,534	3,247	159
IA	8,354	18,776	9,656	1,203
ID	0	0	0	0
IL	1,639	3,742	6,773	270
IN	4,886	18,146	26,584	2,252
KS[1]	NA	214	121	NA
KY	3,551	7,333	7,127	560
LA[2,4]	NA	47	NA	NA
MA	0	0	0	0
MD[3]	NA	139	272	31
MD + PA[3]	708	NA	NA	NA
ME	0	0	0	0
MI	1,532	4,071	12,478	380
MN	724	1,549	3,289	94
MO	2,947	23,480	38,989	853
MS[4]	NA	252	507	23
MT	3,771	8,842	4,056	1,252
NC	266	482	634	35
ND	8,583	19,562	25,398	1,923
NE[1]	7,817	17,507	43,858	NA
NE + KS[1]	NA	NA	NA	374
NH	0	0	0	0
NJ	0	0	0	0
NM	1,442	2,757	6,800	1,739
NV	0	1	1	0
NY	0	0	0	0
OH	3,152	10,485	21,721	901
OK[4]	NA	212	152	21
OR	0	0	0	0
PA[3]	NA	1,530	4,932	167
RI	0	0	0	0
SC	807	1,939	3,429	364
SD	418	1,100	1,022	27
TN	259	259	269	32
TX[2,4]	NA	7,031	NA	NA
TX + LA[2]	NA	NA	11,607	1,578
TX-reg[4]	2,698	NA	NA	NA

UT	2,702	4,236	7,625	232
VA	466	1,124	259	445
VT	0	0	0	0
WA	0	0	0	0
WI	866	2,137	838	90
WV	6,824	16,358	17,631	1,753
WY	6,066	13,222	11,754	1,024

[1] KS and NE emissions grouped into multi-state tag for direct $PM_{2.5}$

[2] LA and TX emissions grouped into multi-state tag for SO_2 and direct $PM_{2.5}$

[3] MD and PA emissions grouped into multi-state tag for ozone season NO_X

[4] AR, KS, LA, MS, OK and TX emissions grouped into multi-state tag ("TX-reg") for ozone season NO_X

Table B-2 Future-year Emissions Allocated to Each Modeled Natural Gas EGU State Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
AL	2,833	5,132	0	1,979
AR	1,651	2,957	0	632
AZ	1,759	3,146	0	686
CA	1,960	5,773	0	1,964
CO	957	1,825	0	461
CT	461	778	0	160
DC	6	11	0	7
DE	383	502	0	134
FL	7,550	14,372	0	4,996
GA	2,279	4,182	0	1,740
IA	875	1,106	0	327
ID	336	513	0	185
IL	1,624	2,705	0	825
IN	1,180	2,166	0	955
KS	329	621	0	54
KY	980	2,806	0	699
LA	3,771	8,706	0	2,158
MA	482	725	0	244
MD	402	710	0	435
ME	232	273	0	21
MI	6,523	11,372	0	1,508
MN	661	928	0	87
MO	587	875	0	342
MS	1,926	3,860	0	1,140
MT	11	19	0	7
NC	1,803	3,426	0	1,213
ND	25	41	0	3
NE	13	47	0	4
NH	120	136	0	34

NJ	1,024	1,910	0	608
NM	733	1,128	0	131
NV	1,693	2,471	0	648
NY	2,793	5,125	0	1,270
OH	1,838	3,824	0	1,617
OK	1,558	2,448	0	546
OR	5	188	0	87
PA	6,811	12,386	0	3,280
RI	115	153	0	73
SC	1,092	2,090	0	917
SD	93	105	0	11
TN	464	1,107	0	388
TX	7,652	14,715	0	3,567
UT	1,189	1,779	0	514
VA	1,836	3,409	0	1,087
VT	4	8	0	6
WA	485	1,311	0	464
WI	847	1,447	0	369
WV	109	180	0	50
WY	203	206	0	28

Table B-3 Future-year Emissions Allocated to the Modeled Other EGU Source Apportionment Tag

State	Ozone Season NO$_X$ (tons)	Annual NO$_X$ (tons)	Annual SO$_2$ (tons)	Annual PM$_{2.5}$ (tons)
US[a]	20,611	48,619	9,631	7,915

[a] Only includes US emissions from the contiguous 48 states

Examples of the magnitude and spatial extent of ozone and PM$_{2.5}$ contributions are provided in Figure B-2 through Figure B-5 for EGUs in California, Georgia, Iowa, and Ohio. These figures show how the magnitude and the spatial patterns of contributions of EGU emissions to ozone and PM$_{2.5}$ component species depend on multiple factors including the magnitude and location of emissions as well as the atmospheric conditions that influence the formation and transport of these pollutants. For instance, NO$_X$ emissions are a precursor to both ozone and PM$_{2.5}$ nitrate. However, ozone and nitrate form under very different types of atmospheric conditions, with ozone formation occurring in locations with ample sunlight and ambient VOC concentrations while nitrate formation requires colder and drier conditions and the presence of gas-phase ammonia. California's complex terrain that tends to trap air and allow pollutant build-up combined with warm sunny summer and cooler dry winters and sources of both ammonia and VOCs make its atmosphere conducive to formation of both ozone and nitrate. While the magnitude of EGU NO_X emissions from gas plus coal EGUs is substantially larger in Iowa than in California (Table B-1 and Table B-2) the emissions from California lead to larger maximum contributions to the formation of those pollutants due to the conducive conditions in that state. Georgia and Ohio both had substantial NO_X emissions. While maximum ozone impacts shown for Georgia and Ohio EGUs are similar order of magnitude to maximum ozone impacts from California EGUs, nitrate impacts are negligible in both Georgia and Ohio due to less conducive atmospheric conditions for nitrate formation in those locations. California EGU SO_2 emissions in the future year source apportionment modeling are several orders of magnitude smaller than SO_2 emissions in Ohio and Georgia (Table B-1) leading to much smaller sulfate contributions from California EGUs than from Ohio and Georgia EGUs. $PM_{2.5}$ organic aerosol EGU contributions in this modeling come from primary $PM_{2.5}$ emissions rather than secondary atmospheric formation. Consequently, the impacts of EGU emissions on this pollutant tend to occur closer to the EGU sources than impacts of secondary pollutants (ozone, nitrate, and sulfate) which have spatial patterns showing a broader regional impact. These patterns demonstrate how the model captures important atmospheric processes which impact pollutant formation and transport from emissions sources. Finally, Figure B-6 and Figure B-7 show EGU ozone and $PM_{2.5}$ contributions from all contiguous U.S. EGUs split out by fuel type. The spatial differences between coal EGU, natural gas EGU, and other EGU contributions reflect the varying location and magnitude of emissions from each type of EGU.

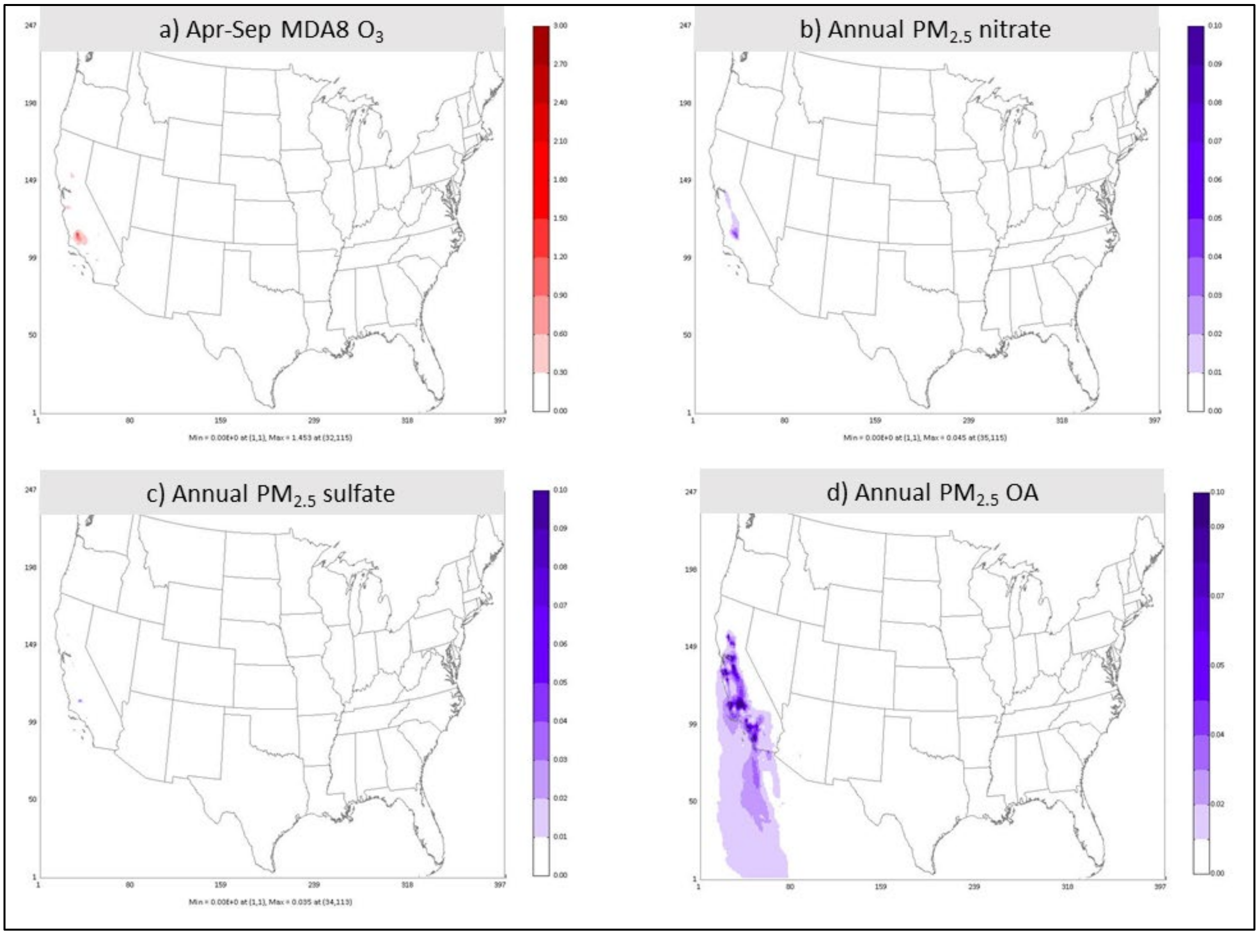

Figure B-2 Maps of California EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate (µg/m^3); c) Annual Average $PM_{2.5}$ sulfate (µg/m^3); d) Annual Average $PM_{2.5}$ Organic Aerosol (µg/m^3)

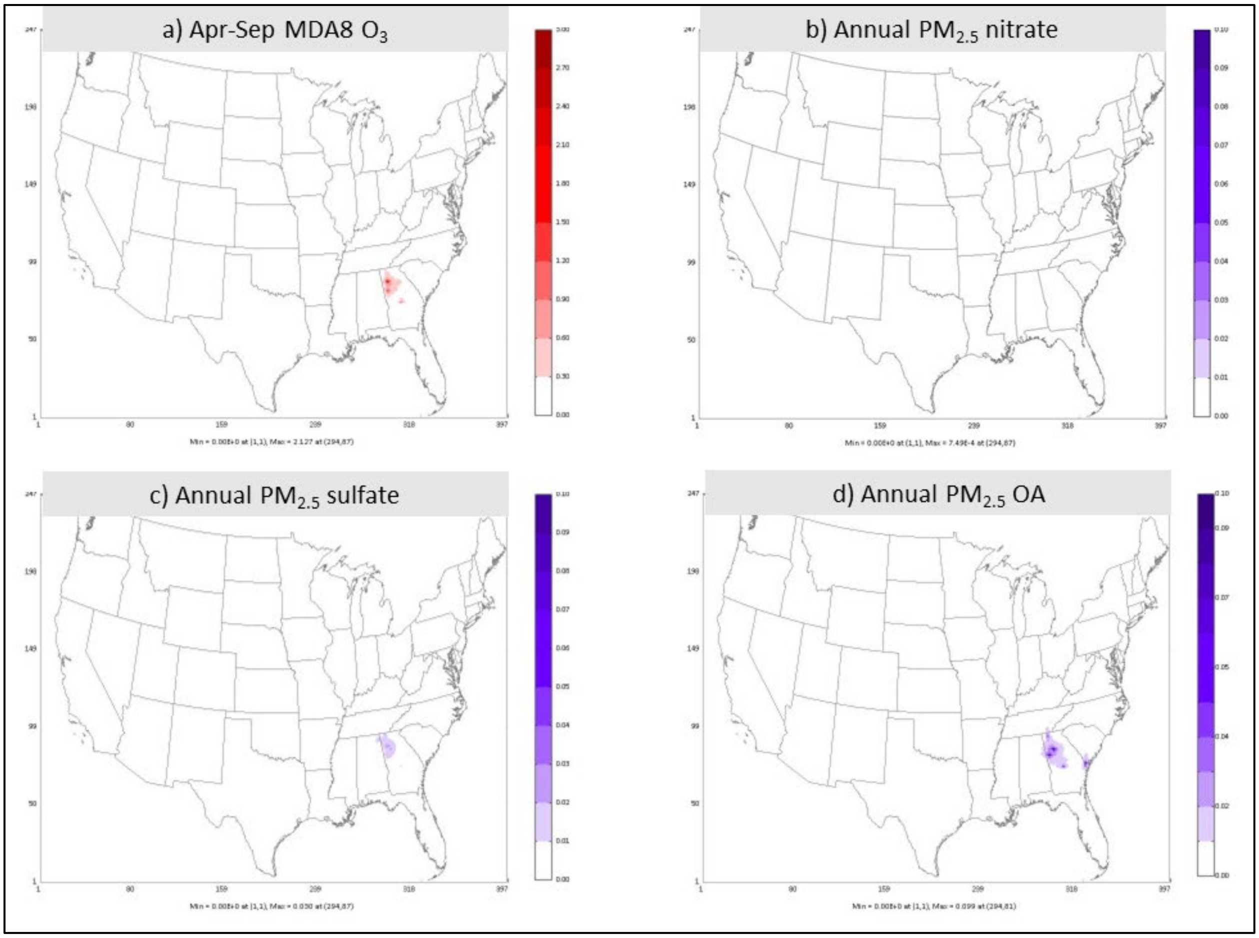

Figure B-3 Maps of Georgia EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate (µg/m^3); c) Annual Average $PM_{2.5}$ sulfate (µg/m^3); d) Annual Average $PM_{2.5}$ Organic Aerosol (µg/m^3)

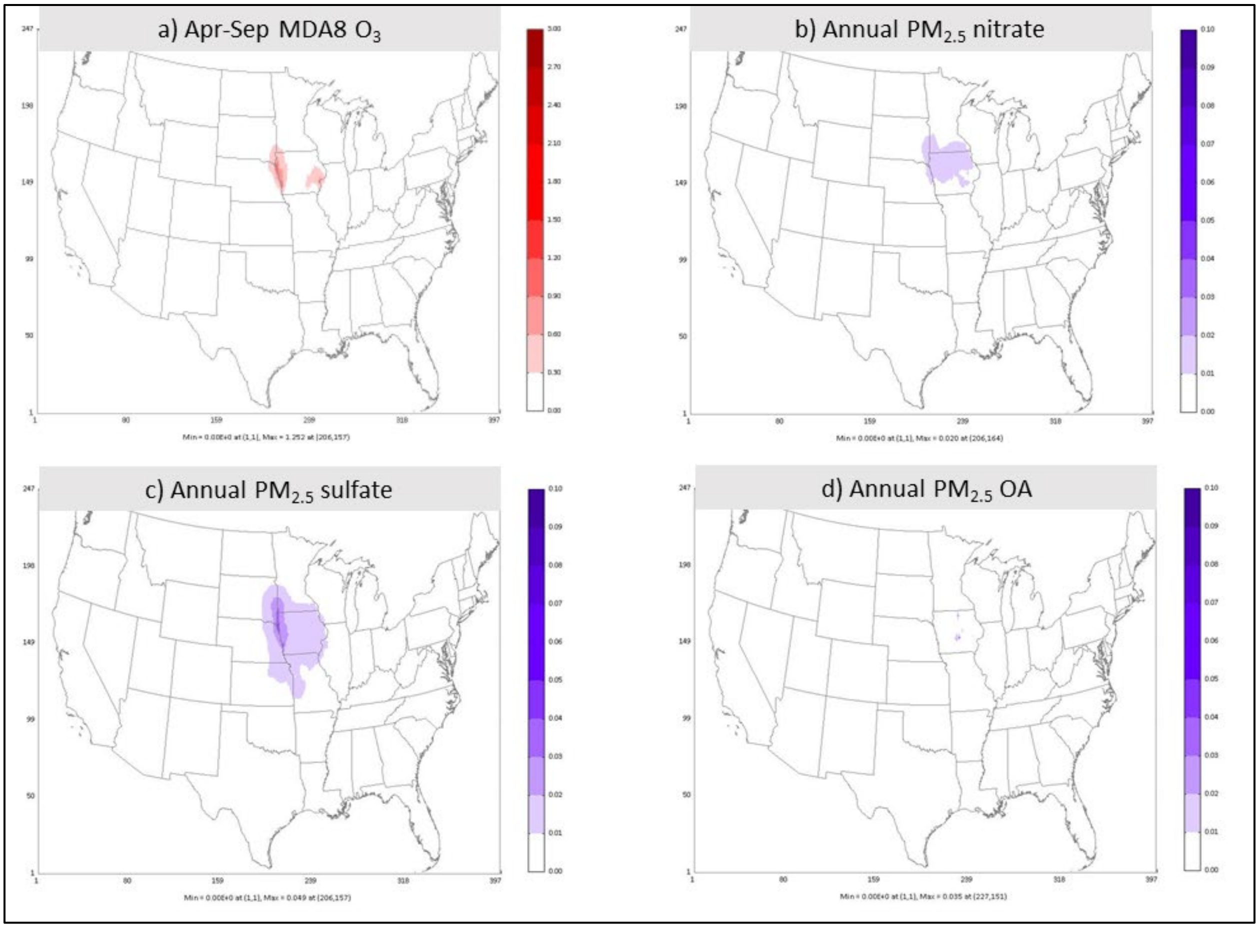

Figure B-4 Maps of Iowa EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate (µg/m^3); c) Annual Average $PM_{2.5}$ sulfate (µg/m^3); d) Annual Average $PM_{2.5}$ Organic Aerosol (µg/m^3)

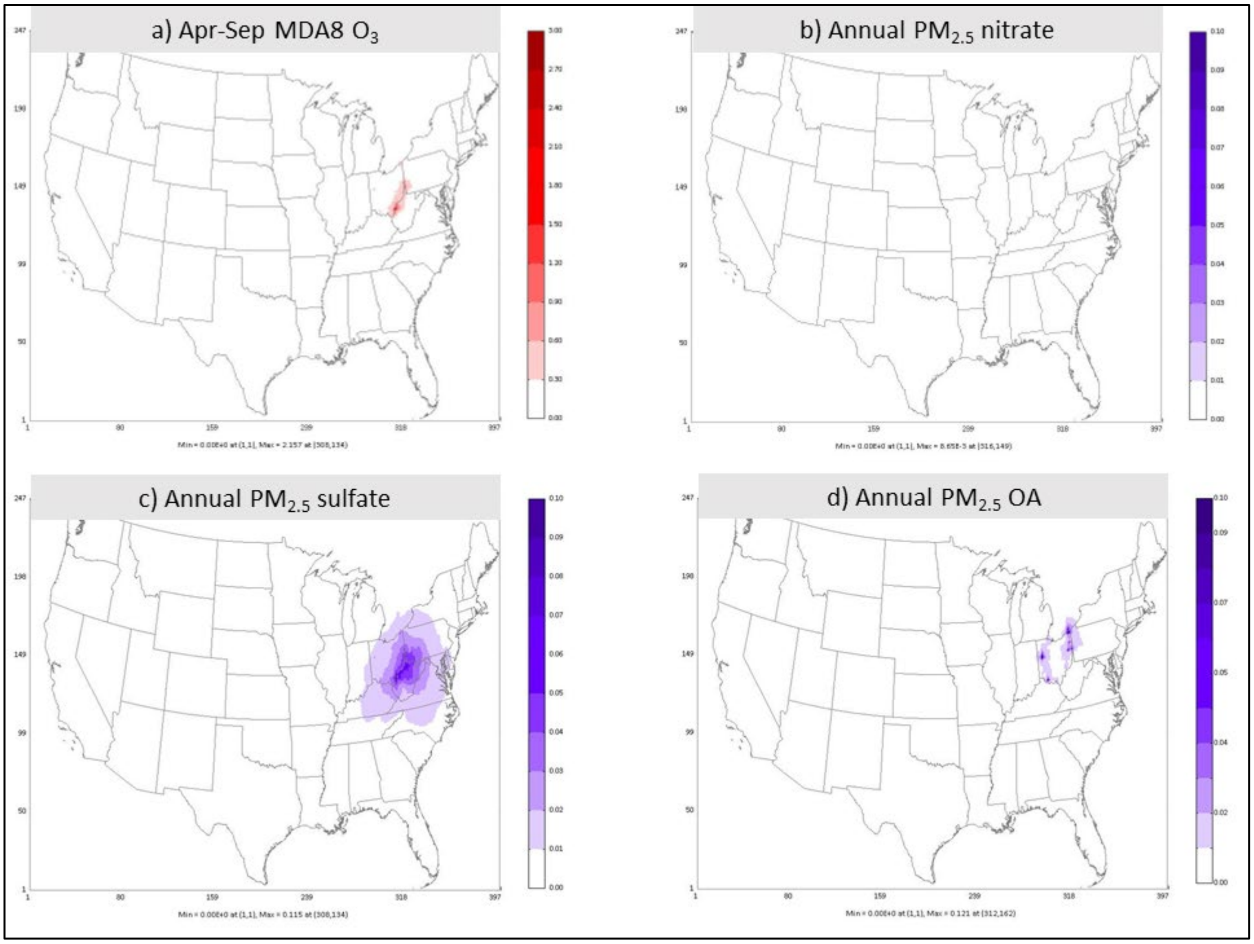

Figure B-5 Maps of Ohio EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

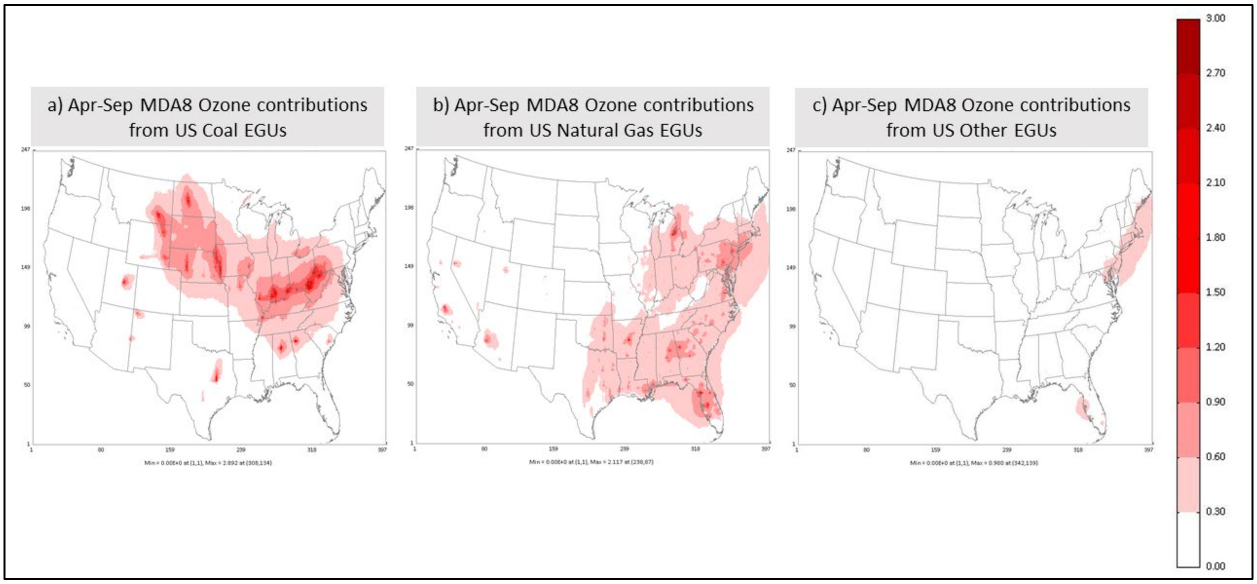

Figure B-6 Maps of National EGU Tag contributions to April-September Seasonal Average MDA8 ozone (ppb) by fuel for a) Coal EGUs; b) Natural Gas EGUs; c) All Other EGUs

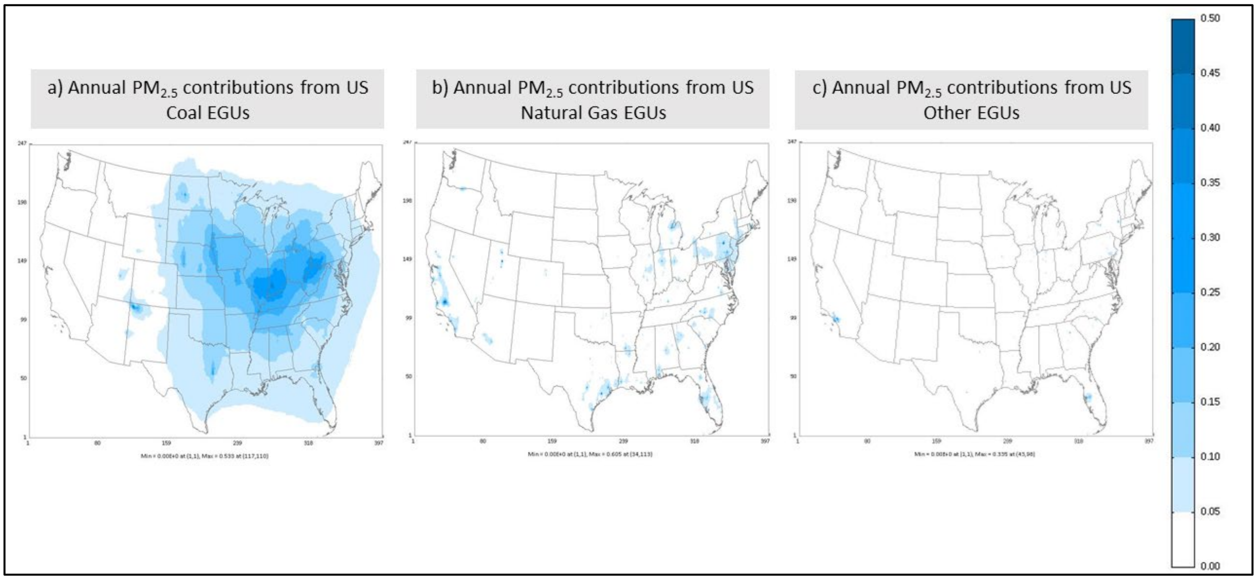

Figure B-7 Maps of National EGU Tag contributions to Annual Average $PM_{2.5}$ ($\mu g/m^3$) by fuel for a) Coal EGUs; b) Natural Gas EGUs; c) All Other EGUs

B.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 2016 and future year modeling. The foundational data include (1) ozone and speciated $PM_{2.5}$ concentrations in each model grid cell from the 2016 and the future year modeling, (2) ozone and speciated $PM_{2.5}$ contributions in the future year of EGUs emissions from each state in each model grid cell[204], (3) future year emissions from EGUs that were input to the contribution modeling (Table B-1, Table B-2 and Table B-3), and (4) the EGU emissions from IPM for baseline and the three illustrative scenarios in each snapshot year. The method to create spatial fields applies scaling factors to gridded source apportionment contributions based on emissions changes between future year projections and the baseline and the three illustrative scenarios to the modeled contributions. This method is described in detail below.

Spatial fields of ozone and $PM_{2.5}$ in the future year 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, the fused future year model fields are used in combination with the EGU source apportionment modeling and the EGU emissions for each scenario and snapshot year. Contributions from each state and fuel EGU contribution "tag" were scaled based on the ratio of emissions in the year/scenario being evaluated to the emissions in the modeled future year scenario. Contributions from tags representing sources other than EGUs are held constant at 2026 levels for each of the scenarios and years. For each scenario 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 starting with the methodology for creating AS-MO3 spatial fields followed by a description of the steps for creating annual $PM_{2.5}$ spatial fields.

Ozone:

1. Create fused spatial fields of future year AS-MO3 incorporating information from the air quality modeling and from ambient measured monitoring data. The enhanced Voronoi Neighbor Average (eVNA) technique (Ding et al., 2016; Gold et al., 1997; U.S. EPA, 2007) was applied to ozone model predictions in conjunction with measured data to create modeled/measured fused surfaces that leverage measured concentrations at air quality monitor locations and model predictions at locations with no monitoring data.
    1.1. The AS-MO3 eVNA spatial fields are created for the 2016 base year with EPA's software package, Software for the Modeled Attainment Test – Community Edition

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[204] Contributions from EGUs were modeled using projected emissions for the future year modeled scenario. The resulting contributions were used to construct spatial fields in 2028, 2030, 2035, 2040 and 2045.

(SMAT-CE)[205] (U.S. EPA, 2022b) using 3 years of monitoring data (2015-2017) and the 2016 modeled data.

1.2. The model-predicted spatial fields (i.e., not the eVNA fields) of AS-MO3 in 2016 were paired with the corresponding model-predicted spatial fields in future year to calculate the ratio of AS-MO3 between 2016 and the future year in each model grid cell.

1.3. To create a gridded future year eVNA surfaces, the spatial fields of 2016/future year ratios created in step (1.2) were multiplied by the corresponding eVNA spatial fields for 2016 created in step (1.1) to produce an eVNA AS-MO3 spatial field for the future year using (Eq-1).

$$eVNA_{g,future} = \left(eVNA_{g,2016}\right) \times \frac{Model_{g,future}}{Model_{g,2016}} \qquad \text{Eq-1}$$

- $eVNA_{g,future}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the future year
- $eVNA_{g,2016}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in 2016
- $Model_{g,future}$ is the CAMx modeled concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the future year
- $Model_{g,2016}$ is the CAMx modeled concentration of AS-MO3 or $PM_{2.5}$ component in grid-cell, g, in 2016

2. Create gridded spatial fields of total EGU AS-MO3 contributions for each combination of scenario and analysis year evaluated.

2.1. Use the EGU ozone season NO_X emissions for the 2028 baseline and the corresponding future year modeled EGU ozone season emissions (Table B-1, Table B-2, and Table B-3) to calculate the ratio of 2028 baseline emissions to future year modeled emissions for each EGU tag (i.e., an ozone scaling factor calculated for each state-fuel

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[205] SMAT-CE available for download at https://www.epa.gov/scram/photochemical-modeling-tools.

combination)[206]. These scaling factors are provided in Table B-4, Table B-5, Table B-6, Table B-7, Table B-18 and Table B-19.

   2.2. Calculate adjusted gridded AS-MO3 EGU contributions that reflect differences in state-fuel EGU NO_X emissions between the modeled future year and the 2028 baseline by multiplying the ozone season NO_X scaling factors by the corresponding gridded AS-MO3 ozone contributions[207] from each state-fuel EGU tag.

   2.3. Add together the adjusted AS-MO3 contributions for each state-fuel EGU tag to produce spatial fields of adjusted EGU totals for the 2028 baseline.[208]

   2.4. Repeat steps 2.1 through 2.3 for the three 2028 illustrative scenarios and for the baseline and illustrative scenarios for each additional snapshot year. All scaling factors for the baseline scenario and the three illustrative scenarios are provided in Table B-4, Table B-5, Table B-6, Table B-7, Table B-18 and Table B-19.

3. Create a gridded spatial field of AS-MO3 associated with IPM emissions for the 2028 baseline by combining the EGU AS-MO3 contributions from step (2.3) with the corresponding contributions to AS-MO3 from all other sources. Repeat for each of the EGU contributions created in step (2.4) to create separate gridded spatial fields for the baseline and three illustrative scenarios for each snapshot year.

Steps 2 and 3 in combination can be represented by equation 2:

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[206] State-level tags were tracked for separately for coal EGUs and for natural gas EGUs. All other EGU emissions were tracked using a single national tag. In addition, preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state-fuel EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

[207] The source apportionment modeling provided separate ozone contributions for ozone formed in VOC-limited chemical regimes (O3V) and ozone formed in NO_X-limited chemical regimes (O3N). The emissions scaling factors are multiplied by the corresponding O3N gridded contributions to MDA8 concentrations. Since there are no predicted changes in VOC emissions in the control scenarios, the O3V contributions remain unchanged.

[208] The contributions from the unaltered O3V tags are added to the summed adjusted O3N EGU tags.

$$\text{AS-MO3}_{\text{g,i,y}} = \text{eVNA}_{\text{g,future}} \times \left(\frac{\text{C}_{\text{g,BC}}}{\text{C}_{\text{g,Tot}}} + \frac{\text{C}_{\text{g,int}}}{\text{C}_{\text{g,Tot}}} + \frac{\text{C}_{\text{g,bio}}}{\text{C}_{\text{g,Tot}}} + \frac{\text{C}_{\text{g,fires}}}{\text{C}_{\text{g,Tot}}} + \frac{\text{C}_{\text{g,USanthro}}}{\text{C}_{\text{g,Tot}}} + \sum_{\text{t=1}}^{\text{T}} \frac{\text{C}_{\text{EGUVOC,g,t}}}{\text{C}_{\text{g,Tot}}} + \sum_{\text{t=1}}^{\text{T}} \frac{\text{C}_{\text{EGUNOx,g,t}}\,\text{S}_{\text{NOx,t,i,y}}}{\text{C}_{\text{g,Tot}}} \right) \qquad \text{Eq-2}$$

- $AS\text{-}MO3_{g,i,y}$ is the estimated fused model-obs AS-MO3 for grid-cell, “g”, scenario, “i”[209], and year, “y”[210];
- $eVNA_{g,future}$ is the future year eVNA future year AS-MO3 concentration for grid-cell “g” calculated using Eq-1.
- $C_{g,Tot}$ is the total modeled AS-MO3 for grid-cell “g” from all sources in the future year source apportionment modeling
- $C_{g,BC}$ is the future year AS-MO3 modeled contribution from the modeled boundary inflow;
- $C_{g,int}$ is the future year AS-MO3 modeled contribution from international emissions within the modeling domain;
- $C_{g,bio}$ is the future year AS-MO3 modeled contribution from biogenic emissions;
- $C_{g,fires}$ is the future year AS-MO3 modeled contribution from fires;
- $C_{g,USanthro}$ is the total future year AS-MO3 modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUVOC,g,t}$ is the future year AS-MO3 modeled contribution from EGU emissions of VOCs from state, “t”;
- $C_{EGUNOx,g,t}$ is the future year AS-MO3 modeled contribution from EGU emissions of NO_X from tag, “t”; and
- $S_{NOx,t,i,y}$ is the EGU NO_X scaling factor for tag, “t”, scenario “i”, and year, “y”.

$PM_{2.5}$

4. Create fused spatial fields of future year annual $PM_{2.5}$ component species incorporating information from the air quality modeling and from ambient measured monitoring data. The eVNA technique was applied to $PM_{2.5}$ component species model predictions in conjunction

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[209] Scenario “i" can represent either the baseline or one of the three illustrative scenarios

[210] Snapshot year “y” can represent 2028, 2030, 2035, 2040 or 2045

with measured data to create modeled/measured fused surfaces that leverage measured concentrations at air quality monitor locations and model predictions at locations with no monitoring data.

4.1. The quarterly average $PM_{2.5}$ component species eVNA spatial fields are created for the 2016 base year with EPA's SMAT-CE software package using 3 years of monitoring data (2015-2017) and the 2016 modeled data.

4.2. The model-predicted spatial fields (i.e., not the eVNA fields) of quarterly average $PM_{2.5}$ component species in 2016 were paired with the corresponding model-predicted spatial fields in the future year to calculate the ratio of $PM_{2.5}$ component species between 2016 and the future year in each model grid cell.

4.3. To create a gridded future year eVNA surfaces, the spatial fields of 2016/future year ratios created in step (4.2) were multiplied by the corresponding eVNA spatial fields for 2016 created in step (4.1) to produce an eVNA annual average $PM_{2.5}$ component species spatial field for the future year using Eq-1.

5. Create gridded spatial fields of total EGU speciated $PM_{2.5}$ contributions for each combination of scenario and snapshot year.

5.1. Use the EGU annual total NO_X, SO_2, and $PM_{2.5}$ emissions for the 2028 baseline scenario and the corresponding future year modeled EGU NO_X, SO_2, and $PM_{2.5}$ emissions from Table B-1, Table B-2, and Table B-3 to calculate the ratio of 2028 baseline emissions to future year modeled emissions for each state-fuel EGU contribution tag (i.e., annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors calculated for each state-fuel tag)[211]. These scaling factors are provided in Table B-8 through Table B-19.

5.2. Calculate adjusted gridded annual $PM_{2.5}$ component species EGU contributions that reflect differences in state-fuel EGU NO_X, SO_2, and primary $PM_{2.5}$ emissions between the future modeled year and the 2028 baseline by multiplying the annual nitrate, sulfate

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[211] State-level tags were tracked for separately for coal EGUs and for natural gas EGUs. All other EGU emissions were tracked using a single national tag. In addition, preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state-fuel EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

and directly emitted $PM_{2.5}$ scaling factors by the corresponding annual gridded $PM_{2.5}$ component species contributions from each state-fuel EGU tag[212].

5.3. Add together the adjusted $PM_{2.5}$ contributions of for each EGU state-fuel tag to produce spatial fields of adjusted EGU totals for each $PM_{2.5}$ component species.

5.4. Repeat steps 5.1 through 5.3 for the three illustrative scenarios in 2028 and for the baseline and illustrative scenarios for each additional snapshot year. The scaling factors for all $PM_{2.5}$ component species for the baseline and illustrative scenarios are provided in Table B-8 through Table B-19.

6. Create gridded spatial fields of each $PM_{2.5}$ component species for the 2028 baseline by combining the EGU annual $PM_{2.5}$ component species contributions from step (5.3) with the corresponding contributions to annual $PM_{2.5}$ component species from all other sources. Repeat for each of the EGU contributions created in step (5.4) to create separate gridded spatial fields for the baseline and three illustrative scenarios for all other snapshot years.
7. Create gridded spatial fields of total $PM_{2.5}$ mass by combining the component species surfaces for sulfate, nitrate, organic aerosol, elemental carbon and crustal material with ammonium, and particle-bound. Ammonium and particle-bound water concentrations are calculated for each scenario based on nitrate and sulfate concentrations along with the ammonium degree of neutralization in the base year modeling (2016) in accordance with equations from the SMAT-CE modeling software (U.S. EPA, 2022b).

Steps 5 and 6 result in Eq-3 for $PM_{2.5}$ component species: sulfate, nitrate, organic aerosol, elemental carbon and crustal material.

$$\begin{aligned} \mathrm{PM}_{s,g,i,y} = {} & \mathrm{eVNA}_{s,g,future} \\ & \times \left(\frac{C_{s,g,BC}}{C_{s,g,Tot}} + \frac{C_{s,g,int}}{C_{s,g,Tot}} + \frac{C_{s,g,bio}}{C_{s,g,Tot}} + \frac{C_{s,g,fires}}{C_{s,g,Tot}} + \frac{C_{s,g,USanthro}}{C_{s,g,Tot}} \right. \\ & \left. + \sum_{t=1}^{T} \frac{C_{EGUs,g,t}\, S_{s,t,i,y}}{C_{s,g,Tot}} \right) \end{aligned} \qquad \text{Eq-3}$$

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[212] Scaling factors for components that are formed through chemical reactions in the atmosphere were created as follows: scaling factors for sulfate were based on relative changes in annual SO_2 emissions; scaling factors for nitrate were based on relative changes in annual NO_X emissions. Scaling factors for $PM_{2.5}$ components that are emitted directly from the source (OA, EC, crustal) were based on the relative changes in annual primary $PM_{2.5}$ emissions between the future year modeled emissions and the baseline and the three illustrative scenarios in each snapshot year.

- $PM_{s,g,i,y}$ is the estimated fused model-obs PM component species "s" for grid-cell, "g", scenario, "i"[213], and year, "y"[214];
- $eVNA_{s,g,future}$ is the future year eVNA PM concentration for component species "s" in grid-cell "g" calculated using Eq-1.
- $C_{s,g,Tot}$ is the total modeled PM component species "s" for grid-cell "g" from all sources in the future year source apportionment modeling
- $C_{s,g,BC}$ is the future year PM component species "s" modeled contribution from the modeled boundary inflow;
- $C_{s,g,int}$ is the future year PM component species "s" modeled contribution from international emissions within the modeling domain;
- $C_{s,g,bio}$ is the future year PM component species "s" modeled contribution from biogenic emissions;
- $C_{s,g,fires}$ is the future year PM component species "s" modeled contribution from fires;
- $C_{s,g,USanthro}$ is the total future year PM component species "s" modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUs,g,t}$ is the future year PM component species "s" modeled contribution from EGU emissions of NO_X, SO_2, or primary $PM_{2.5}$ from tag, "t"; and
- $S_{s,t,i,y}$ is the EGU scaling factor for component species "s", tag, "t", scenario "i", and year, "y". Scaling factors for nitrate are based on annual NO_X emissions, scaling factors for sulfate are based on annual SO_2 emissions, scaling factors for primary $PM_{2.5}$ components are based on primary $PM_{2.5}$ emissions

B.3 Scaling Factors Applied to Source Apportionment Tags

Table B-4 Baseline and Alternative 1 Scenario Ozone Scaling Factors for Coal EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	1.20	1.40	1.47	1.38	0.29	1.16	1.40	1.41	1.41	0.00
AZ	0.01	1.43	1.13	0.00	0.00	0.01	1.52	0.77	0.77	0.00

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[213] Scenario "i" can represent either baseline or one of the illustrative scenarios.

[214] Snapshot year "y" can represent 2028, 2030, 2035, 2040, or 2045

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
CA	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00
CO	139.01	1.28	1.98	1.98	1.98	143.12	5.46	1.98	1.98	1.98
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.47	1.24	0.10	0.10	0.03	0.47	1.16	0.12	0.12	0.03
GA	0.00	0.18	0.00	0.00	0.00	0.11	0.21	0.00	0.00	0.00
IA	1.17	1.18	0.77	0.46	0.42	1.15	0.88	0.04	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.97	0.96	0.81	0.14	0.00	0.97	0.96	1.00	1.00	0.00
IN	1.35	0.76	0.19	0.19	0.00	1.24	0.74	0.19	0.19	0.00
KY	0.79	0.95	0.97	0.83	0.06	0.80	0.92	0.90	0.90	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MDPA[a]	3.14	3.17	2.58	1.06	1.30	3.09	2.99	1.74	1.74	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.75	0.00	0.00	0.00	0.00	0.75	0.00	0.00	0.00	0.00
MN	2.41	2.25	0.00	0.00	0.00	2.41	2.25	0.00	0.00	0.00
MO	2.72	1.57	0.67	0.31	0.27	2.57	1.37	0.52	0.52	0.01
MT	1.07	1.12	1.11	0.99	0.00	1.07	1.07	0.42	0.36	0.00
NC	9.89	6.41	2.86	1.50	2.86	8.81	10.07	0.00	0.13	0.00
ND	1.09	1.08	0.25	0.24	0.01	1.01	1.01	0.26	0.26	0.01
NE	1.16	1.18	0.73	0.55	0.41	1.15	1.15	0.12	0.10	0.02
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.98	0.01	0.01	0.01	0.98	0.98	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.58	1.07	0.00	0.00	0.00	0.35	1.07	0.08	0.08	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.81	2.22	3.18	3.18	0.00	0.00	2.35	3.18	3.18	0.00
SD	0.87	1.33	0.00	0.00	0.00	0.87	1.33	0.00	0.00	0.00
TN	3.89	0.01	0.00	0.00	0.00	3.12	0.41	0.00	0.00	0.00
TX-reg[b]	4.69	4.26	1.64	1.15	0.54	3.66	3.09	1.52	1.52	0.06
UT	1.00	0.06	0.06	0.06	0.04	1.00	0.06	0.00	0.00	0.00
VA	0.65	0.45	0.00	0.00	0.00	0.65	0.45	0.01	0.01	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.66	2.16	0.36	0.00	0.00	1.65	0.64	0.01	0.01	0.00
WV	0.92	1.16	0.92	0.27	0.10	0.93	1.20	0.25	0.25	0.00
WY	1.26	1.12	1.12	0.61	0.53	1.22	0.99	0.57	0.28	0.06

Note: Emissions of Maryland, Arkansas, Kansas, Louisiana, Oklahoma, and Mississippi are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.
[a] MDPA: Maryland and Pennsylvania
[b] TX-reg: Arkansas, Kansas, Louisiana, Oklahoma, Mississippi, Texas

Table B-5 Alternative 2 and Final Rules Scenario Ozone Scaling Factors for Coal EGU Tags

	Alternative 2					Final Rules				
State Tag	**2028**	**2030**	**2035**	**2040**	**2045**	**2028**	**2030**	**2035**	**2040**	**2045**
AL	1.17	1.40	1.41	1.41	0.00	1.17	1.40	1.41	1.41	0.00
AZ	0.01	1.60	0.78	0.78	0.00	0.01	1.52	0.77	0.77	0.00
CA	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00
CO	139.01	1.28	1.98	1.98	1.98	146.51	6.20	1.98	1.98	1.98
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.47	1.24	0.12	0.12	0.03	0.47	1.16	0.12	0.12	0.03
GA	0.00	0.17	0.00	0.00	0.00	0.02	0.18	0.00	0.00	0.00
IA	1.14	1.14	0.17	0.00	0.00	1.15	0.88	0.04	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.97	0.96	1.00	1.00	0.00	0.97	0.96	1.00	1.00	0.00
IN	1.29	0.76	0.19	0.19	0.00	1.23	0.75	0.19	0.19	0.00
KY	0.79	0.89	0.90	0.90	0.00	0.78	0.91	0.90	0.90	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MDPA[a]	3.12	3.00	1.74	1.74	0.00	3.09	3.00	1.74	1.74	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.75	0.00	0.00	0.00	0.00	0.75	0.00	0.00	0.00	0.00
MN	2.41	2.25	0.00	0.00	0.00	2.41	2.25	0.00	0.00	0.00
MO	2.56	1.48	0.49	0.49	0.01	2.56	1.37	0.52	0.52	0.01
MT	1.07	1.12	0.42	0.36	0.00	1.07	1.07	0.42	0.36	0.00
NC	6.84	6.09	0.00	0.13	0.00	9.96	9.45	0.00	0.13	0.00
ND	1.01	1.08	0.26	0.26	0.01	1.06	1.01	0.26	0.26	0.01
NE	1.15	1.18	0.13	0.10	0.02	1.15	1.15	0.12	0.10	0.02
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.98	0.01	0.01	0.01	0.98	0.98	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.44	1.03	0.08	0.08	0.00	0.40	1.03	0.08	0.08	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.32	2.19	3.18	3.18	0.00	0.11	2.35	3.18	3.18	0.00

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
SD	0.87	1.33	0.00	0.00	0.00	0.87	1.33	0.00	0.00	0.00
TN	3.89	0.01	0.00	0.00	0.00	2.64	0.42	0.00	0.00	0.00
TX-reg[b]	3.67	3.38	1.77	1.76	0.10	3.46	3.03	1.52	1.52	0.06
UT	1.00	0.06	0.00	0.00	0.00	1.00	0.06	0.00	0.00	0.00
VA	0.65	0.45	0.01	0.01	0.00	0.65	0.45	0.01	0.01	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.65	2.14	0.00	0.00	0.00	1.65	0.64	0.01	0.01	0.00
WV	0.93	1.19	0.25	0.25	0.00	0.93	1.20	0.25	0.25	0.00
WY	1.22	1.12	0.57	0.29	0.07	1.22	0.99	0.57	0.28	0.06

Note: Emissions of Maryland, Arkansas, Kansas, Louisiana, Oklahoma, and Mississippi are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.

[a] MDPA: Maryland and Pennsylvania

[b] TX-reg: Arkansas, Kansas, Louisiana, Oklahoma, Mississippi, Texas

Table B-6 Baseline and Alternative 1 Scenario Ozone Scaling Factors for Natural Gas EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.53	0.61	0.49	0.39	0.27	0.52	0.50	0.50	0.41	0.31
AR	0.65	0.68	0.43	0.20	0.10	0.68	0.77	0.47	0.21	0.10
AZ	0.69	0.68	0.67	0.68	0.45	0.69	0.69	0.71	0.68	0.40
CA	0.92	0.94	0.85	0.52	0.02	0.95	0.94	1.36	0.53	0.02
CO	3.26	0.63	0.50	0.48	0.12	3.47	0.61	0.76	0.44	0.16
CT	1.04	0.98	0.89	0.00	0.01	1.05	1.00	0.92	0.00	0.01
DC	0.86	0.59	0.33	0.21	0.16	0.86	0.59	0.30	0.19	0.12
DE	0.79	0.80	0.38	0.37	0.38	0.81	0.81	0.59	0.37	0.37
FL	1.08	1.03	1.04	0.89	0.66	1.08	1.05	1.04	0.89	0.64
GA	0.58	0.54	0.52	0.42	0.38	0.57	0.55	0.52	0.42	0.38
IA	0.53	0.42	0.16	0.04	0.01	0.55	0.54	0.21	0.04	0.01
ID	0.60	0.90	0.90	0.90	0.04	0.68	1.00	0.45	0.54	0.04
IL	0.69	0.61	0.42	0.21	0.00	0.71	0.66	0.45	0.21	0.00
IN	0.75	0.63	0.38	0.20	0.15	0.78	0.67	0.44	0.21	0.16
KS	1.38	1.32	0.25	0.14	0.10	1.36	1.36	0.52	0.50	0.48
KY	0.87	0.81	0.69	0.57	0.38	0.89	0.85	0.67	0.58	0.44
LA	1.04	1.00	0.72	0.45	0.41	1.02	0.95	0.74	0.48	0.41
MA	0.60	0.67	0.66	0.84	0.47	0.58	0.67	0.68	0.84	0.44
MD	1.51	1.33	1.12	0.84	0.79	1.51	1.29	1.07	0.79	0.73
ME	1.16	1.15	0.59	0.63	0.36	1.16	1.15	0.74	0.65	0.36
MI	0.68	0.70	0.55	0.41	0.23	0.77	0.82	0.64	0.47	0.22

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
MN	0.92	0.84	0.34	0.17	0.13	0.92	0.93	0.38	0.20	0.08
MO	0.59	0.59	0.20	0.08	0.04	0.55	0.70	0.26	0.08	0.04
MS	0.64	0.62	0.50	0.45	0.29	0.64	0.62	0.50	0.45	0.28
MT	0.95	1.10	0.08	0.14	0.02	0.95	0.79	0.66	0.14	0.02
NC	0.77	0.59	0.68	0.63	0.51	0.77	0.58	0.71	0.73	0.61
ND	0.85	1.85	0.34	0.96	0.14	0.82	1.85	1.05	0.96	0.14
NE	5.91	5.92	0.28	0.87	0.02	5.90	6.46	8.17	6.07	4.85
NH	0.67	0.51	0.41	0.41	0.41	0.64	0.50	0.49	0.41	0.41
NJ	0.81	0.85	0.61	0.49	0.46	0.83	0.88	0.73	0.49	0.46
NM	1.00	0.84	0.77	0.35	0.47	0.98	0.82	0.66	0.29	0.61
NV	0.33	0.25	0.19	0.21	0.12	0.27	0.25	0.21	0.21	0.10
NY	1.03	0.99	0.65	0.28	0.28	1.04	0.99	0.63	0.28	0.28
OH	1.02	0.97	0.84	0.71	0.62	1.05	0.97	0.80	0.68	0.63
OK	1.69	1.57	0.48	0.33	0.32	1.63	1.60	0.66	0.49	0.48
OR	63.29	0.00	0.00	0.00	0.00	59.34	0.14	0.60	0.00	0.00
PA	0.79	0.69	0.34	0.24	0.23	0.91	0.69	0.36	0.23	0.23
RI	0.69	0.75	0.71	0.88	0.89	0.69	0.75	0.70	0.88	0.79
SC	0.93	0.96	0.59	0.59	0.56	0.94	0.96	0.58	0.54	0.53
SD	0.59	0.59	0.17	0.06	0.03	0.52	0.62	0.25	0.16	0.01
TN	1.12	1.09	1.07	0.90	0.51	1.18	1.08	1.02	0.91	0.50
TX	0.99	0.89	0.47	0.28	0.15	0.87	0.82	0.51	0.30	0.20
UT	0.50	0.43	0.34	0.37	0.31	0.50	0.42	0.32	0.35	0.29
VA	0.89	0.85	0.54	0.32	0.26	0.89	0.84	0.64	0.32	0.26
VT	0.00	0.37	3.53	3.99	0.00	0.00	0.37	3.53	3.99	0.00
WA	0.08	0.23	0.79	0.74	0.02	0.08	0.23	0.89	0.87	0.02
WI	0.74	0.70	0.58	0.30	0.14	0.73	0.86	0.68	0.31	0.18
WV	1.19	1.12	0.33	0.13	0.07	1.19	1.12	0.48	0.11	0.09
WY	0.01	0.04	0.06	0.06	0.00	0.01	0.03	0.35	0.17	0.00

Table B-7 Alternative 2 and Final Rules Scenario Ozone Scaling Factors for Natural Gas EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.53	0.61	0.50	0.41	0.31	0.53	0.50	0.50	0.41	0.31
AR	0.68	0.68	0.44	0.21	0.10	0.68	0.83	0.48	0.21	0.10
AZ	0.69	0.68	0.71	0.68	0.40	0.69	0.69	0.71	0.69	0.39
CA	0.95	0.94	1.39	0.53	0.02	0.94	0.94	1.58	0.54	0.02
CO	3.47	0.63	0.82	0.41	0.16	2.78	0.62	0.76	0.47	0.10

	Alternative 2					Final Rules				
State Tag	**2028**	**2030**	**2035**	**2040**	**2045**	**2028**	**2030**	**2035**	**2040**	**2045**
CT	1.04	0.99	0.92	0.00	0.01	1.05	1.00	0.92	0.00	0.01
DC	0.86	0.59	0.30	0.19	0.12	0.81	0.59	0.28	0.15	0.11
DE	0.81	0.80	0.61	0.37	0.37	0.80	0.81	0.68	0.37	0.37
FL	1.08	1.03	1.04	0.89	0.64	1.08	1.05	1.05	0.89	0.63
GA	0.58	0.54	0.52	0.43	0.38	0.58	0.55	0.52	0.43	0.38
IA	0.55	0.39	0.20	0.04	0.01	0.55	0.54	0.21	0.04	0.01
ID	0.67	0.98	0.45	0.53	0.04	0.65	0.95	0.22	0.29	0.04
IL	0.69	0.62	0.45	0.21	0.00	0.74	0.68	0.45	0.22	0.00
IN	0.76	0.63	0.45	0.21	0.16	0.78	0.68	0.48	0.21	0.16
KS	1.37	1.34	0.56	0.43	0.41	1.30	1.36	0.61	0.50	0.48
KY	0.89	0.83	0.67	0.58	0.43	0.92	0.86	0.65	0.59	0.44
LA	1.03	1.02	0.75	0.48	0.42	1.02	0.94	0.74	0.48	0.42
MA	0.57	0.67	0.67	0.84	0.44	0.58	0.67	0.66	0.85	0.44
MD	1.35	1.28	1.07	0.79	0.73	1.51	1.32	1.14	0.68	0.71
ME	1.16	1.15	0.76	0.65	0.36	1.16	1.15	0.83	0.64	0.36
MI	0.77	0.71	0.64	0.47	0.22	0.78	0.82	0.67	0.49	0.22
MN	0.85	0.76	0.37	0.20	0.08	1.00	1.00	0.37	0.20	0.08
MO	0.55	0.60	0.28	0.08	0.04	0.55	0.72	0.30	0.08	0.04
MS	0.75	0.61	0.50	0.46	0.28	0.64	0.61	0.50	0.46	0.28
MT	0.95	0.79	2.04	0.14	0.02	0.95	0.79	0.83	0.14	0.02
NC	0.77	0.60	0.71	0.73	0.61	0.77	0.60	0.69	0.69	0.68
ND	0.82	1.84	1.05	0.96	0.14	0.90	1.85	1.05	0.96	0.14
NE	5.91	5.95	8.85	6.09	5.12	5.90	6.55	8.24	6.07	4.85
NH	0.64	0.50	0.49	0.41	0.41	0.63	0.50	0.49	0.41	0.41
NJ	0.83	0.85	0.72	0.49	0.46	0.84	0.95	0.73	0.57	0.46
NM	0.98	0.82	0.66	0.29	0.61	0.98	0.82	0.66	0.27	0.50
NV	0.30	0.24	0.21	0.21	0.10	0.24	0.25	0.21	0.21	0.10
NY	1.03	0.98	0.64	0.28	0.28	1.05	1.01	0.64	0.28	0.28
OH	1.03	0.96	0.80	0.68	0.62	1.03	0.96	0.77	0.67	0.61
OK	1.64	1.54	0.66	0.48	0.47	1.63	1.58	0.67	0.49	0.48
OR	59.93	0.14	0.59	0.00	0.00	61.93	0.00	2.45	0.00	0.00
PA	0.91	0.69	0.36	0.23	0.23	0.91	0.69	0.36	0.24	0.23
RI	0.69	0.75	0.70	0.88	0.79	0.69	0.75	0.70	0.88	0.79
SC	0.94	0.97	0.58	0.55	0.53	0.95	0.95	0.59	0.55	0.54
SD	0.52	0.56	0.25	0.15	0.01	0.52	0.62	0.29	0.16	0.01
TN	1.16	1.09	1.02	0.91	0.50	1.21	1.09	1.02	0.93	0.50
TX	0.88	0.79	0.51	0.29	0.18	0.85	0.82	0.51	0.30	0.20
UT	0.50	0.42	0.32	0.35	0.29	0.50	0.41	0.32	0.35	0.28
VA	0.89	0.83	0.64	0.33	0.26	0.89	0.85	0.64	0.33	0.28
VT	0.00	0.37	3.53	3.99	0.00	0.00	0.37	3.53	3.99	0.00
WA	0.08	0.20	0.89	0.87	0.02	0.10	0.22	0.90	0.88	0.02

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
WI	0.73	0.64	0.68	0.31	0.18	0.74	0.87	0.68	0.31	0.18
WV	1.19	1.12	0.48	0.11	0.09	1.19	1.13	0.53	0.11	0.09
WY	0.01	0.01	0.35	0.15	0.00	0.02	0.03	0.33	0.17	0.00

Table B-8 Baseline and Alternative 1 Nitrate Scaling Factors for Coal EGU tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	1.33	1.45	1.65	1.54	0.14	1.31	1.45	1.60	1.60	0.00
AR	39.93	8.30	3.83	0.71	0.28	37.13	3.65	0.61	0.49	0.06
AZ	0.47	0.97	0.59	0.20	0.15	0.45	0.98	0.69	0.69	0.00
CA	0.24	0.36	0.16	0.13	0.00	0.24	0.43	0.02	0.01	0.00
CO	25.56	0.97	0.37	0.41	0.37	26.51	0.97	0.37	0.41	0.37
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.89	1.20	0.26	0.26	0.14	0.89	1.38	0.18	0.18	0.02
GA	0.23	0.12	0.00	0.00	0.00	0.22	0.26	0.00	0.00	0.00
IA	1.20	1.16	0.68	0.28	0.19	1.19	0.89	0.03	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.98	0.92	0.62	0.14	0.00	0.97	0.93	0.99	0.99	0.00
IN	1.29	0.64	0.11	0.11	0.00	1.20	0.59	0.11	0.11	0.00
KS	45.15	46.03	3.08	3.08	0.00	28.46	30.56	3.08	3.08	0.00
KY	1.38	1.12	1.15	1.00	0.07	1.25	1.10	1.11	1.11	0.00
LA	24.63	16.33	25.37	13.43	2.22	20.11	20.90	13.43	13.43	2.28
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	2.97	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.74	0.00	0.00	0.00	0.00	0.74	0.00	0.00	0.00	0.00
MN	2.97	2.31	0.00	0.00	0.00	2.93	2.34	0.00	0.00	0.00
MO	1.41	1.06	0.43	0.04	0.03	1.29	0.93	0.20	0.20	0.00
MS	4.02	3.60	1.06	1.00	1.00	1.94	3.60	8.15	8.15	0.00
MT	1.07	1.09	1.08	1.02	0.38	1.07	1.07	0.39	0.35	0.00
NC	19.19	11.95	3.66	3.51	3.84	15.57	12.43	0.07	0.07	0.07
ND	1.03	1.03	0.25	0.25	0.01	0.99	0.98	0.27	0.27	0.01
NE	1.14	1.13	0.61	0.37	0.18	1.12	1.11	0.11	0.09	0.01
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
NM	0.99	0.99	0.01	0.01	0.01	0.99	1.00	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.90	0.94	0.19	0.00	0.00	0.79	0.97	0.07	0.06	0.00
OK	12.10	5.08	3.11	3.11	1.03	9.02	4.41	0.14	0.14	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	3.05	2.94	2.61	1.19	1.16	2.96	2.90	1.60	1.60	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	1.15	1.92	2.98	2.98	0.00	0.78	1.90	2.98	2.98	0.00
SD	0.93	1.11	0.00	0.00	0.00	0.91	1.11	0.00	0.00	0.00
TN	7.49	1.00	0.00	0.00	0.00	6.21	1.10	0.00	0.00	0.00
TX	1.02	1.13	0.87	0.47	0.12	0.77	0.73	0.81	0.81	0.01
UT	3.50	0.09	0.09	0.09	0.06	3.50	0.09	0.00	0.00	0.00
VA	0.67	0.41	0.12	0.00	0.00	0.67	0.41	0.01	0.01	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.84	2.07	0.38	0.00	0.00	1.77	0.56	0.01	0.01	0.00
WV	1.25	1.30	0.97	0.27	0.09	1.23	1.34	0.26	0.26	0.00
WY	1.32	1.15	1.14	0.61	0.48	1.29	1.03	0.56	0.29	0.06

Table B-9 Alternative 2 and Final Rules Nitrate Scaling Factors for Coal EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	1.32	1.45	1.60	1.60	0.00	1.32	1.45	1.60	1.60	0.00
AR	37.33	8.25	0.61	0.49	0.06	36.19	3.65	0.61	0.49	0.06
AZ	0.45	0.97	0.70	0.70	0.00	0.46	0.98	0.69	0.69	0.00
CA	0.24	0.36	0.02	0.01	0.00	0.24	0.43	0.02	0.01	0.00
CO	26.20	0.97	0.37	0.41	0.37	26.75	0.97	0.40	0.40	0.37
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.89	1.20	0.18	0.18	0.02	0.89	1.38	0.18	0.18	0.02
GA	0.22	0.11	0.00	0.00	0.00	0.17	0.21	0.00	0.00	0.00
IA	1.19	1.15	0.13	0.00	0.00	1.19	0.89	0.03	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	0.97	0.93	0.99	0.99	0.00	0.97	0.93	0.99	0.99	0.00
IN	1.23	0.65	0.11	0.11	0.00	1.20	0.59	0.11	0.11	0.00
KS	28.47	29.33	3.08	3.08	0.00	27.03	29.44	3.08	3.08	0.00
KY	1.25	1.05	1.11	1.11	0.00	1.22	1.09	1.11	1.11	0.00

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
LA	20.21	14.07	13.43	13.43	2.28	20.85	20.42	13.43	13.43	2.28
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	0.00	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.74	0.00	0.00	0.00	0.00	0.74	0.00	0.00	0.00	0.00
MN	2.95	2.29	0.00	0.00	0.00	2.91	2.36	0.00	0.00	0.00
MO	1.29	0.96	0.19	0.19	0.00	1.29	0.93	0.20	0.20	0.00
MS	1.94	3.60	8.15	8.15	0.00	1.94	3.60	8.15	8.15	0.00
MT	1.07	1.09	0.39	0.35	0.00	1.07	1.07	0.39	0.35	0.00
NC	13.93	10.44	0.07	0.07	0.07	17.53	12.83	0.07	0.07	0.07
ND	1.00	1.02	0.27	0.27	0.01	1.01	0.98	0.27	0.27	0.01
NE	1.12	1.13	0.12	0.09	0.01	1.12	1.10	0.11	0.09	0.01
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.99	0.99	0.01	0.01	0.01	0.99	1.00	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.83	0.94	0.07	0.06	0.00	0.81	0.95	0.07	0.06	0.00
OK	9.55	5.09	2.08	2.08	0.00	5.42	4.41	0.14	0.14	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	2.96	2.90	1.60	1.60	0.00	2.96	2.90	1.60	1.60	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.92	1.79	2.98	2.98	0.00	0.78	1.90	2.98	2.98	0.00
SD	0.91	1.06	0.00	0.00	0.00	0.91	1.07	0.00	0.00	0.00
TN	7.49	1.00	0.00	0.00	0.00	5.40	1.00	0.00	0.00	0.00
TX	0.91	0.98	0.96	0.96	0.03	0.76	0.73	0.81	0.81	0.01
UT	3.50	0.09	0.00	0.00	0.00	3.50	0.09	0.00	0.00	0.00
VA	0.67	0.48	0.01	0.01	0.00	0.67	0.34	0.01	0.01	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	1.77	2.03	0.00	0.00	0.00	1.77	0.56	0.01	0.01	0.00
WV	1.24	1.32	0.26	0.26	0.00	1.22	1.34	0.26	0.26	0.00
WY	1.29	1.14	0.56	0.30	0.07	1.29	1.04	0.56	0.29	0.06

Table B-10 Baseline and Alternative 1 Nitrate Scaling Factors for Natural Gas EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.59	0.60	0.45	0.27	0.16	0.58	0.54	0.46	0.28	0.19

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AR	0.56	0.68	0.38	0.13	0.06	0.58	0.78	0.41	0.14	0.06
AZ	0.73	0.85	0.83	0.75	0.37	0.72	0.82	0.86	0.74	0.35
CA	0.76	0.88	0.97	0.67	0.16	0.77	0.89	1.15	0.67	0.16
CO	2.02	0.71	0.72	0.76	0.30	2.10	0.73	0.93	0.72	0.42
CT	0.92	0.81	0.66	0.00	0.01	0.91	0.82	0.66	0.00	0.01
DC	0.63	0.47	0.26	0.18	0.13	0.62	0.47	0.19	0.13	0.10
DE	0.79	0.76	0.33	0.29	0.30	0.79	0.78	0.53	0.29	0.30
FL	1.11	1.06	1.01	0.73	0.49	1.11	1.06	1.00	0.77	0.48
GA	0.68	0.63	0.54	0.29	0.22	0.67	0.63	0.54	0.30	0.23
IA	0.49	0.42	0.13	0.03	0.01	0.50	0.55	0.19	0.03	0.01
ID	1.02	1.36	1.39	1.24	0.60	1.17	1.53	1.10	1.06	0.71
IL	0.54	0.54	0.29	0.12	0.00	0.55	0.61	0.34	0.13	0.00
IN	0.67	0.59	0.34	0.12	0.08	0.67	0.61	0.39	0.12	0.09
KS	0.96	0.87	0.20	0.07	0.05	0.95	0.96	0.37	0.27	0.26
KY	0.81	0.76	0.46	0.25	0.15	0.84	0.78	0.42	0.24	0.17
LA	0.96	0.94	0.61	0.27	0.24	0.94	0.98	0.62	0.28	0.24
MA	0.64	0.66	0.54	0.61	0.33	0.62	0.66	0.54	0.60	0.32
MD	1.47	1.35	1.05	0.72	0.66	1.46	1.33	0.93	0.59	0.61
ME	1.64	1.34	0.63	0.58	0.34	1.56	1.31	0.80	0.58	0.34
MI	0.65	0.71	0.43	0.30	0.15	0.71	0.80	0.56	0.32	0.15
MN	1.02	0.95	0.36	0.15	0.09	1.01	1.07	0.38	0.16	0.06
MO	0.52	0.52	0.19	0.06	0.03	0.49	0.63	0.26	0.06	0.03
MS	0.61	0.56	0.36	0.24	0.15	0.61	0.56	0.41	0.24	0.14
MT	0.66	0.80	0.05	0.08	0.01	0.66	0.64	0.41	0.08	0.01
NC	0.89	0.67	0.72	0.55	0.47	0.89	0.69	0.77	0.64	0.54
ND	0.66	1.32	0.26	0.60	0.09	0.65	1.47	1.01	0.60	0.09
NE	2.05	1.80	0.13	0.31	0.01	2.06	2.01	2.46	1.72	1.31
NH	0.78	0.59	0.44	0.38	0.36	0.76	0.58	0.49	0.38	0.36
NJ	0.82	0.83	0.51	0.34	0.39	0.83	0.85	0.61	0.35	0.39
NM	0.74	0.66	0.64	0.33	0.39	0.73	0.65	0.58	0.29	0.41
NV	0.50	0.39	0.44	0.40	0.23	0.46	0.35	0.46	0.39	0.23
NY	0.91	0.89	0.55	0.16	0.16	0.93	0.88	0.56	0.16	0.16
OH	1.00	0.98	0.87	0.59	0.42	1.01	0.98	0.80	0.55	0.40
OK	1.43	1.20	0.34	0.21	0.20	1.32	1.27	0.49	0.31	0.31
OR	5.58	0.96	0.50	0.00	0.00	5.45	0.95	0.48	0.00	0.00
PA	0.69	0.61	0.35	0.21	0.18	0.75	0.61	0.36	0.21	0.18
RI	0.76	0.76	0.64	0.71	0.68	0.76	0.76	0.61	0.71	0.61
SC	0.94	0.96	0.67	0.56	0.55	0.92	1.02	0.68	0.55	0.55
SD	0.55	0.55	0.16	0.06	0.04	0.50	0.59	0.29	0.16	0.01
TN	1.02	0.97	0.79	0.41	0.23	1.04	0.96	0.77	0.42	0.22
TX	0.97	0.88	0.42	0.17	0.08	0.84	0.79	0.47	0.19	0.11

	Baseline					Alternative 1				
State Tag	**2028**	**2030**	**2035**	**2040**	**2045**	**2028**	**2030**	**2035**	**2040**	**2045**
UT	0.52	0.62	0.56	0.58	0.46	0.52	0.59	0.53	0.53	0.43
VA	0.84	0.80	0.43	0.20	0.15	0.84	0.77	0.53	0.20	0.15
VT	0.10	0.16	1.53	1.73	0.00	0.10	0.16	1.53	1.73	0.00
WA	0.43	0.36	0.72	0.97	0.44	0.44	0.35	0.71	0.75	0.46
WI	0.66	0.67	0.45	0.18	0.08	0.65	0.81	0.56	0.19	0.11
WV	1.02	0.89	0.22	0.08	0.04	1.03	0.91	0.31	0.07	0.06
WY	0.01	0.04	0.06	0.06	0.00	0.01	0.03	0.35	0.16	0.00

Table B-11 Alternative 2 and Final Rules Nitrate Scaling Factors for Natural Gas EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.59	0.60	0.46	0.28	0.19	0.59	0.54	0.47	0.29	0.19
AR	0.58	0.67	0.39	0.14	0.06	0.59	0.82	0.41	0.14	0.06
AZ	0.72	0.81	0.86	0.74	0.35	0.73	0.85	0.86	0.76	0.35
CA	0.77	0.89	1.17	0.67	0.16	0.76	0.89	1.40	0.66	0.16
CO	2.10	0.73	0.96	0.71	0.42	1.75	0.74	0.93	0.80	0.39
CT	0.91	0.81	0.66	0.00	0.01	0.91	0.83	0.66	0.00	0.01
DC	0.62	0.47	0.19	0.13	0.10	0.60	0.47	0.17	0.11	0.08
DE	0.79	0.77	0.54	0.29	0.30	0.80	0.80	0.60	0.29	0.30
FL	1.11	1.06	1.00	0.77	0.48	1.11	1.06	1.00	0.78	0.48
GA	0.68	0.63	0.55	0.31	0.23	0.68	0.62	0.55	0.31	0.23
IA	0.50	0.40	0.18	0.03	0.01	0.51	0.55	0.19	0.03	0.01
ID	1.17	1.51	1.11	1.05	0.71	1.12	1.42	0.93	0.80	0.63
IL	0.54	0.55	0.34	0.13	0.00	0.58	0.62	0.34	0.13	0.00
IN	0.67	0.58	0.40	0.12	0.09	0.68	0.62	0.43	0.13	0.09
KS	0.96	0.92	0.39	0.23	0.22	0.92	0.97	0.41	0.27	0.26
KY	0.84	0.77	0.42	0.24	0.17	0.85	0.78	0.40	0.25	0.17
LA	0.96	0.95	0.62	0.29	0.24	0.95	0.98	0.62	0.28	0.24
MA	0.61	0.66	0.54	0.60	0.32	0.62	0.66	0.53	0.61	0.32
MD	1.37	1.33	0.93	0.59	0.61	1.47	1.35	0.94	0.53	0.56
ME	1.56	1.29	0.81	0.58	0.34	1.56	1.30	0.88	0.59	0.34
MI	0.71	0.73	0.56	0.32	0.15	0.72	0.79	0.59	0.33	0.15
MN	0.96	0.89	0.38	0.16	0.06	1.08	1.14	0.38	0.16	0.06
MO	0.49	0.53	0.28	0.06	0.03	0.50	0.65	0.29	0.06	0.03
MS	0.66	0.55	0.41	0.24	0.14	0.62	0.56	0.41	0.24	0.14
MT	0.66	0.62	1.24	0.08	0.01	0.68	0.64	0.50	0.08	0.01
NC	0.90	0.68	0.77	0.63	0.54	0.89	0.70	0.74	0.63	0.57
ND	0.65	1.33	1.11	0.60	0.09	0.83	1.47	0.89	0.60	0.09
NE	2.06	1.82	2.65	1.73	1.39	2.06	2.09	2.48	1.72	1.31
NH	0.75	0.58	0.49	0.38	0.36	0.74	0.58	0.50	0.38	0.36
NJ	0.83	0.83	0.61	0.35	0.39	0.84	0.89	0.62	0.39	0.39
NM	0.73	0.64	0.58	0.29	0.41	0.72	0.65	0.58	0.28	0.41
NV	0.48	0.35	0.46	0.39	0.23	0.44	0.40	0.46	0.39	0.23
NY	0.92	0.88	0.57	0.16	0.16	0.92	0.90	0.57	0.16	0.16
OH	0.99	0.97	0.80	0.55	0.40	1.00	0.96	0.77	0.53	0.38
OK	1.34	1.18	0.49	0.30	0.30	1.30	1.28	0.50	0.31	0.31
OR	5.46	0.96	0.50	0.00	0.00	5.53	0.96	0.50	0.00	0.00
PA	0.76	0.61	0.36	0.21	0.18	0.77	0.61	0.36	0.22	0.18
RI	0.76	0.76	0.61	0.71	0.61	0.76	0.76	0.61	0.71	0.61
SC	0.93	0.98	0.67	0.55	0.55	0.92	1.02	0.68	0.53	0.55

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
SD	0.50	0.53	0.29	0.16	0.01	0.49	0.59	0.32	0.16	0.01
TN	1.03	0.96	0.78	0.42	0.22	1.06	0.96	0.78	0.43	0.22
TX	0.85	0.76	0.46	0.18	0.10	0.83	0.79	0.47	0.19	0.11
UT	0.52	0.59	0.53	0.53	0.43	0.52	0.59	0.53	0.53	0.42
VA	0.84	0.77	0.54	0.21	0.15	0.85	0.80	0.55	0.21	0.16
VT	0.10	0.16	1.53	1.73	0.00	0.10	0.16	1.53	1.73	0.00
WA	0.44	0.36	0.72	0.75	0.46	0.45	0.35	0.68	0.75	0.41
WI	0.64	0.63	0.57	0.18	0.11	0.66	0.81	0.57	0.19	0.11
WV	1.03	0.90	0.31	0.07	0.06	1.04	0.92	0.34	0.07	0.06
WY	0.01	0.01	0.34	0.14	0.00	0.02	0.03	0.35	0.17	0.00

Table B-12 Baseline and Alternative 1 Sulfate Scaling Factors for Coal EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	4.96	5.39	7.07	5.96	0.34	4.92	5.39	6.66	6.43	0.00
AR	118.10	7.02	4.45	1.09	0.42	110.71	0.84	1.04	0.66	0.00
AZ	0.48	1.42	1.16	0.32	0.31	0.50	1.44	0.95	0.41	0.00
CA	0.33	0.50	0.26	0.19	0.00	0.33	0.57	0.11	0.07	0.00
CO	14.31	0.98	0.20	0.22	0.21	15.56	0.98	0.20	0.22	0.21
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.98	1.16	0.50	0.50	0.38	0.98	1.27	0.50	0.50	0.00
GA	0.04	0.09	0.00	0.00	0.00	0.14	0.19	0.00	0.00	0.00
IA	1.31	1.25	0.78	0.32	0.21	1.29	0.81	0.03	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.01	0.73	0.48	0.10	0.00	1.01	0.74	0.78	0.78	0.00
IN	0.89	0.56	0.12	0.13	0.00	0.82	0.60	0.12	0.14	0.00
KS	52.35	51.92	11.39	11.39	0.00	35.24	37.81	11.39	11.39	0.00
KY	2.68	2.12	1.88	1.71	0.09	2.43	2.11	1.82	1.82	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	2.97	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.85	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.00
MN	1.68	1.47	0.00	0.00	0.00	1.66	1.49	0.00	0.00	0.00
MO	2.20	1.08	0.71	0.10	0.12	2.07	0.98	0.07	0.07	0.00
MS	4.02	3.60	1.06	1.00	1.00	1.94	3.60	8.15	8.15	0.00
MT	1.85	2.06	1.92	1.30	0.39	1.85	1.72	1.29	0.91	0.00
NC	7.31	5.14	1.88	1.67	2.03	6.20	4.30	0.00	0.00	0.00

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
ND	0.94	1.00	0.94	0.93	0.03	0.91	0.98	1.16	1.16	0.03
NE	0.96	0.95	0.58	0.35	0.18	0.95	0.94	0.05	0.04	0.00
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	1.00	1.00	0.01	0.01	0.01	1.00	1.00	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.78	0.61	0.29	0.00	0.00	0.68	0.70	0.04	0.02	0.00
OK	37.84	4.77	2.54	2.54	1.68	36.50	4.32	0.11	0.11	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	4.25	4.06	3.94	1.63	1.83	4.20	4.11	1.79	1.79	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.73	1.22	1.76	1.76	0.00	0.54	1.26	1.76	1.76	0.00
SD	1.05	1.27	0.00	0.00	0.00	1.08	1.27	0.00	0.00	0.00
TN	20.55	1.57	0.00	0.00	0.00	15.91	1.72	0.00	0.00	0.00
TXLA[a]	1.86	2.39	2.25	1.61	0.42	1.23	1.96	1.76	1.71	0.24
UT	0.93	0.06	0.06	0.05	0.04	0.95	0.06	0.00	0.00	0.00
VA	0.11	0.07	0.02	0.00	0.00	0.11	0.07	0.00	0.00	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	3.50	3.83	1.15	0.00	0.00	3.37	0.95	0.01	0.01	0.00
WV	1.40	1.39	1.08	0.36	0.12	1.30	1.52	0.31	0.31	0.00
WY	1.26	0.98	0.97	0.49	0.37	1.22	0.89	0.85	0.45	0.11

Note: Emissions of Louisiana are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from Texas and Louisiana were combined.

[a] TXLA: Louisiana and Texas

Table B-13 Alternative 2 and Final Rules Sulfate Scaling Factors for Coal EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	4.94	5.39	6.66	6.63	0.00	4.94	5.39	6.66	6.63	0.00
AR	111.33	6.92	1.04	0.66	0.00	107.76	0.84	1.04	0.66	0.00
AZ	0.50	1.42	0.96	0.41	0.00	0.50	1.44	0.95	0.41	0.00
CA	0.33	0.50	0.11	0.07	0.00	0.33	0.57	0.11	0.07	0.00
CO	15.29	0.98	0.20	0.22	0.21	15.78	0.98	0.21	0.21	0.21
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.98	1.15	0.50	0.50	0.00	0.98	1.26	0.50	0.50	0.00
GA	0.04	0.09	0.00	0.00	0.00	0.05	0.12	0.00	0.00	0.00

	Alternative 2					**Final Rules**				
State Tag	**2028**	**2030**	**2035**	**2040**	**2045**	**2028**	**2030**	**2035**	**2040**	**2045**
IA	1.29	1.23	0.09	0.00	0.00	1.29	0.81	0.03	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.01	0.74	0.78	0.78	0.00	1.01	0.74	0.78	0.78	0.00
IN	0.85	0.56	0.12	0.14	0.00	0.82	0.60	0.12	0.14	0.00
KS	35.29	36.29	11.39	11.39	0.00	33.52	36.70	11.39	11.39	0.00
KY	2.44	2.06	1.82	1.82	0.00	2.39	2.10	1.82	1.82	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	0.00	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.85	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.00
MN	1.67	1.45	0.00	0.00	0.00	1.64	1.50	0.00	0.00	0.00
MO	2.07	0.99	0.06	0.06	0.00	2.07	0.98	0.07	0.07	0.00
MS	1.94	3.60	8.15	8.15	0.00	1.94	3.60	8.15	8.15	0.00
MT	1.85	2.06	1.29	0.91	0.00	1.81	1.73	1.29	0.91	0.00
NC	5.56	4.46	0.00	0.00	0.00	6.82	4.32	0.00	0.00	0.00
ND	0.91	1.00	0.95	0.95	0.02	0.93	0.97	1.16	1.16	0.03
NE	0.95	0.95	0.05	0.04	0.00	0.94	0.94	0.05	0.04	0.00
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	1.00	1.00	0.01	0.01	0.01	1.00	1.00	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.71	0.65	0.04	0.02	0.00	0.73	0.59	0.04	0.02	0.00
OK	27.70	4.78	1.51	1.51	0.00	18.72	4.32	0.11	0.11	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	4.20	4.11	1.79	1.79	0.00	4.21	4.11	1.79	1.79	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.61	1.15	1.76	1.76	0.00	0.54	1.26	1.76	1.76	0.00
SD	1.08	1.21	0.00	0.00	0.00	1.08	1.22	0.00	0.00	0.00
TN	20.55	1.57	0.00	0.00	0.00	13.24	1.57	0.00	0.00	0.00
TXLA[a]	1.25	1.46	1.82	1.77	0.24	1.21	1.92	1.76	1.71	0.24
UT	0.95	0.06	0.00	0.00	0.00	0.95	0.06	0.00	0.00	0.00
VA	0.11	0.08	0.00	0.00	0.00	0.11	0.06	0.00	0.00	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	3.37	3.77	0.00	0.00	0.00	3.37	0.95	0.01	0.01	0.00
WV	1.31	1.49	0.31	0.31	0.00	1.29	1.50	0.31	0.31	0.00
WY	1.22	0.97	0.83	0.47	0.13	1.22	0.90	0.85	0.45	0.12

Note: Emissions of Louisiana are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from Texas and Louisiana were combined.

[a] TXLA: Louisiana and Texas

Table B-14 Baseline and Alternative 1 Primary $PM_{2.5}$ Scaling Factors for Coal EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	1.20	1.31	1.43	1.33	0.14	1.18	1.31	1.38	1.38	0.00
AR	20.02	7.10	3.14	0.08	0.03	18.77	3.64	0.11	0.05	0.01
AZ	0.38	1.17	0.61	0.18	0.16	0.36	1.20	0.77	0.77	0.00
CA	0.24	0.36	0.16	0.13	0.00	0.24	0.43	0.01	0.01	0.00
CO	13.37	1.19	0.51	0.54	0.51	15.57	1.19	0.51	0.54	0.51
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	1.40	1.84	0.25	0.25	0.13	1.40	2.10	0.17	0.17	0.02
GA	0.03	0.06	0.00	0.00	0.00	0.13	0.16	0.00	0.00	0.00
IA	1.17	1.14	0.67	0.28	0.19	1.16	0.79	0.04	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.17	0.95	0.57	0.03	0.00	1.16	0.96	0.98	0.98	0.00
IN	1.28	0.60	0.20	0.20	0.00	1.17	0.62	0.20	0.20	0.00
KY	1.30	1.19	0.77	0.36	0.16	1.25	1.17	0.50	0.50	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	2.97	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.83	0.00	0.00	0.00	0.00	0.83	0.00	0.00	0.00	0.00
MN	3.50	2.70	0.00	0.00	0.00	3.47	2.73	0.00	0.00	0.00
MO	3.04	1.33	0.54	0.11	0.10	2.85	1.17	0.51	0.51	0.00
MS	4.02	3.60	1.06	1.00	1.00	1.94	3.60	8.15	8.15	0.00
MT	0.98	0.98	0.98	0.98	0.38	0.98	0.98	0.99	0.99	0.00
NC	21.57	17.32	6.08	6.14	6.26	18.03	16.39	0.08	0.08	0.08
ND	0.94	0.98	0.78	0.72	0.04	0.92	0.95	0.86	0.86	0.04
NEKS[a]	3.70	3.68	0.80	0.50	0.15	3.03	3.03	0.35	0.33	0.01
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.99	0.01	0.01	0.01	0.98	0.99	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.83	1.08	0.19	0.00	0.00	0.71	1.10	0.21	0.21	0.00
OK	14.75	8.14	8.94	8.94	1.00	10.35	4.39	0.55	0.55	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	3.12	3.04	2.28	1.14	1.14	3.12	2.89	0.91	0.91	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	1.03	2.17	3.78	3.78	0.00	0.76	2.10	3.78	3.78	0.00

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
SD	0.93	1.11	0.00	0.00	0.00	0.91	1.11	0.00	0.00	0.00
TN	16.88	1.00	0.00	0.00	0.00	13.75	1.10	0.00	0.00	0.00
TXLA[b]	1.10	1.30	1.15	0.65	0.14	0.88	0.88	0.92	0.92	0.02
UT	2.92	0.06	0.06	0.06	0.04	2.86	0.06	0.00	0.00	0.00
VA	0.46	0.29	0.08	0.00	0.00	0.46	0.29	0.00	0.00	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	2.11	2.36	0.46	0.00	0.00	2.04	0.75	0.01	0.01	0.00
WV	1.29	1.45	1.23	0.56	0.06	1.29	1.50	0.53	0.53	0.00
WY	1.03	1.10	1.08	0.54	0.44	0.96	1.01	0.86	0.42	0.20

Note: Emissions of Louisiana and Kansas are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.

[a] NEKS: Nebraska and Kansas

[b] TXLA: Louisiana and Texas

Table B-15 Alternative 2 and Final Rules Primary $PM_{2.5}$ Scaling Factors for Coal EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	1.19	1.31	1.38	1.38	0.00	1.19	1.31	1.38	1.38	0.00
AR	18.82	7.05	0.11	0.05	0.01	18.31	3.64	0.11	0.05	0.01
AZ	0.36	1.17	0.78	0.78	0.00	0.36	1.20	0.77	0.77	0.00
CA	0.24	0.36	0.01	0.01	0.00	0.24	0.43	0.01	0.01	0.00
CO	15.10	1.19	0.51	0.54	0.51	15.92	1.19	0.53	0.53	0.51
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	1.40	1.84	0.17	0.17	0.02	1.40	2.09	0.17	0.17	0.02
GA	0.02	0.05	0.00	0.00	0.00	0.03	0.06	0.00	0.00	0.00
IA	1.16	1.13	0.12	0.00	0.00	1.16	0.79	0.04	0.00	0.00
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	1.16	0.96	0.98	0.98	0.00	1.16	0.96	0.98	0.98	0.00
IN	1.22	0.60	0.20	0.20	0.00	1.17	0.62	0.20	0.20	0.00
KY	1.23	1.11	0.49	0.49	0.00	1.20	1.16	0.50	0.50	0.00
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	3.54	3.54	3.54	3.54	0.00	3.54	3.57	3.57	3.57	0.00
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	0.83	0.00	0.00	0.00	0.00	0.83	0.00	0.00	0.00	0.00
MN	3.48	2.66	0.00	0.00	0.00	3.44	2.75	0.00	0.00	0.00
MO	2.85	1.23	0.49	0.49	0.01	2.85	1.16	0.51	0.51	0.00

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
MS	1.94	3.60	8.15	8.15	0.00	1.94	3.60	8.15	8.15	0.00
MT	0.98	0.98	0.99	0.99	0.00	0.98	0.98	0.99	0.99	0.00
NC	18.20	15.92	0.08	0.08	0.08	19.37	16.16	0.08	0.08	0.08
ND	0.92	0.97	0.77	0.77	0.04	0.94	0.94	0.86	0.86	0.04
NEKS[a]	2.99	3.02	0.36	0.33	0.01	2.89	2.92	0.35	0.33	0.01
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.98	0.99	0.01	0.01	0.01	0.98	0.99	0.01	0.01	0.01
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.76	1.05	0.21	0.21	0.00	0.74	1.05	0.21	0.21	0.00
OK	11.88	8.19	7.94	7.94	0.00	6.11	4.39	0.55	0.55	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	3.06	2.92	0.91	0.91	0.00	2.97	2.93	0.91	0.91	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.86	2.06	3.78	3.78	0.00	0.76	2.10	3.78	3.78	0.00
SD	0.91	1.06	0.00	0.00	0.00	0.91	1.07	0.00	0.00	0.00
TN	16.88	1.00	0.00	0.00	0.00	11.76	1.00	0.00	0.00	0.00
TXLA[b]	0.96	1.02	1.20	1.20	0.03	0.88	0.88	0.92	0.92	0.02
UT	2.86	0.06	0.00	0.00	0.00	2.86	0.06	0.00	0.00	0.00
VA	0.46	0.33	0.00	0.00	0.00	0.46	0.23	0.00	0.00	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	2.04	2.30	0.00	0.00	0.00	2.04	0.75	0.01	0.01	0.00
WV	1.29	1.47	0.52	0.52	0.00	1.26	1.49	0.53	0.53	0.00
WY	0.96	1.09	0.87	0.46	0.24	0.97	1.02	0.86	0.42	0.20

Note: Emissions of Louisiana and Kansas are less 10 tpy in the original source apportionment modeling. Air quality impacts and emissions from those states were combined with nearby states.

[a] NEKS: Nebraska and Kansas

[b] TXLA: Louisiana and Texas

Table B-16 Baseline and Alternative 1 Primary $PM_{2.5}$ Scaling Factors for Natural Gas EGU Tags

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.85	0.84	0.71	0.46	0.31	0.85	0.82	0.73	0.47	0.34
AR	0.63	0.82	0.43	0.10	0.07	0.66	0.86	0.47	0.10	0.07
AZ	0.70	0.85	0.86	0.74	0.39	0.69	0.82	0.92	0.73	0.34
CA	0.96	1.06	0.98	0.77	0.20	0.97	1.08	1.01	0.77	0.20

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
CO	1.23	0.74	0.77	0.75	0.32	1.21	0.75	0.88	0.67	0.39
CT	0.78	0.67	0.60	0.00	0.00	0.77	0.68	0.57	0.00	0.00
DC	0.15	0.13	0.11	0.10	0.08	0.15	0.13	0.07	0.07	0.07
DE	0.62	0.64	0.31	0.27	0.30	0.65	0.65	0.47	0.26	0.29
FL	0.97	0.98	0.95	0.77	0.55	0.97	0.98	0.94	0.78	0.54
GA	0.84	0.81	0.72	0.41	0.30	0.84	0.80	0.74	0.43	0.32
IA	0.50	0.48	0.20	0.06	0.01	0.52	0.65	0.38	0.07	0.02
ID	1.22	1.65	1.68	1.49	0.76	1.39	1.84	1.42	1.35	0.88
IL	0.49	0.55	0.28	0.13	0.00	0.50	0.61	0.37	0.14	0.00
IN	0.67	0.67	0.44	0.15	0.10	0.68	0.68	0.50	0.16	0.11
KS	1.11	1.01	0.19	0.08	0.04	1.10	1.09	0.45	0.33	0.31
KY	0.75	0.72	0.49	0.34	0.18	0.79	0.77	0.44	0.34	0.21
LA	0.79	0.80	0.64	0.29	0.19	0.78	0.79	0.68	0.30	0.19
MA	0.48	0.46	0.34	0.28	0.19	0.47	0.46	0.34	0.28	0.18
MD	1.05	1.08	0.85	0.63	0.61	1.05	1.04	0.86	0.54	0.59
ME	1.75	1.44	0.51	0.50	0.29	1.68	1.43	0.74	0.51	0.29
MI	0.75	0.87	0.63	0.48	0.28	0.79	0.86	0.68	0.46	0.27
MN	0.57	0.52	0.21	0.08	0.05	0.57	0.61	0.21	0.08	0.03
MO	0.30	0.33	0.10	0.03	0.01	0.27	0.44	0.18	0.02	0.01
MS	0.88	0.84	0.51	0.32	0.18	0.88	0.83	0.60	0.32	0.18
MT	0.17	0.21	0.03	0.03	0.00	0.17	0.18	0.47	0.03	0.00
NC	0.87	0.70	0.76	0.60	0.55	0.89	0.73	0.77	0.67	0.64
ND	0.47	0.92	0.19	0.43	0.06	0.46	1.02	0.68	0.43	0.06
NE	2.35	2.21	0.30	0.78	0.01	2.36	2.66	2.64	2.31	1.49
NH	0.59	0.43	0.31	0.27	0.25	0.57	0.42	0.36	0.27	0.25
NJ	0.82	0.84	0.52	0.40	0.42	0.82	0.85	0.67	0.41	0.41
NM	0.52	0.52	0.89	0.99	0.86	0.52	0.52	0.83	0.87	0.99
NV	0.72	0.84	0.83	0.85	0.36	0.70	0.80	0.87	0.84	0.37
NY	0.86	0.85	0.59	0.26	0.27	0.87	0.85	0.60	0.26	0.27
OH	0.95	0.95	0.89	0.63	0.42	0.96	0.95	0.85	0.59	0.41
OK	1.00	0.79	0.22	0.07	0.06	0.93	0.89	0.30	0.07	0.07
OR	3.29	0.74	0.39	0.00	0.00	3.24	0.72	0.37	0.00	0.00
PA	0.83	0.80	0.60	0.37	0.33	0.85	0.81	0.63	0.37	0.33
RI	0.83	0.78	0.65	0.38	0.35	0.83	0.79	0.61	0.38	0.33
SC	0.80	0.86	0.64	0.51	0.53	0.81	0.90	0.67	0.52	0.54
SD	0.73	0.73	0.25	0.13	0.11	0.70	0.89	0.41	0.26	0.02
TN	1.08	1.05	0.88	0.46	0.26	1.10	1.05	0.87	0.47	0.26
TX	0.90	0.83	0.45	0.19	0.09	0.81	0.77	0.50	0.20	0.10
UT	0.66	0.87	0.84	0.88	0.69	0.66	0.84	0.79	0.85	0.65
VA	0.81	0.73	0.47	0.26	0.17	0.82	0.72	0.60	0.27	0.18
VT	0.00	0.00	0.03	0.03	0.00	0.00	0.00	0.03	0.03	0.00

	Baseline					Alternative 1				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
WA	0.44	0.48	0.58	0.59	0.39	0.44	0.48	0.56	0.61	0.39
WI	0.56	0.66	0.43	0.18	0.08	0.55	0.78	0.52	0.19	0.11
WV	0.51	0.38	0.10	0.12	0.09	0.50	0.38	0.33	0.10	0.12
WY	0.01	0.04	0.03	0.03	0.00	0.01	0.01	1.32	0.49	0.00

Table B-17 Alternative 2 and Final Rules Primary $PM_{2.5}$ Scaling Factors for Natural Gas EGU Tags

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
AL	0.85	0.84	0.73	0.47	0.34	0.85	0.82	0.74	0.47	0.34
AR	0.66	0.82	0.47	0.10	0.07	0.68	0.87	0.48	0.10	0.08
AZ	0.69	0.81	0.92	0.74	0.34	0.70	0.84	0.93	0.76	0.34
CA	0.97	1.07	1.01	0.77	0.20	0.97	1.08	1.07	0.78	0.20
CO	1.22	0.76	0.90	0.67	0.39	1.06	0.75	0.86	0.67	0.36
CT	0.76	0.67	0.57	0.00	0.00	0.77	0.69	0.57	0.00	0.00
DC	0.15	0.13	0.07	0.07	0.07	0.14	0.13	0.06	0.05	0.05
DE	0.65	0.64	0.48	0.26	0.29	0.65	0.66	0.50	0.27	0.29
FL	0.97	0.98	0.94	0.78	0.54	0.97	0.98	0.94	0.79	0.54
GA	0.84	0.80	0.74	0.43	0.32	0.84	0.80	0.74	0.43	0.32
IA	0.52	0.47	0.34	0.07	0.02	0.52	0.65	0.38	0.07	0.02
ID	1.39	1.81	1.44	1.34	0.87	1.35	1.71	1.27	1.06	0.79
IL	0.49	0.56	0.36	0.14	0.00	0.52	0.61	0.37	0.14	0.00
IN	0.67	0.66	0.52	0.16	0.11	0.69	0.70	0.55	0.17	0.11
KS	1.10	1.06	0.38	0.23	0.20	1.05	1.09	0.47	0.33	0.31
KY	0.80	0.76	0.44	0.34	0.20	0.82	0.78	0.40	0.30	0.21
LA	0.79	0.80	0.67	0.30	0.20	0.78	0.79	0.67	0.30	0.20
MA	0.46	0.46	0.34	0.28	0.18	0.47	0.45	0.33	0.29	0.18
MD	1.03	1.04	0.86	0.54	0.59	1.10	1.09	0.84	0.51	0.56
ME	1.68	1.40	0.76	0.51	0.29	1.68	1.42	0.83	0.51	0.29
MI	0.79	0.84	0.68	0.46	0.27	0.79	0.85	0.69	0.46	0.26
MN	0.53	0.48	0.21	0.08	0.03	0.62	0.66	0.21	0.08	0.03
MO	0.26	0.38	0.19	0.02	0.01	0.27	0.44	0.21	0.02	0.01
MS	0.89	0.83	0.59	0.33	0.17	0.88	0.83	0.60	0.33	0.17
MT	0.17	0.17	0.76	0.03	0.00	0.17	0.18	0.35	0.03	0.00
NC	0.90	0.72	0.77	0.67	0.64	0.89	0.74	0.74	0.65	0.64
ND	0.46	0.86	0.75	0.43	0.06	0.56	1.04	0.61	0.43	0.06
NE	2.37	2.23	2.72	2.45	1.65	2.37	2.83	2.69	2.31	1.48

	Alternative 2					Final Rules				
State Tag	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
NH	0.57	0.42	0.36	0.27	0.25	0.56	0.42	0.36	0.27	0.25
NJ	0.82	0.84	0.67	0.41	0.41	0.83	0.86	0.68	0.42	0.41
NM	0.52	0.52	0.83	0.86	0.98	0.52	0.52	0.83	0.79	1.00
NV	0.71	0.79	0.87	0.84	0.37	0.69	0.84	0.87	0.85	0.38
NY	0.87	0.84	0.61	0.26	0.27	0.87	0.86	0.61	0.27	0.27
OH	0.94	0.94	0.85	0.59	0.41	0.94	0.93	0.83	0.57	0.40
OK	0.95	0.81	0.30	0.07	0.07	0.93	0.90	0.31	0.07	0.07
OR	3.24	0.73	0.38	0.00	0.00	3.28	0.73	0.38	0.00	0.00
PA	0.85	0.81	0.63	0.38	0.33	0.85	0.81	0.65	0.42	0.33
RI	0.83	0.79	0.61	0.38	0.33	0.83	0.79	0.61	0.38	0.34
SC	0.81	0.89	0.67	0.52	0.54	0.81	0.90	0.67	0.50	0.55
SD	0.70	0.65	0.41	0.25	0.02	0.61	0.89	0.44	0.26	0.02
TN	1.09	1.05	0.87	0.47	0.26	1.11	1.05	0.87	0.48	0.26
TX	0.81	0.75	0.49	0.19	0.10	0.80	0.77	0.50	0.20	0.10
UT	0.66	0.83	0.79	0.84	0.65	0.67	0.83	0.78	0.84	0.65
VA	0.82	0.72	0.60	0.28	0.18	0.82	0.73	0.61	0.30	0.19
VT	0.00	0.00	0.03	0.03	0.00	0.00	0.00	0.03	0.03	0.00
WA	0.44	0.49	0.56	0.61	0.39	0.45	0.48	0.56	0.61	0.39
WI	0.55	0.63	0.52	0.19	0.11	0.57	0.79	0.52	0.19	0.11
WV	0.50	0.38	0.32	0.10	0.12	0.50	0.41	0.40	0.11	0.12
WY	0.01	0.01	1.30	0.41	0.00	0.03	0.02	1.32	0.53	0.00

Table B-18 Baseline and Alternative 1 Scaling Factors for Other EGU Tags

	Baseline					Alternative 1				
Pollutants	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
Seasonal NO_X	1.16	1.16	1.10	1.04	1.03	1.16	1.17	1.11	1.04	1.03
Annual NO_X	1.17	1.17	1.11	1.03	1.00	1.17	1.17	1.12	1.03	1.00
Annual SO_2	1.00	1.01	1.00	0.90	0.87	0.99	1.01	1.00	0.90	0.87
Annual $PM_{2.5}$	1.37	1.37	1.32	1.27	1.20	1.38	1.39	1.34	1.28	1.20

Table B-19 Alternative 2 and Final Rules Scaling Factors for Other EGU Tags

	Alternative 2					Final Rules				
Pollutants	2028	2030	2035	2040	2045	2028	2030	2035	2040	2045
Seasonal NO_X	1.16	1.17	1.11	1.04	1.03	1.16	1.17	1.12	1.05	1.03
Annual NO_X	1.17	1.17	1.12	1.03	1.00	1.17	1.18	1.12	1.04	1
Annual SO_2	0.99	1.01	1.00	0.90	0.87	0.99	1.01	1	0.9	0.87
Annual $PM_{2.5}$	1.38	1.39	1.34	1.28	1.20	1.41	1.41	1.37	1.3	1.22

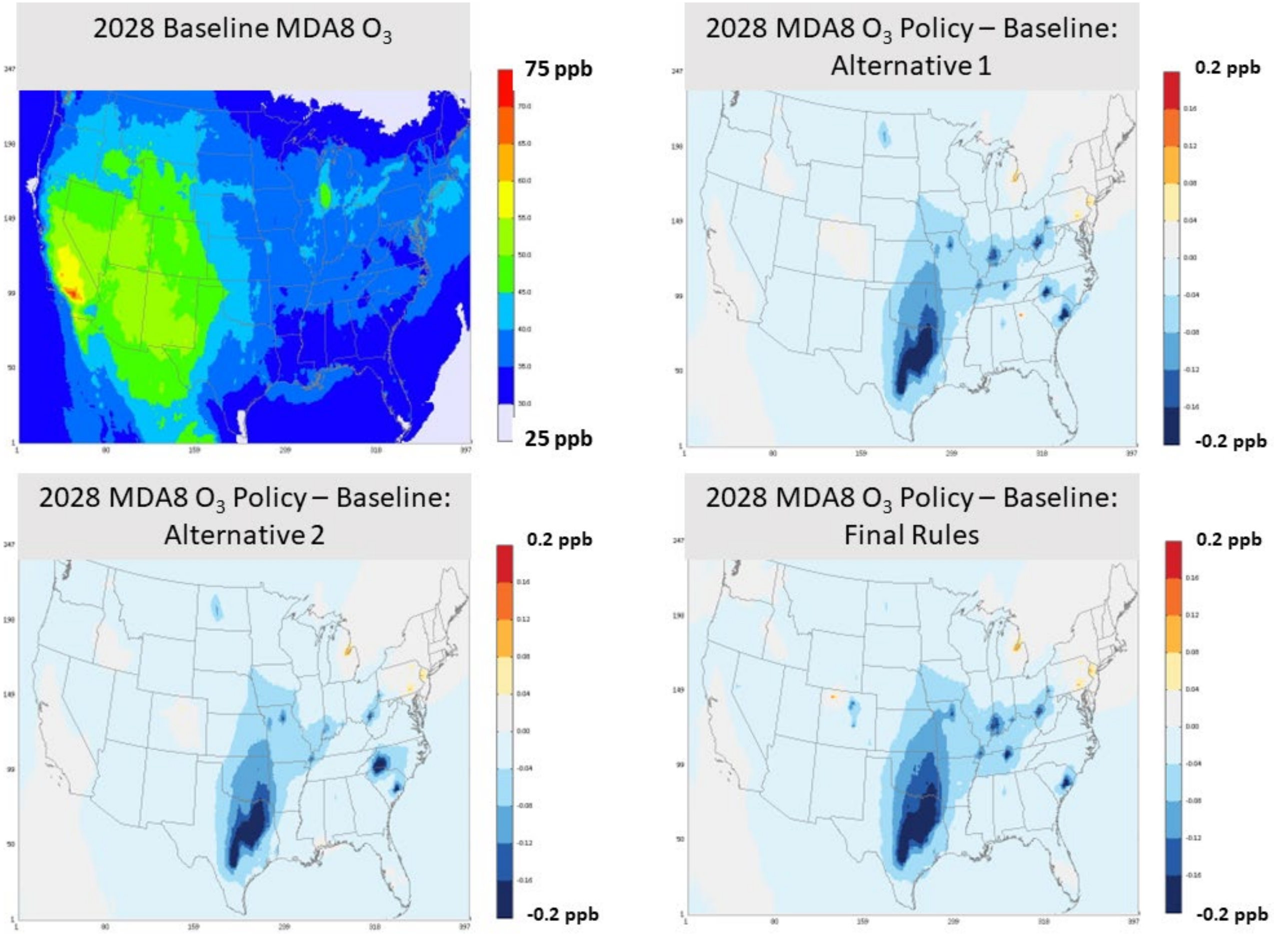
B.4 Air Quality Surface Results

The spatial fields of baseline AS-MO3 and Annual Average $PM_{2.5}$ in 2028, 2030, 2035, 2040 and 2045 are presented in Figure B-8 through Figure B-12. 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 MDA8 ozone concentrations on specific high ozone episode days. $PM_{2.5}$ is made up of both primary and secondary components. Secondary $PM_{2.5}$ species sulfate and nitrate often demonstrate regional signals without large local gradients while primary $PM_{2.5}$ components often have heterogenous spatial patterns with larger gradients near emissions sources. Both secondary and primary $PM_{2.5}$ contribute to the spatial patterns shown in Figure B-13 through Figure B-17 as demonstrated by the extensive areas of elevated concentrations over much of the Eastern U.S. which have large secondary components and hotspots in urban areas which are impacted by primary PM emissions.

Figure B-8 through Figure B-17 also present the model-predicted air quality changes between the baseline and the three illustrative scenarios in 2028, 2030, 2035, 2040 and 2045 for AS-MO3 and $PM_{2.5}$. Difference in these figures are calculated as the illustrative scenario minus the baseline. The spatial patterns shown in the figures are a result of (1) of the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) of the physical or chemical processing that the model simulates in the atmosphere. While SO_2, NO_X, and primary $PM_{2.5}$ emissions changes all contributed to the $PM_{2.5}$ changes depicted in Figure B-13 through

Figure B-17, the $PM_{2.5}$ component species with the largest changes on average was sulfate and consequently the SO_2 emissions changes have the largest impact on predicted changes in $PM_{2.5}$ concentrations in most locations through sulfate, ammonium and particle-bound water impacts. The spatial fields used to create these maps serve as an input to the benefits analysis and the environmental justice analysis.

Figure B-18 though Figure B-21 show changes in AS-MO3 in 2030, 2035, 2040, and 2045 relative to 2028 baseline conditions. Figure B-22 through Figure B-25 show changes in $PM_{2.5}$ in 2030, 2035, 2040, and 2045 relative to 2028 baseline conditions. Relative to 2028 baseline conditions, these figures indicate that ozone and $PM_{2.5}$ concentration will decline in virtually all areas of the country for both baseline and final rules scenarios in each further out snapshot year. However, some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ over time as a result of the modeled changes resulting from this rule. Our comparison of air quality conditions with and without the rule suggests that for all snapshot years the final rules will result in widespread reductions in $PM_{2.5}$ concentrations. In all years, the final rules are expected to result in reductions in ozone concentrations over many areas of the US, although some areas may experience increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years.



2028 Baseline MDA8 O_3

2028 MDA8 O_3 Policy – Baseline: Alternative 1

2028 MDA8 O_3 Policy – Baseline: Alternative 2

2028 MDA8 O_3 Policy – Baseline: Final Rules

Figure B-8 Maps of ASM-O3 in 2028

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the alternative 1 scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the alternative 2 scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the final rules scenario compared to baseline values shown in lower right (ppb).

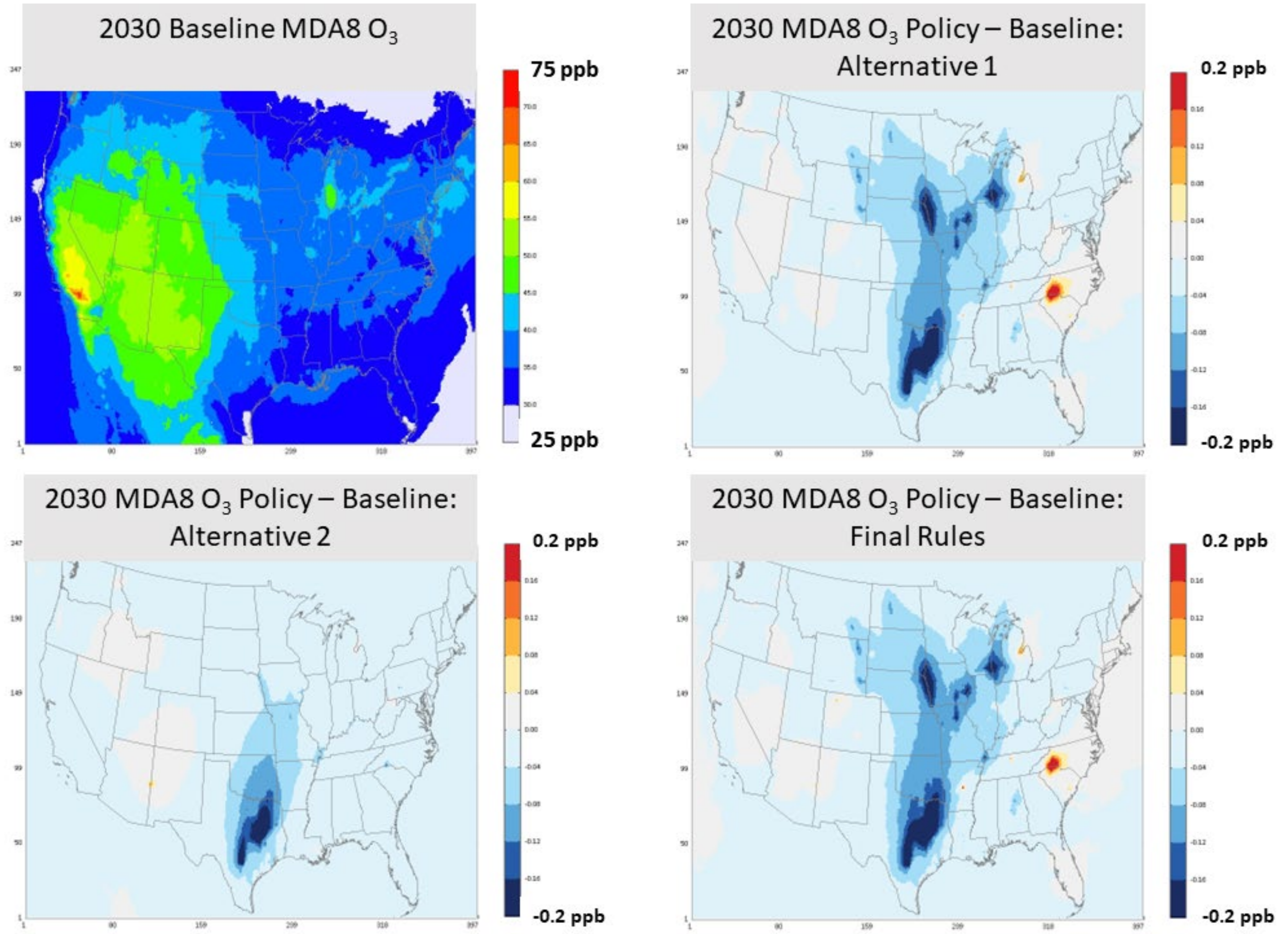


Figure B-9 Maps of ASM-O3 in 2030

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the alternative 1 scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the alternative 2 scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the final rules scenario compared to baseline values shown in lower right (ppb).

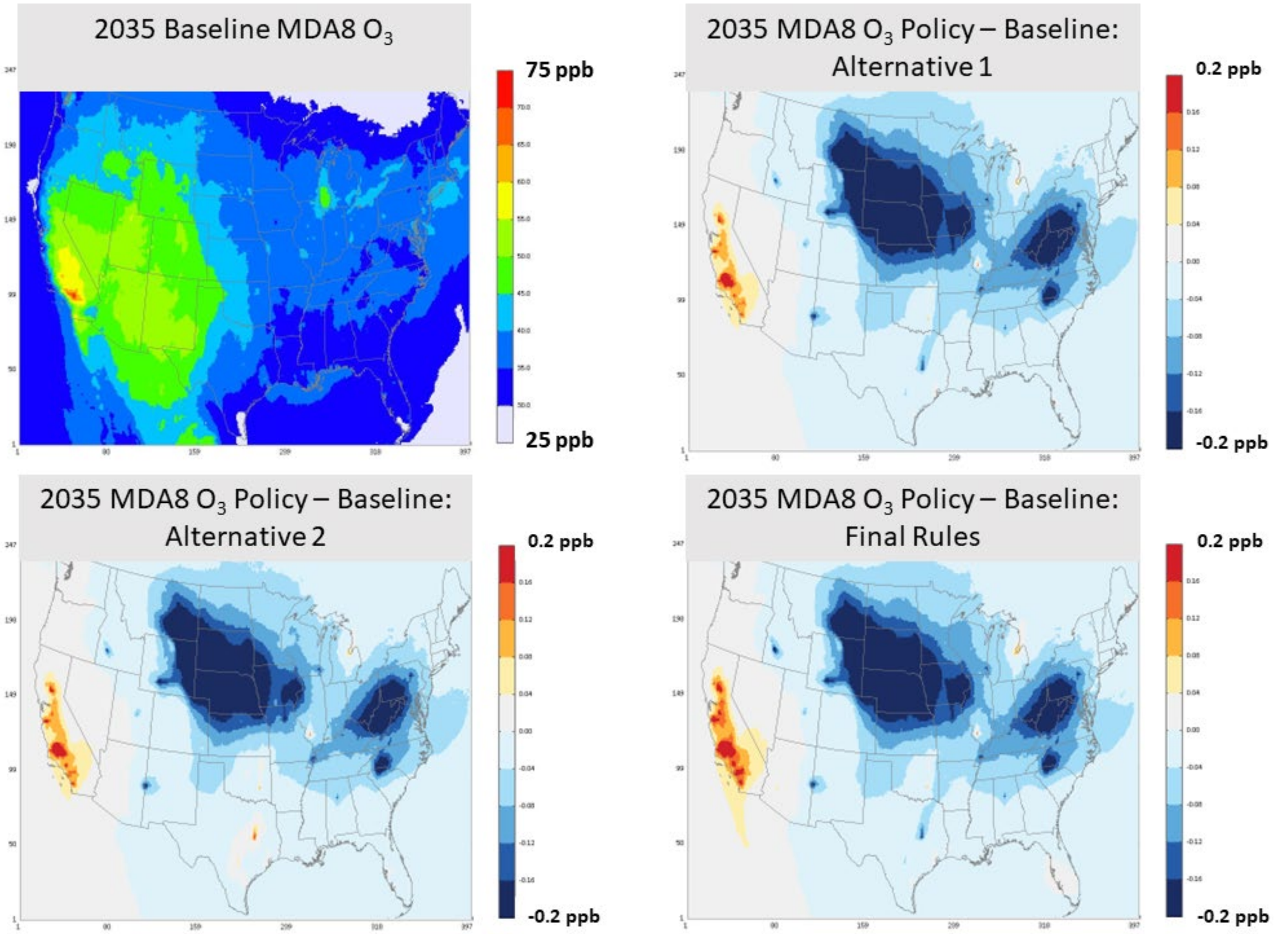


Figure B-10 Maps of ASM-O3 in 2035

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the alternative 1 scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the alternative 2 scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the final rules scenario compared to baseline values shown in lower right (ppb).

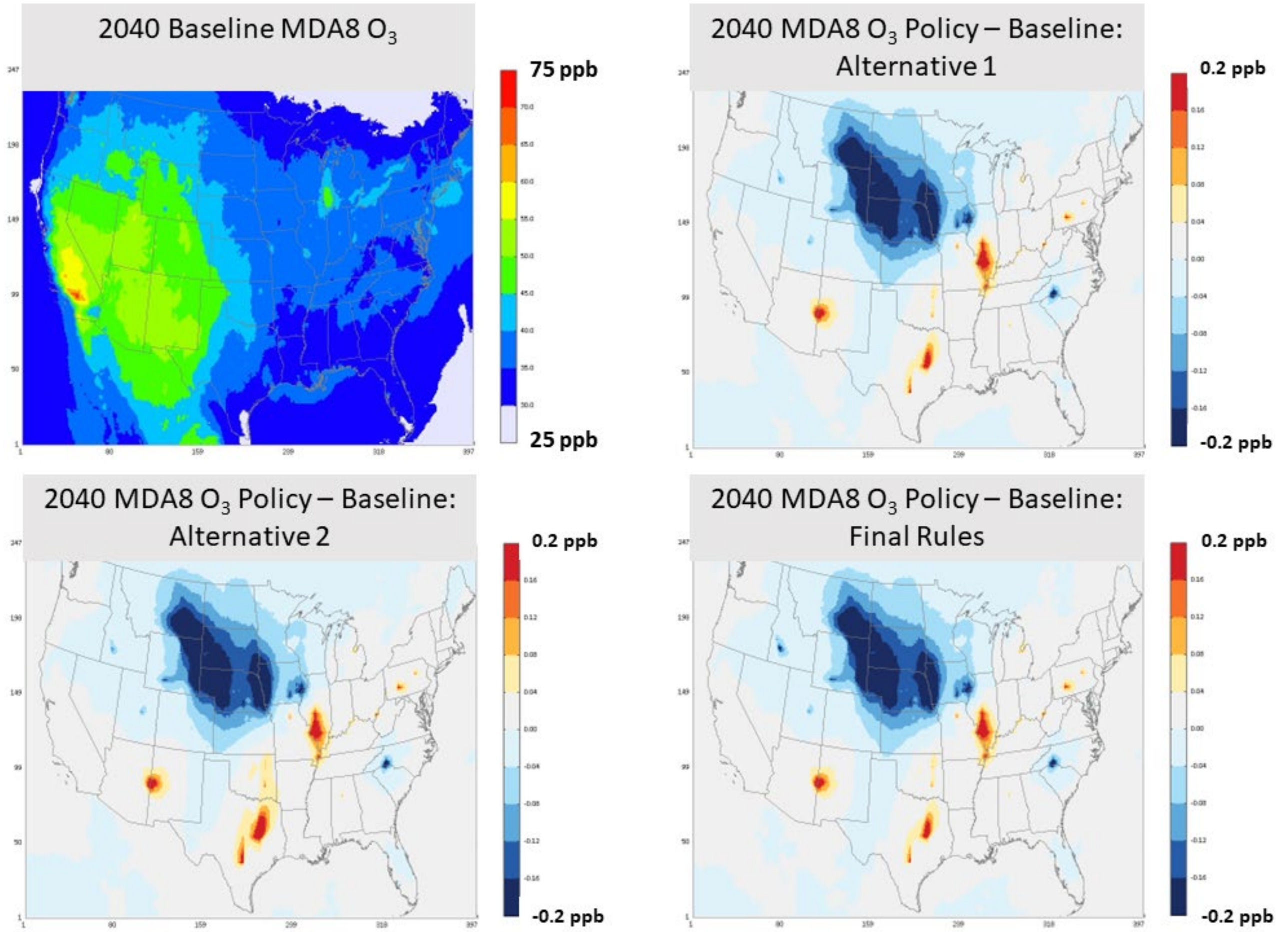
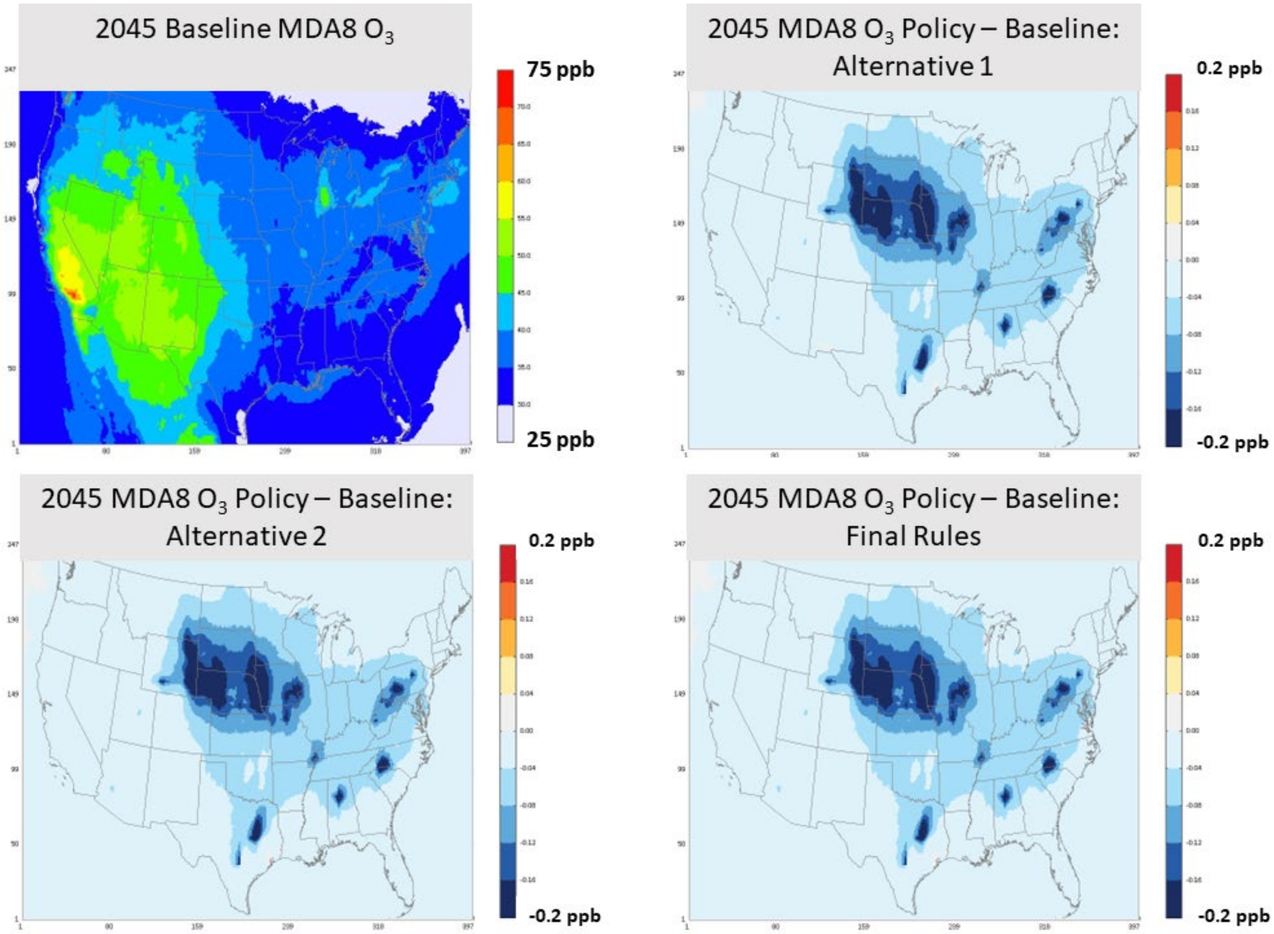


Figure B-11 Maps of ASM-O3 in 2040

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the alternative 1 scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the alternative 2 scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the final rules scenario compared to baseline values shown in lower right (ppb).


2045 Baseline MDA8 O_3

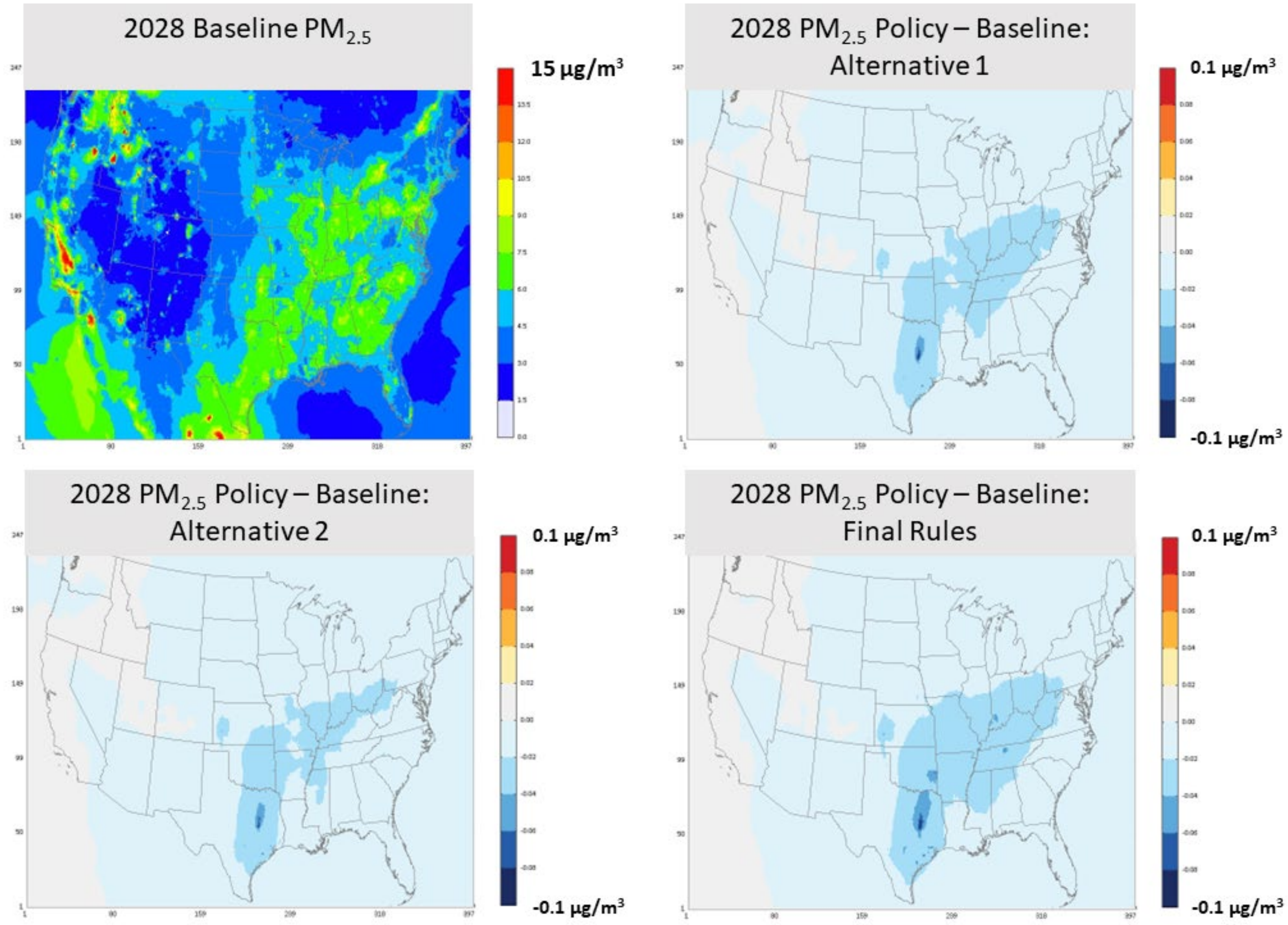
2045 MDA8 O_3 Policy – Baseline: Alternative 1

2045 MDA8 O_3 Policy – Baseline: Alternative 2

2045 MDA8 O_3 Policy – Baseline: Final Rules

Figure B-12 Maps of ASM-O3 in 2045

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the alternative 1 scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the alternative 2 scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the final rules scenario compared to baseline values shown in lower right (ppb).



2028 Baseline PM$_{2.5}$

2028 PM$_{2.5}$ Policy – Baseline: Alternative 1

2028 PM$_{2.5}$ Policy – Baseline: Alternative 2

2028 PM$_{2.5}$ Policy – Baseline: Final Rules

Figure B-13 Maps of PM$_{2.5}$ in 2028

Note: Baseline PM$_{2.5}$ concentrations (µg/m^3) shown in upper left. Change in PM$_{2.5}$ in the alternative 1 scenario compared to baseline values (µg/m^3) shown in upper right. Change in PM$_{2.5}$ in the alternative 2 scenario compared to baseline values (µg/m^3) shown in lower left. Change in PM$_{2.5}$ in the final rules scenario compared to baseline values shown in lower right (µg/m^3).

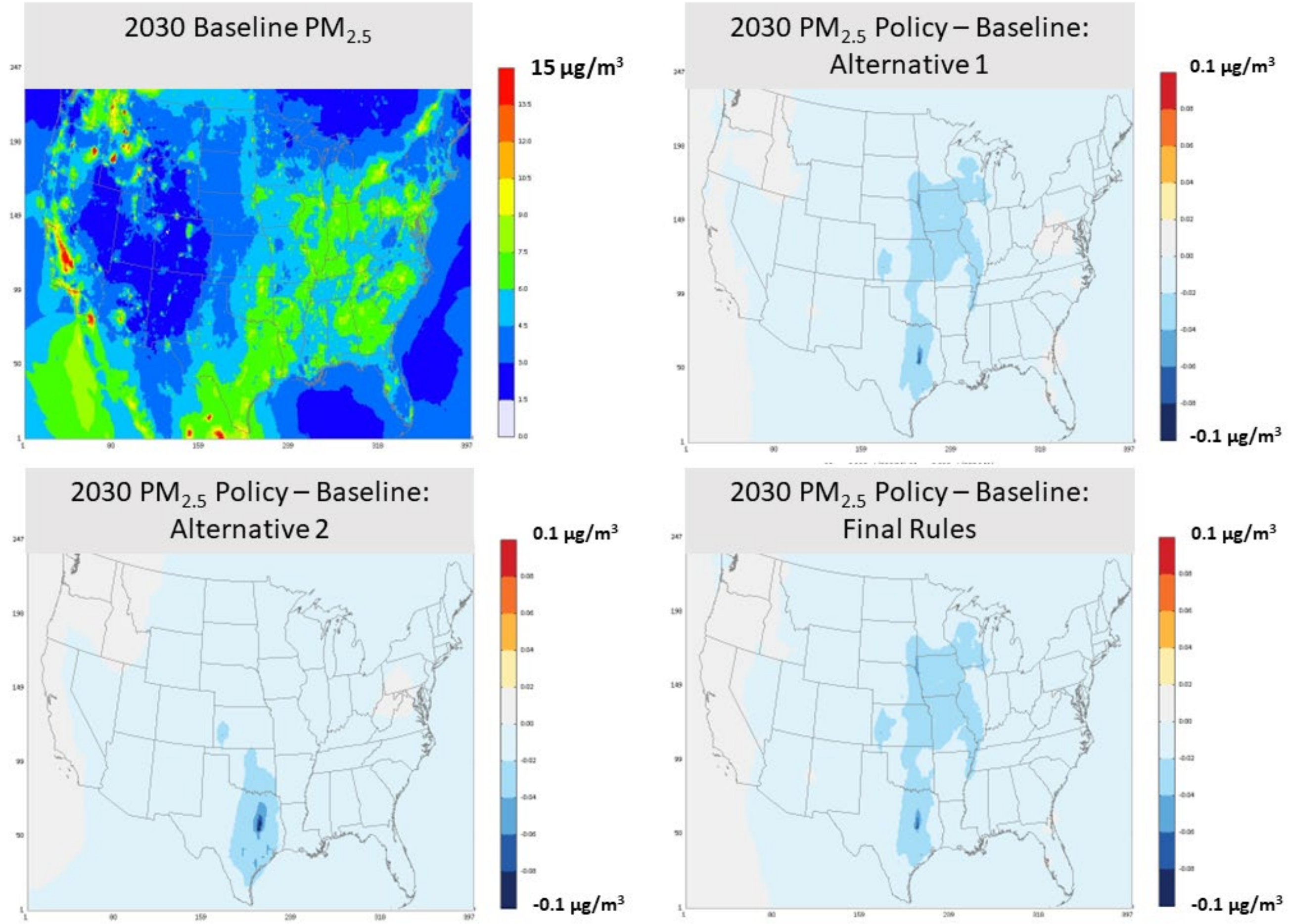


Figure B-14 Maps of $PM_{2.5}$ in 2030

Note: Baseline $PM_{2.5}$ concentrations (μg/m^3) shown in upper left. Change in $PM_{2.5}$ in the alternative 1 scenario compared to baseline values (μg/m^3) shown in upper right. Change in $PM_{2.5}$ in the alternative 2 scenario compared to baseline values (μg/m^3) shown in lower left. Change in $PM_{2.5}$ in the final rules scenario compared to baseline values shown in lower right (μg/m^3).

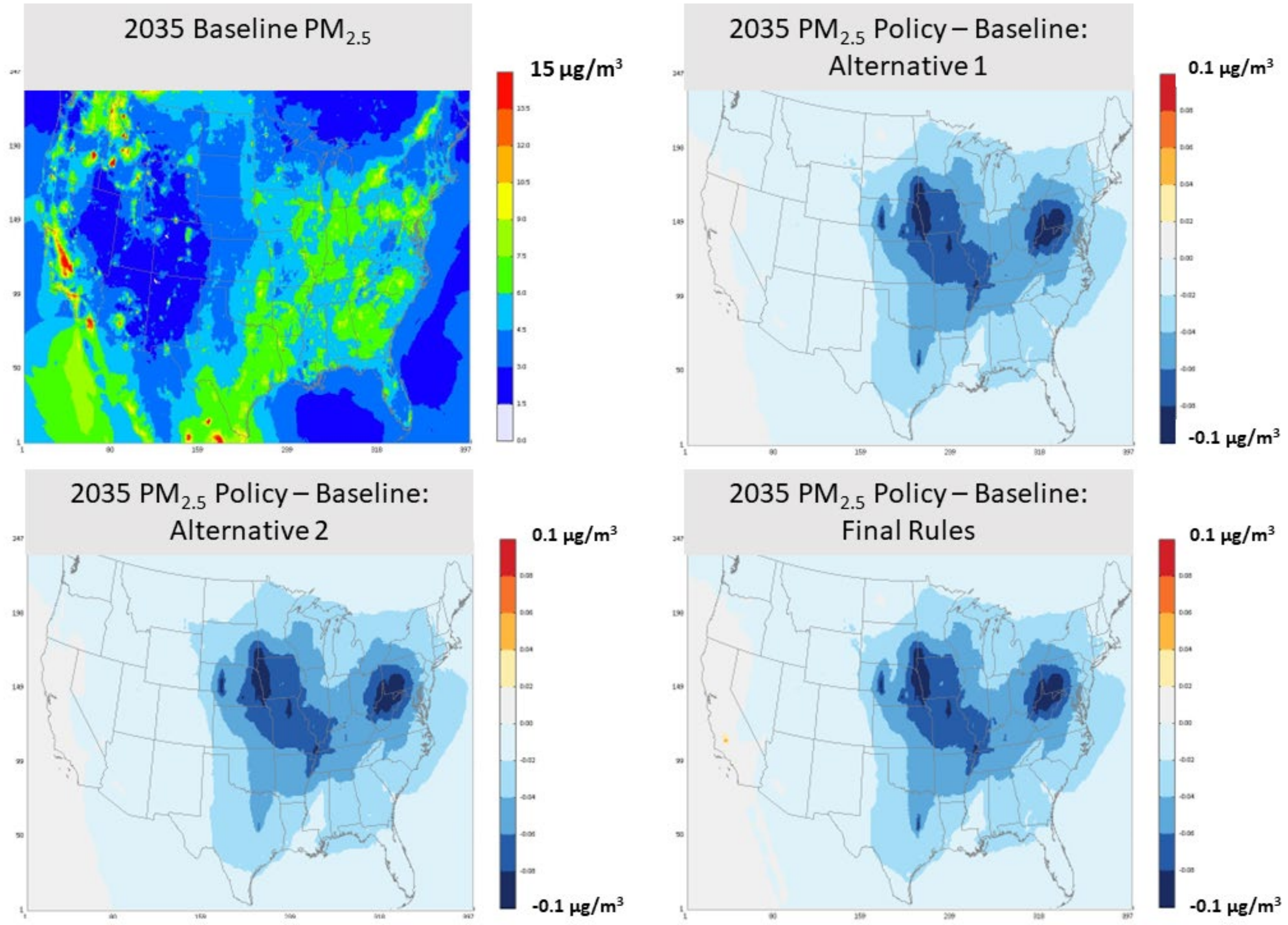


Figure B-15 Maps of $PM_{2.5}$ in 2035

Note: Baseline $PM_{2.5}$ concentrations (µg/m^3) shown in upper left. Change in $PM_{2.5}$ in the alternative 1 scenario compared to baseline values (µg/m^3) shown in upper right. Change in $PM_{2.5}$ in the alternative 2 scenario compared to baseline values (µg/m^3) shown in lower left. Change in $PM_{2.5}$ in the final rules scenario compared to baseline values shown in lower right (µg/m^3).

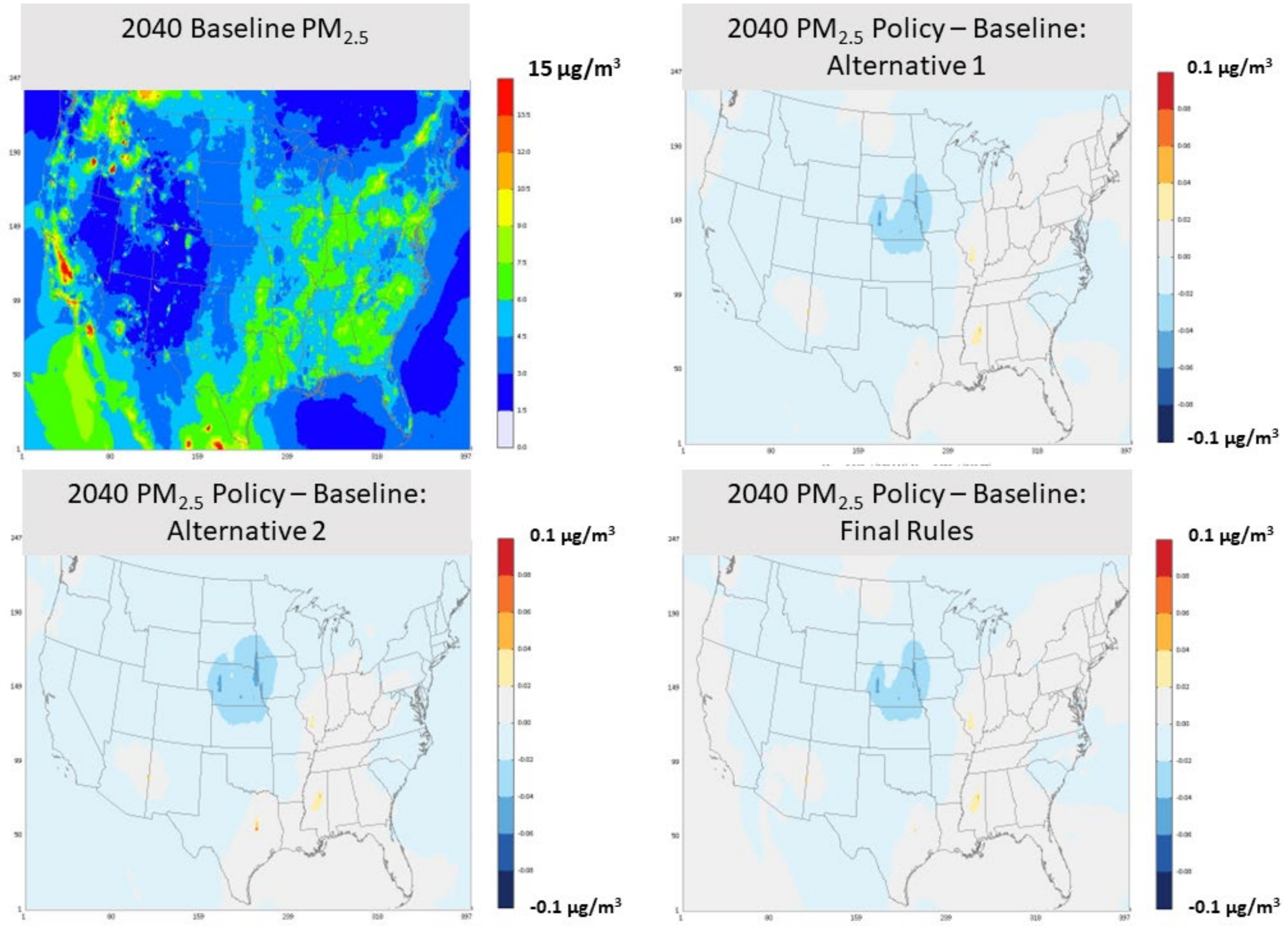


Figure B-16 Maps of $PM_{2.5}$ in 2040

Note: Baseline $PM_{2.5}$ concentrations (µg/m^3) shown in upper left. Change in $PM_{2.5}$ in the alternative 1 scenario compared to baseline values (µg/m^3) shown in upper right. Change in $PM_{2.5}$ in the alternative 2 scenario compared to baseline values (µg/m^3) shown in lower left. Change in $PM_{2.5}$ in the final rules scenario compared to baseline values shown in lower right (µg/m^3).

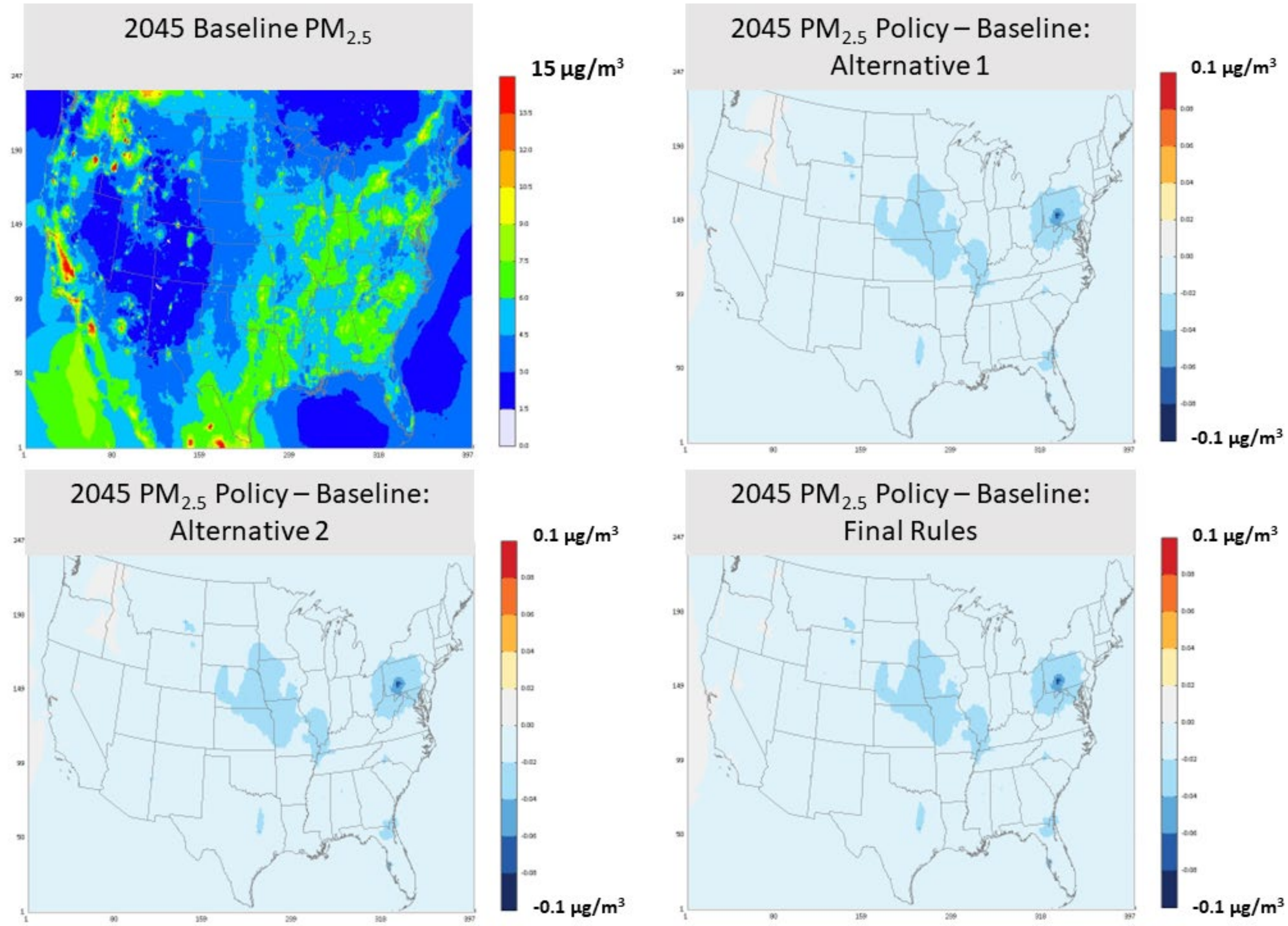


Figure B-17 Maps of $PM_{2.5}$ in 2045

Note: Baseline $PM_{2.5}$ concentrations (μg/m^3) shown in upper left. Change in $PM_{2.5}$ in the alternative 1 scenario compared to baseline values (μg/m^3) shown in upper right. Change in $PM_{2.5}$ in the alternative 2 scenario compared to baseline values (μg/m^3) shown in lower left. Change in $PM_{2.5}$ in the final rules scenario compared to baseline values shown in lower right (μg/m^3).

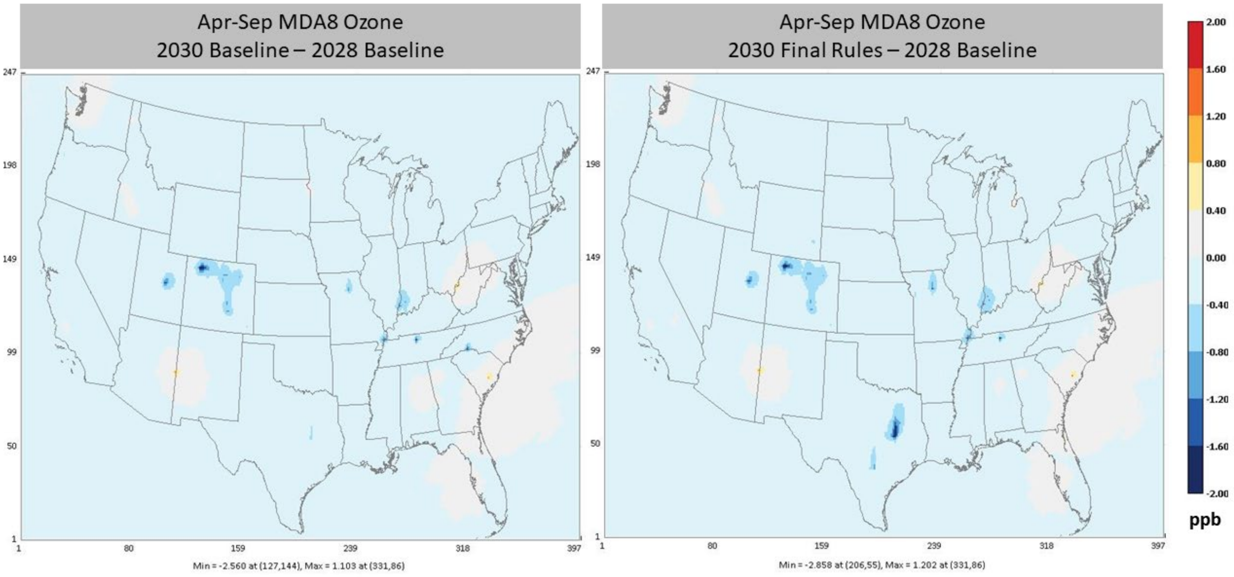


Figure B-18 Maps of changes in 2030 ASM-O3 from 2028 baseline conditions

Note: Baseline 2030 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on left. Final Rules 2030 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on right. Color bars for Figure B-18 through Figure B-21 differ in scale (±2ppb) from color bars used in Figure B-8 through Figure B-12 (±0.2ppb).

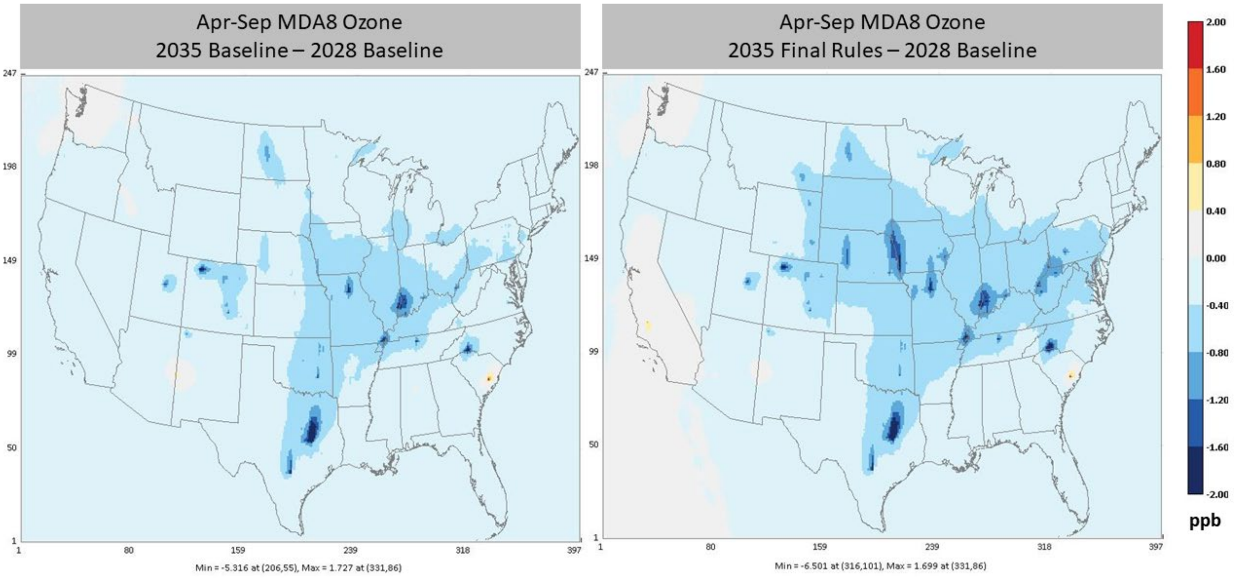


Figure B-19 Maps of changes in 2035 ASM-O3 from 2028 baseline conditions

Note: Baseline 2035 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on left. Final Rules 2035 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on right. Color bars for Figure B-18 through Figure B-21 differ in scale (±2ppb) from color bars used in Figure B-8 through Figure B-12 (±0.2ppb).

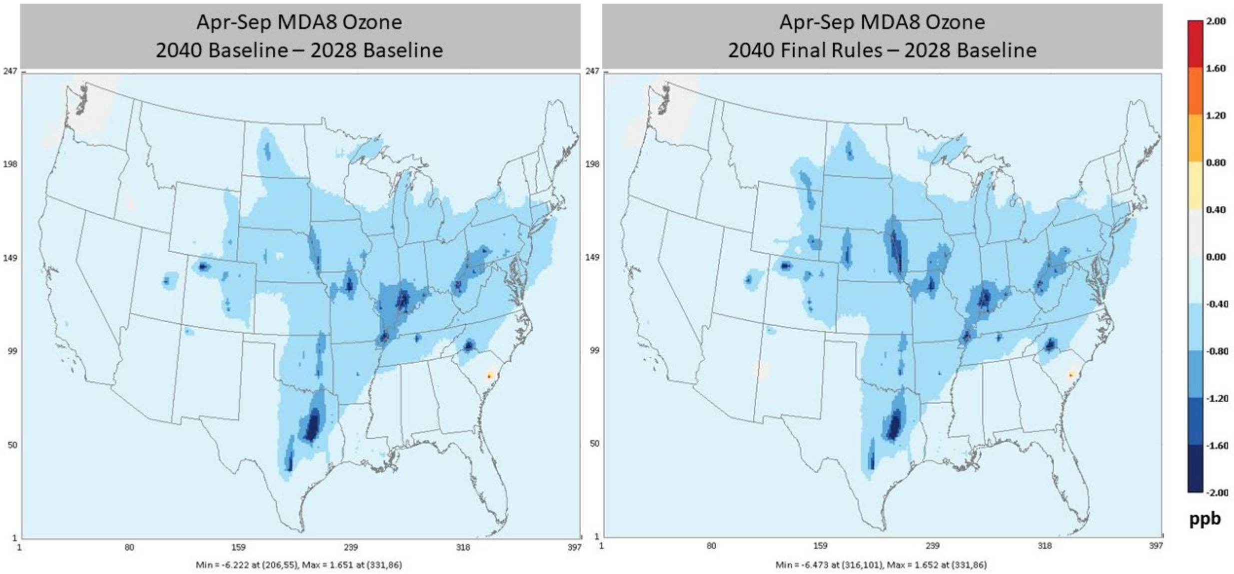


Figure B-20 Maps of changes in 2040 ASM-O3 from 2028 baseline conditions
Note: Baseline 2040 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on left. Final Rules 2040 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on right. Color bars for Figure B-18 through Figure B-21 differ in scale (±2ppb) from color bars used in Figure B-8 through Figure B-12 (±0.2ppb).

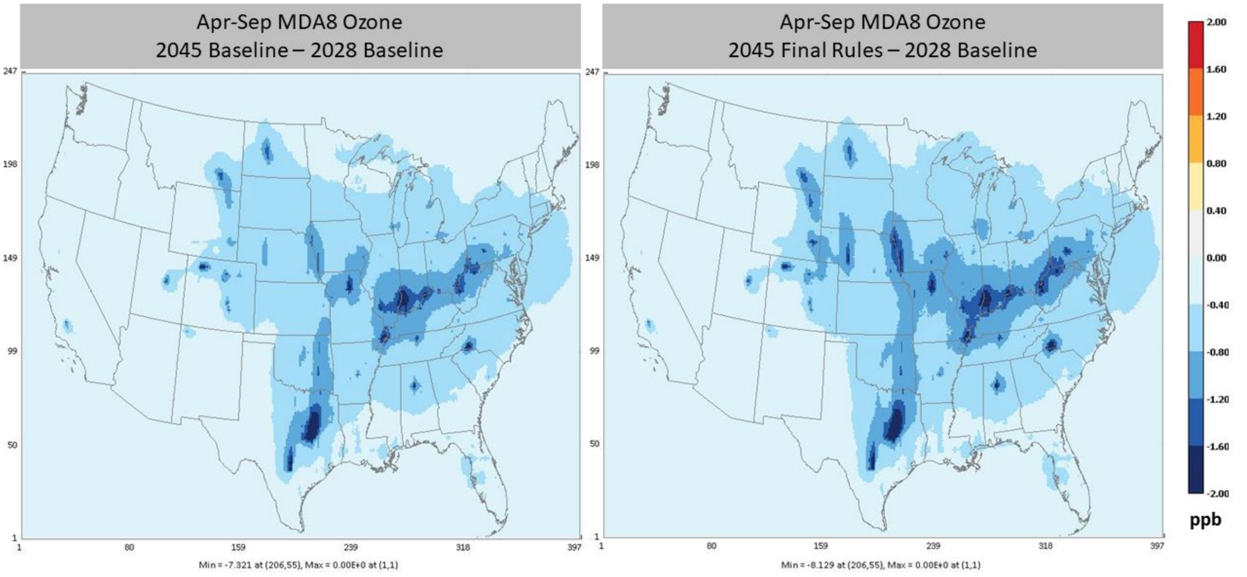


Figure B-21 Maps of changes in 2045 ASM-O3 from 2028 baseline conditions

Note: Baseline 2045 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on left. Final Rules 2045 ozone concentrations compared to 2028 baseline ozone concentrations (ppb) shown on right. Color bars for Figure B-18 through Figure B-21 differ in scale (±2ppb) from color bars used in Figure B-8 through Figure B-12 (±0.2ppb).

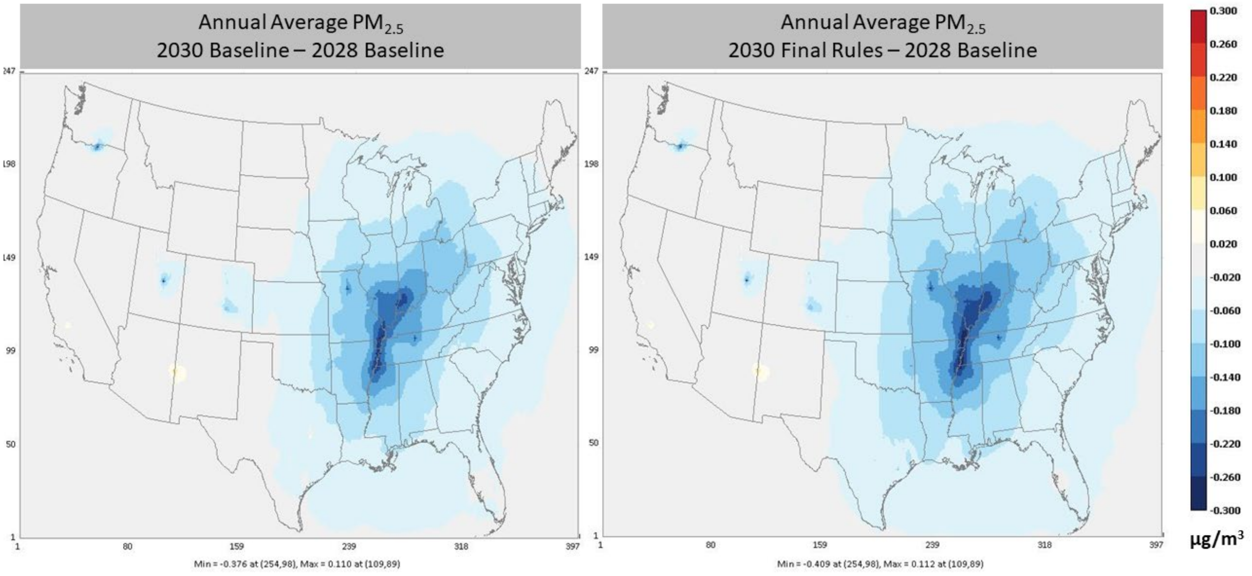


Figure B-22 Maps of changes in 2030 $PM_{2.5}$ from 2028 baseline conditions

Note: Baseline 2030 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on left. Final Rules 2030 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on right. Color bars for Figure B-22 through Figure B-25 (±0.3 µg/m^3) differ from color bars used in Figure B-13 through Figure B-17 (±0.1 µg/m^3)

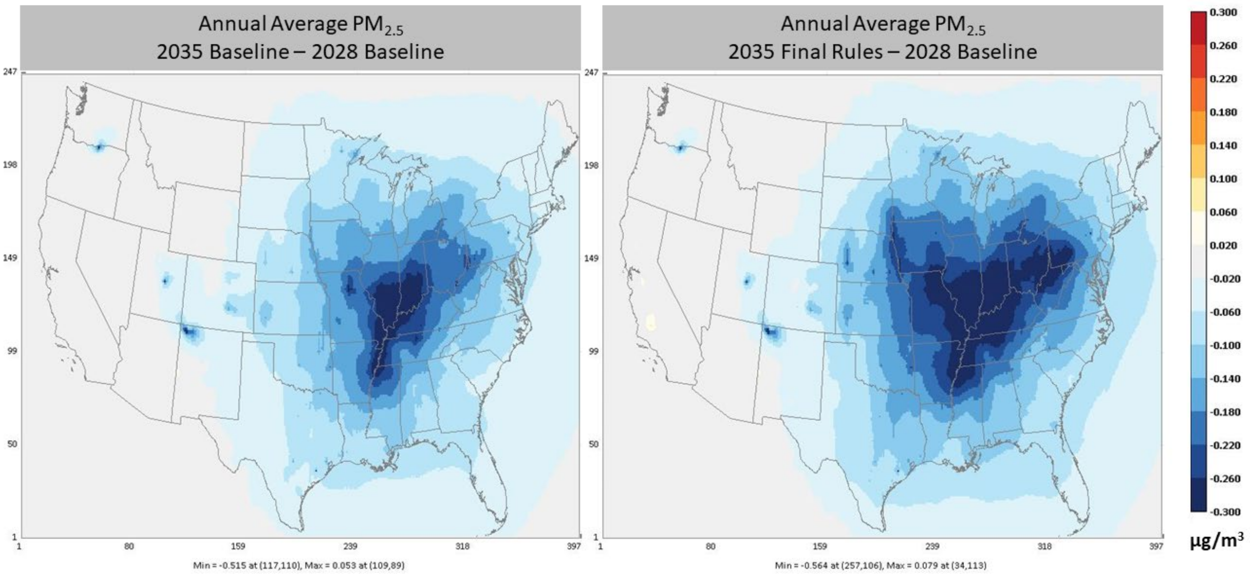


Figure B-23 Maps of changes in 2035 $PM_{2.5}$ from 2028 baseline conditions

Note: Baseline 2035 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on left. Final Rules 2035 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on right. Color bars for Figure B-22 through Figure B-25 (±0.3 µg/m^3) differ from color bars used in Figure B-13 through Figure B-17 (±0.1 µg/m^3)

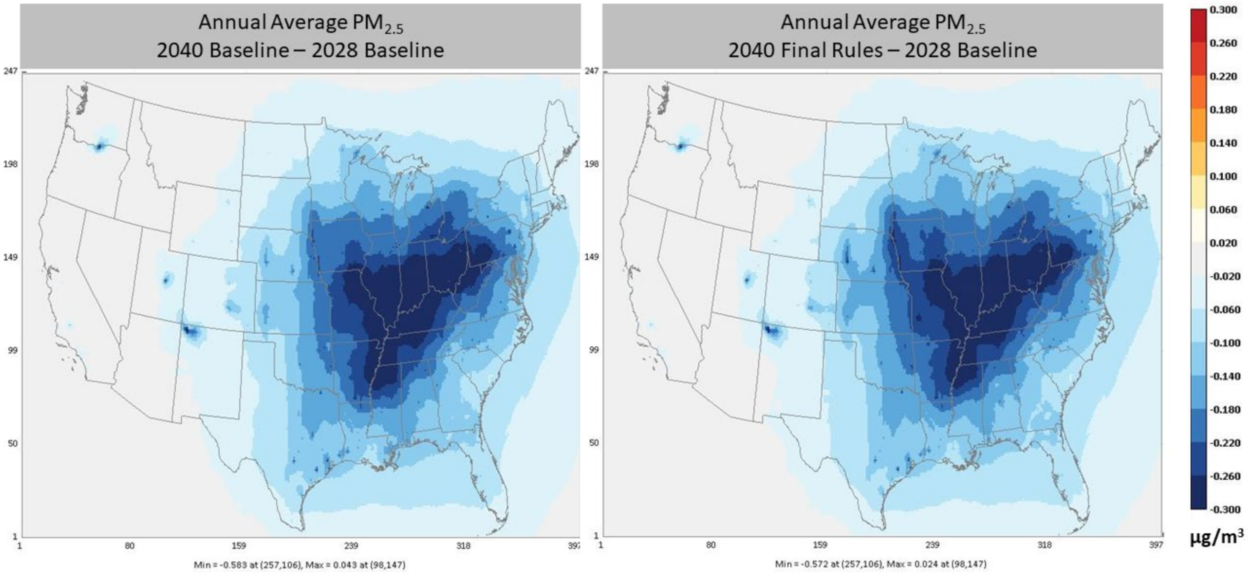


Figure B-24 Maps of changes in 2040 PM2.5 from 2028 baseline conditions

Note: Baseline 2040 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on left. Final Rules 2040 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations (µg/m^3) shown on right. Color bars for Figure B-22 through Figure B-25 (±0.3 µg/m^3) differ from color bars used in Figure B-13 through Figure B-17 (±0.1 µg/m^3)

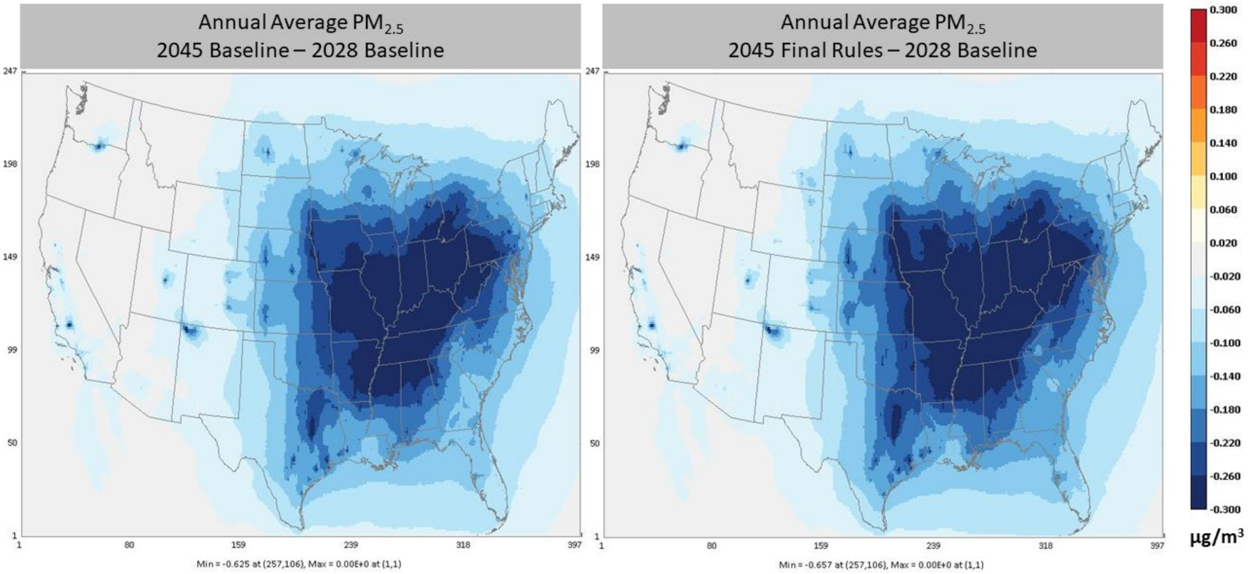


Figure B-25 Maps of changes in 2045 PM2.5 from 2028 baseline conditions

Note: Baseline 2045 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations ($\mu g/m^3$) shown on left. Final Rules 2045 $PM_{2.5}$ concentrations compared to 2028 baseline $PM_{2.5}$ concentrations ($\mu g/m^3$) shown on right. Color bars for Figure B-22 through Figure B-25 ($\pm 0.3\ \mu g/m^3$) differ from color bars used in Figure B-13 through Figure B-17 ($\pm 0.1\ \mu g/m^3$)

B.5 Uncertainties and Limitations of the Air Quality Methodology

One limitation of the scaling methodology for creating ozone and $PM_{2.5}$ surfaces associated with the baseline or illustrative scenarios described above is that the methodology 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. The method applied in this analysis is consistent with how air quality estimations have been made in several prior regulatory analyses (U.S. EPA, 2012, 2019, 2020a). We note that air quality is calculated in the same manner for the baseline and for the illustrative scenarios, so any uncertainties associated with these assumptions is propagated through results for both the baseline and the illustrative scenarios in the same manner. In addition, emissions changes between baseline and illustrative scenarios are relatively small compared to modeled future year emissions that form the basis of the source apportionment approach described in this appendix. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Cohan et al., 2005; Cohan and Napelenok, 2011; Dunker et al., 2002; Koo et al., 2007; Napelenok et al., 2006; Zavala et al., 2009). A second limitation is that the source apportionment contributions are informed by the spatial and temporal distribution of the emissions from each source tag as they occur in the future year modeled case. Thus, the contribution modeling results do not allow us to consider the effects of any changes to spatial distribution of EGU emissions within a state-fuel tag between the future year modeled case and the baseline and illustrative scenarios analyzed in this RIA. Finally, the future year 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 concentrations (U.S. EPA, 2023a, 2024).

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APPENDIX C: ENVIRONMENTAL JUSTICE ANALYSIS

C.1 Exposure Analysis Figures for the Alternative Scenarios

This appendix provides additional figures to complement the analysis in Section 6.

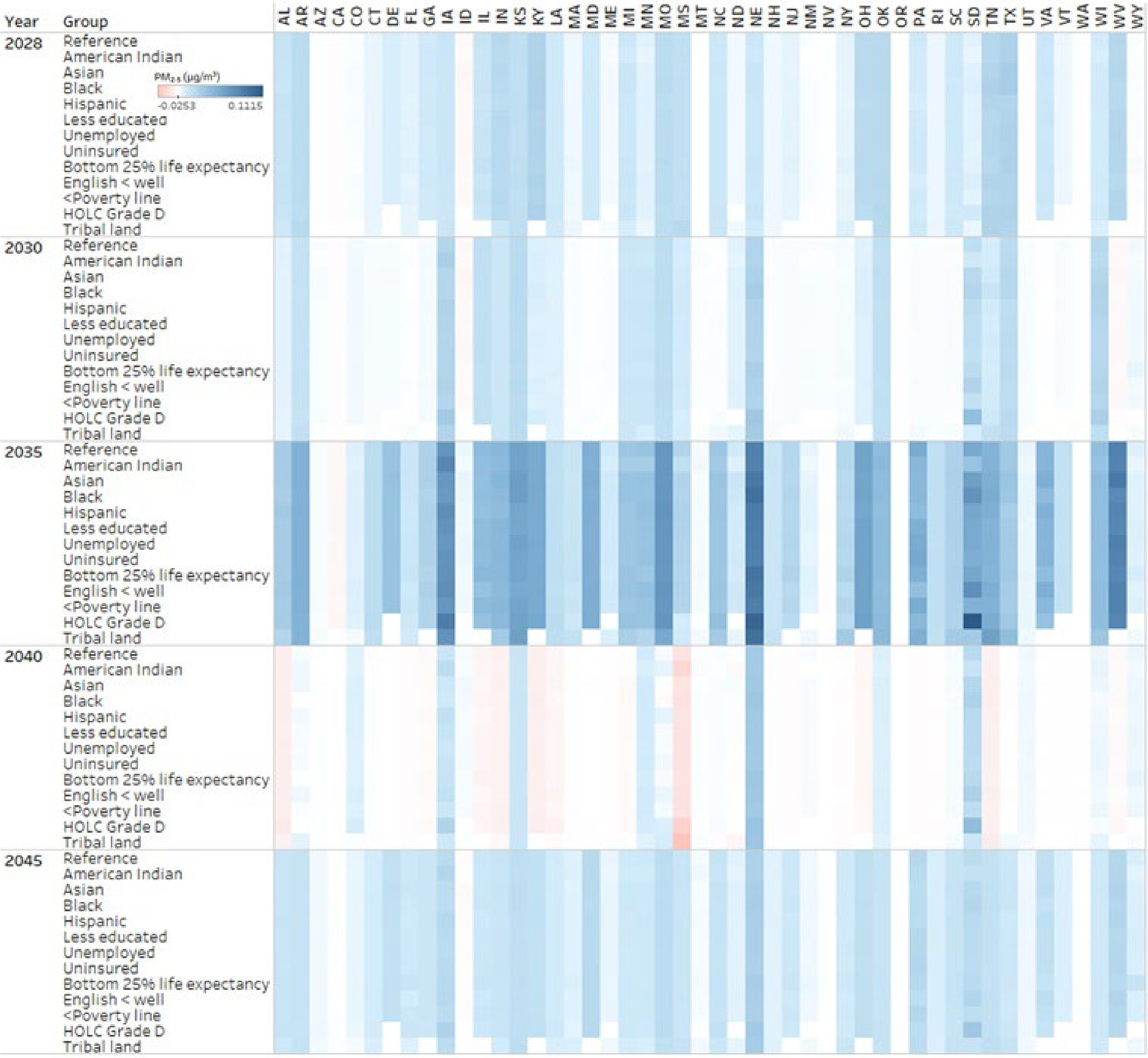

Figure C-1 Heat Map of the State Average $PM_{2.5}$ Concentration Reductions (Blue) and Increases (Red) Due to the Alternative 1 Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (µg/m^3)

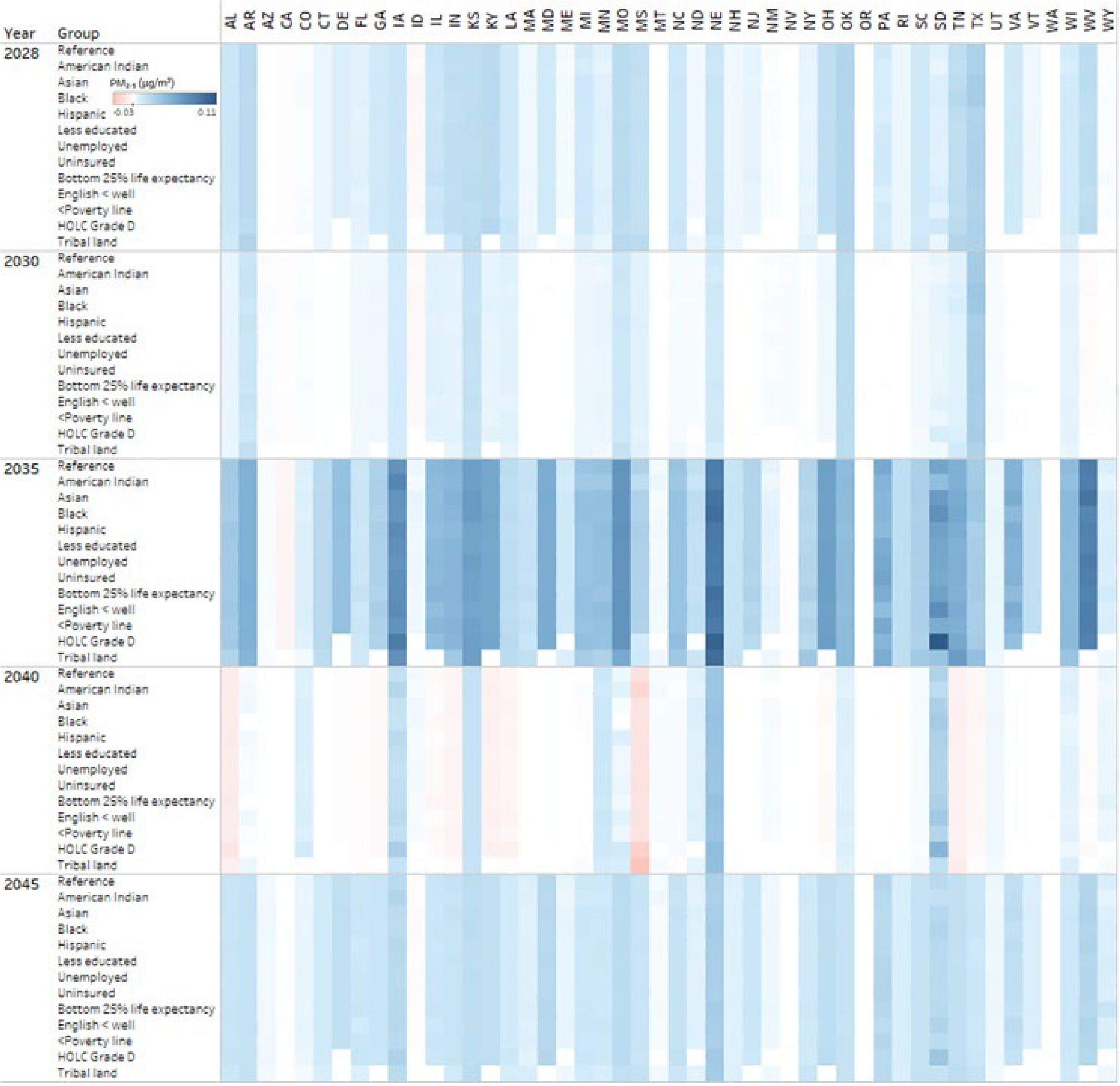

Figure C-2 Heat Map of the State Average $PM_{2.5}$ Concentration Reductions (Blue) and Increases (Red) Due to the Alternative 2 Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (μg/m^3)

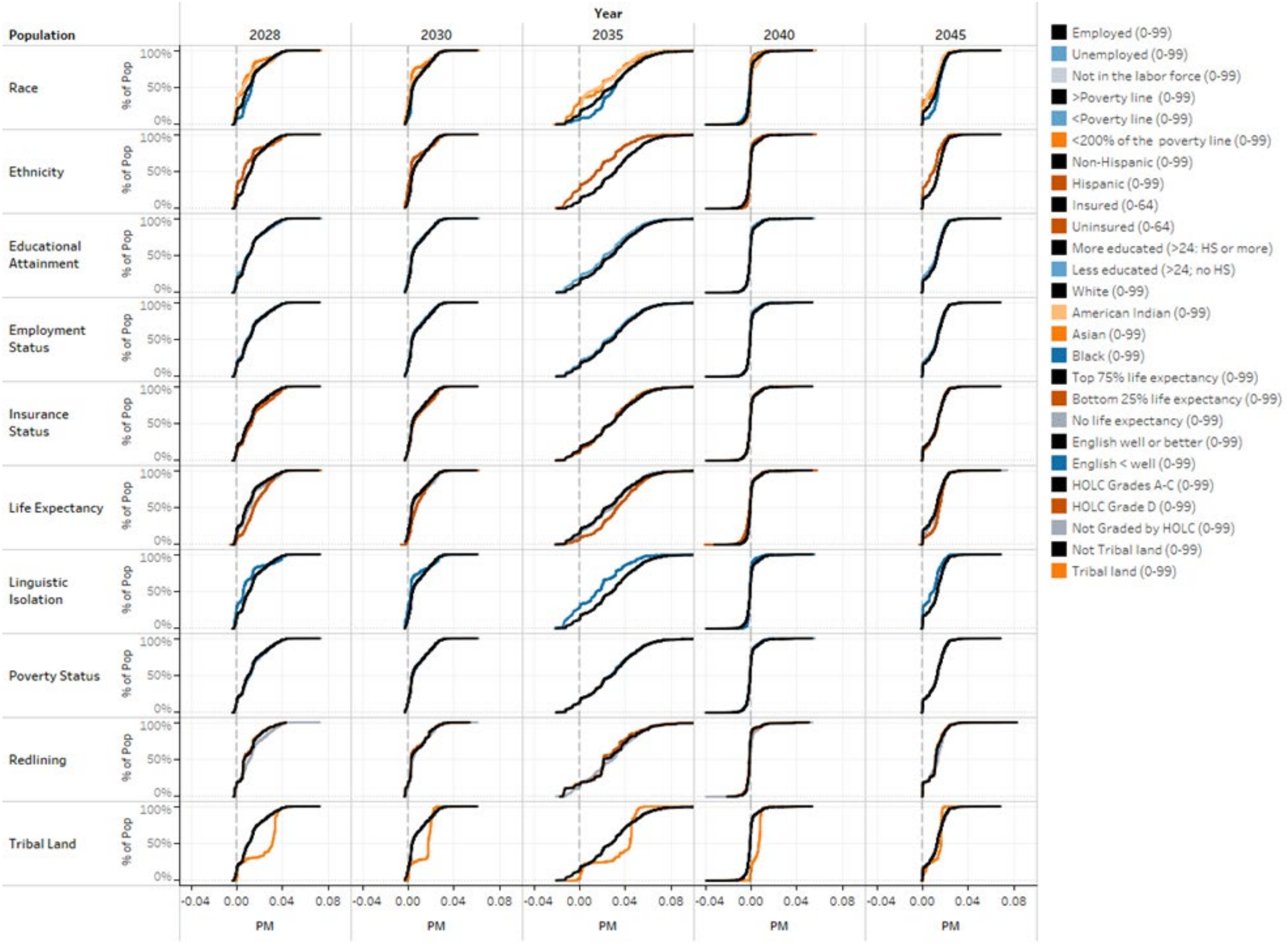

Figure C-3 Distribution of $PM_{2.5}$ Concentration (µg/m^3) Reductions Across Populations, Future Years for the Alternative 1 Scenario

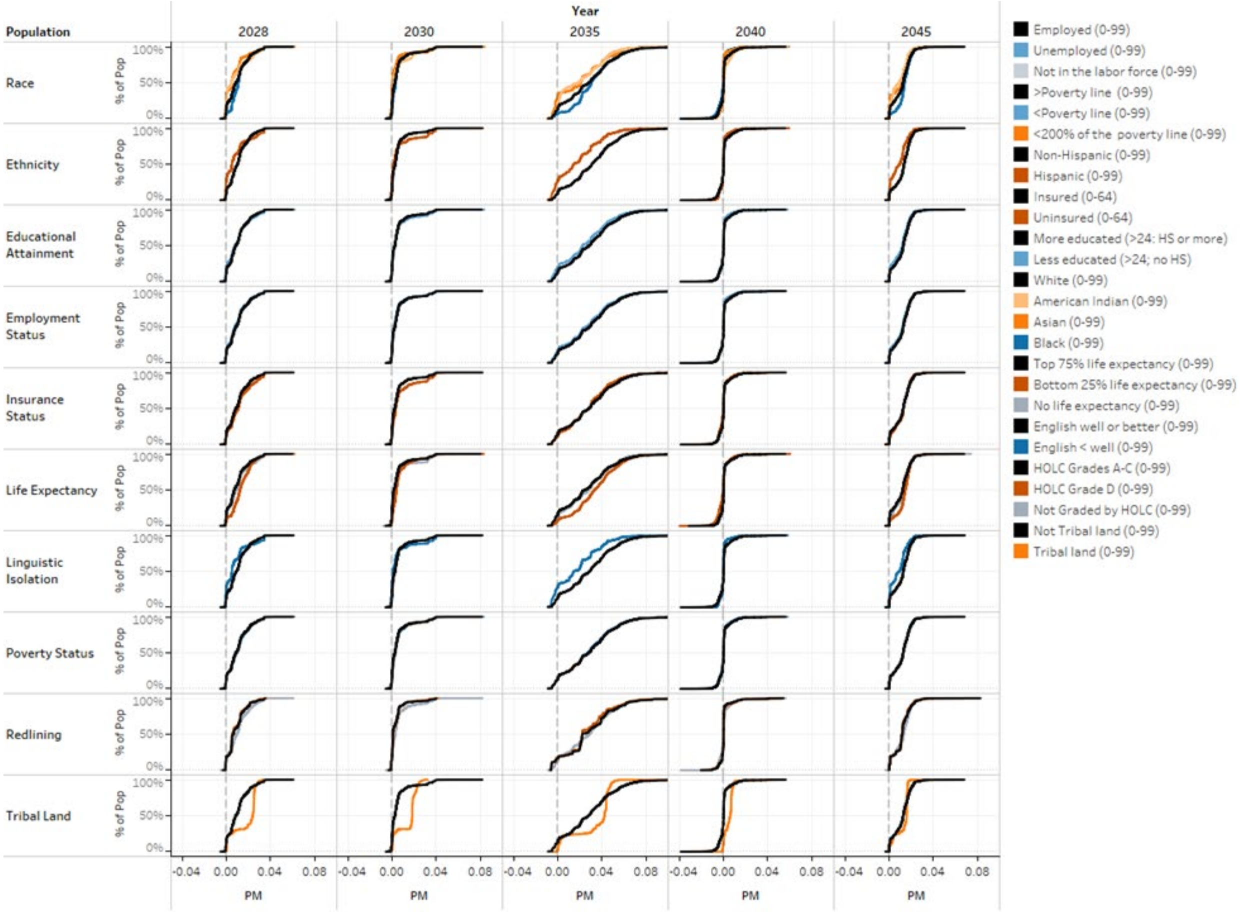

Figure C-4 Distribution of PM$_{2.5}$ Concentration (µg/m^3) Reductions Across Populations, Future Years for the Alternative 2 Scenario

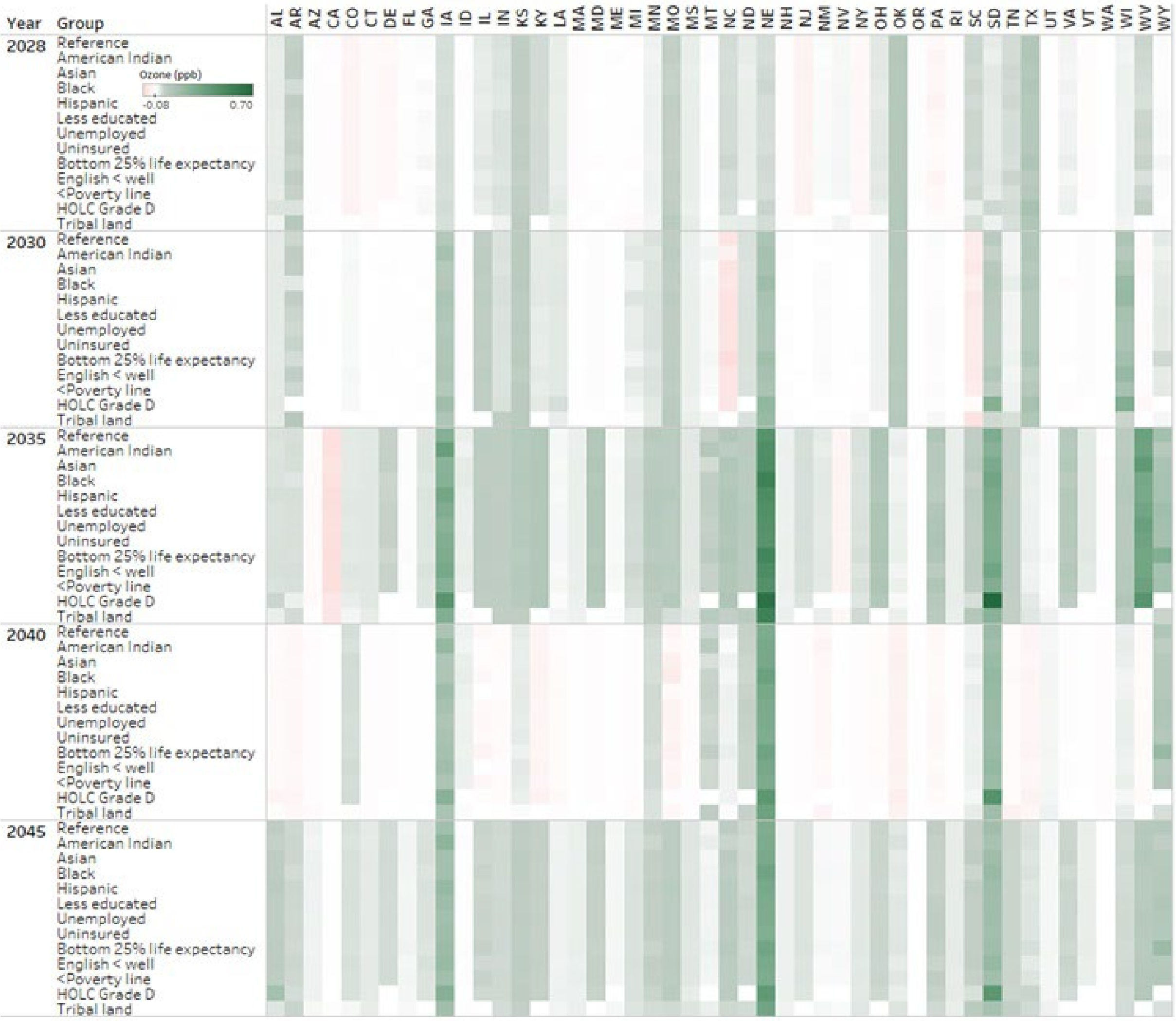

Figure C-5 Heat Map of the State Average Ozone Concentrations Reductions (Green) and Increases (Red) Due to the Alternative 1 Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (ppb)

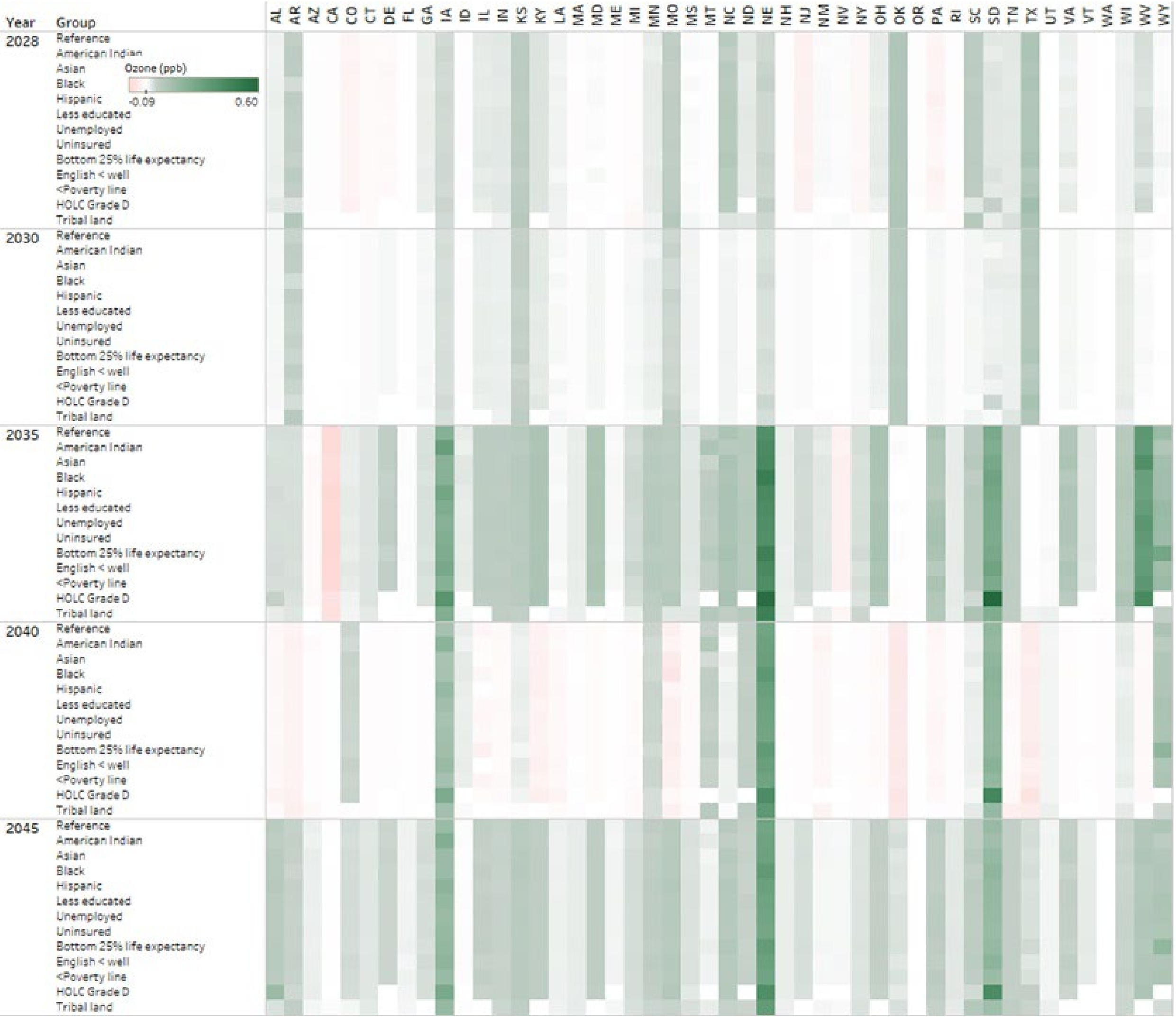

Figure C-6 Heat Map of the State Average Ozone Concentrations Reductions (Green) and Increases (Red) Due to the Alternative 2 Scenario Across Demographic Groups in 2028, 2030, 2035, 2040, and 2045 (ppb)

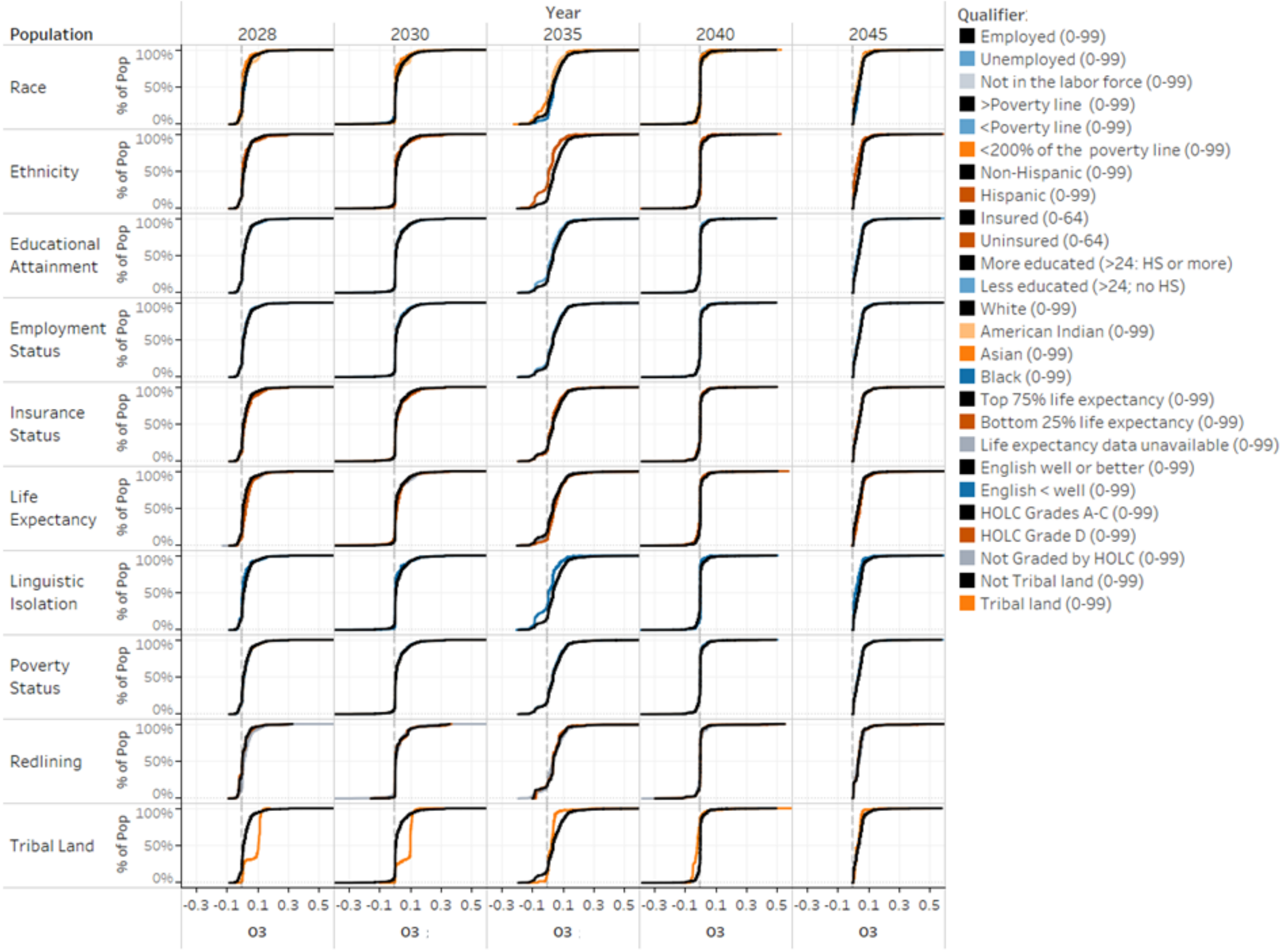

Figure C-7 Distributions of Ozone Concentration Changes (ppb) Across Populations, Future Years for the Alternative 1 Scenario

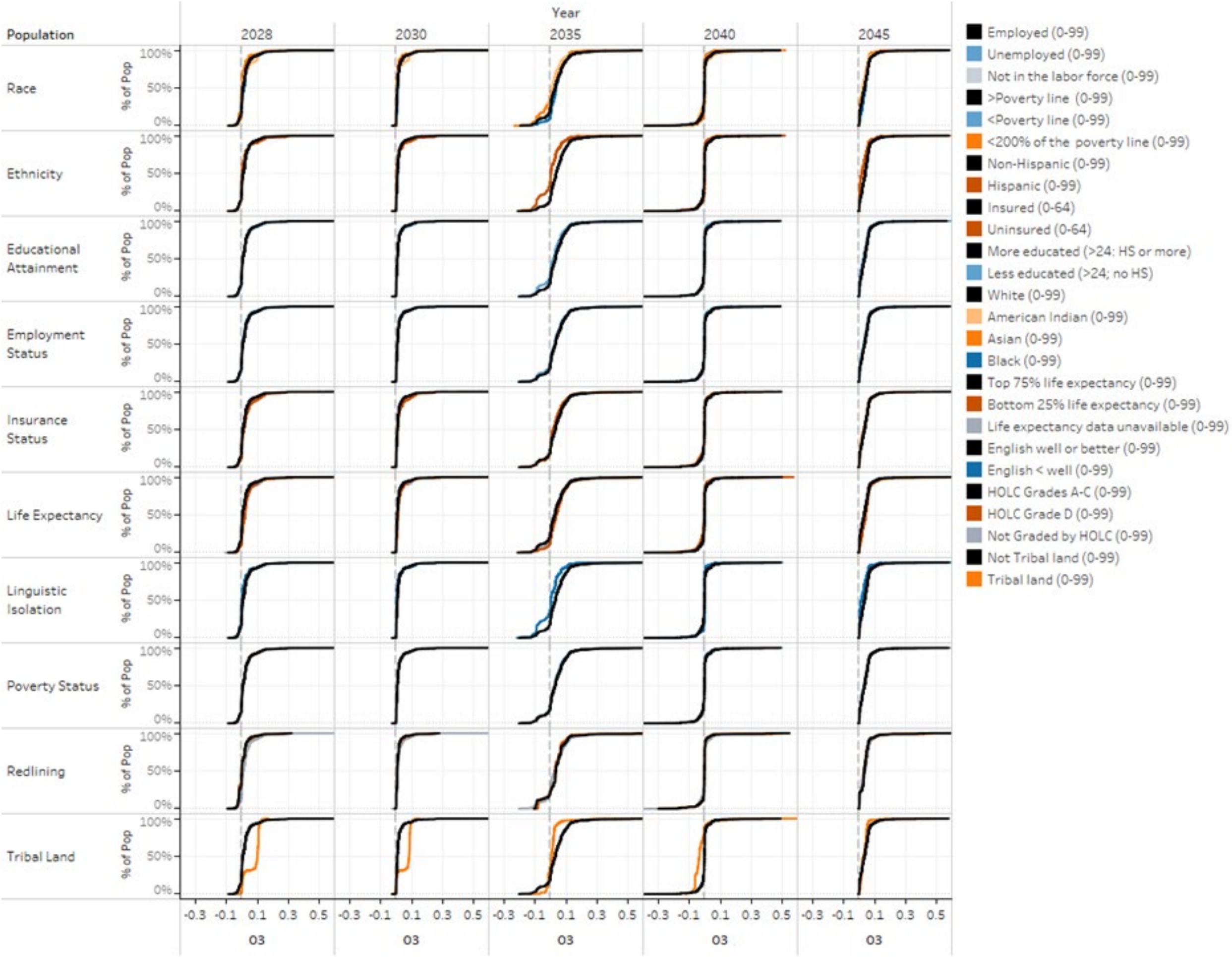

Figure C-8 Distributions of Ozone Concentration Changes (ppb) Across Populations, Future Years for the Alternative 2 Scenario

APPENDIX D: ASSESSMENT OF POTENTIAL COSTS AND EMISSIONS IMPACTS OF FINAL NEW AND EXISTING SOURCE STANDARDS ANALYZED SEPARATELY

D.1 Modeling the Rules Independently

In this appendix, we describe the projected EGU compliance behavior, costs, and emissions impacts for the final Emission Guidelines and final NSPS when modeled independently. We also compare the results from each rule modeled individually with the results presented elsewhere in the RIA that shows the final rules combined effects. This supplementary analysis quantifies the climate benefits of these rules but does not quantify any additional benefits, for instance health benefits from reductions in other pollutants, because of time and resource constraints. The GHG mitigation measures modeled under each of these scenarios are consistent with those applicable to each source category under the final rules, as outlined in Table D-1 and Table D-2.

Table D-1 Summary of GHG Mitigation Measures for Existing Sources by Source Category under the Final Rules[a,b,c]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations by 2040	CCS with 90% capture of CO_2, starting in 2035
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units that have not elected to commit to permanently cease operations prior to 2035, but have committed to permanently ceasing operations prior to 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.

[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.

[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

Table D-2 Summary of Modeled GHG Mitigation Measures for New Sources by Source Category under the Final Rule[a,b,c]

Affected EGUs	Subcategory Definition	Modeled Requirements during 1st Phase	Modeled Requirements During 2nd Phase (2035)	Baseload Definition
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at greater than baseload annual capacity factor	Efficient generation	CCS or co-fire hydrogen at sufficient level to meet CCS emission rate	40%
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than baseload	Efficient generation		
Intermediate load Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of more than 40%	Emission rate consistent with NGCC operation		
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 40%	Efficient generation		

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER, details of which are available in Section VII of the preamble.

[b] Delivered hydrogen price is assumed to be $1.15/kg in all years.

[c] The modeling does not reflect the requirements of the variable subcategory. We estimate this would have a limited impact on the results.

D.2 Compliance Cost Assessment

The estimates of incremental costs of supplying electricity under the final rules and under the final Emission Guidelines and final NSPS when modeled separately are presented in Table D-3. Estimates for additional recordkeeping, monitoring, and reporting requirements for EGUs are also included within the estimates in this table.

Table D-3 National Power Sector Compliance Cost Estimates for the Illustrative Scenarios (billions of 2019 dollars)

	Final	New Source Rule Only	Existing Source Rule Only
2024 to 2042 (Annualized)	0.43	0.14	0.52
2024 to 2047 (Annualized)	0.86	0.14	0.94
2028 (Annual)	-1.30	-0.05	-0.80
2030 (Annual)	-0.22	0.06	0.41
2035 (Annual)	1.28	-0.35	1.03
2040 (Annual)	0.59	-0.17	0.74
2045 (Annual)	3.34	-0.13	3.34

"2024 to 2042 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2042 and discounted using a 3.76 real discount rate.[215] This does not include compliance costs beyond 2042. "2024 to 2047 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2047 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2047. "2028 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those run years.[216]

Existing coal-fired EGUs represent the largest share of affected resources within the final rules. Hence the existing source rule is responsible for the majority of cost increases projected under the final (combined effect) rule. New sources represent a smaller total share of the affected sources under this rule, and hence cost increases projected under the final NSPS alone are smaller than under the existing source rule.

Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2030 run year on some coal-fired EGUs that currently lack them. Under the scenarios modeled, a subset of these facilities retires rather than retrofit, since they would face additional requirements under the GHG regulations modeled. This in turn results in lower capital costs in the first run year and is balanced by higher costs in later years. Additionally, renewable costs are assumed to decline over the forecast period. Given IPM's perfect foresight, the model choses to wait to build incremental RE until later in the period when costs are lower. Under the illustrative policy

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[215] This table reports compliance costs consistent with expected electricity sector economic conditions. The PV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. The PV of costs was then used to calculate the levelized annual value over a 19-year period (2024 to 2042) and a 23-year period (2024 to 2047) using the 3.76 percent rate as well. Tables ES-19 and 8-4 report the PV of the annual stream of costs from 2024 to 2047 using 3 percent and 7 percent consistent with OMB guidance.

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

scenarios the model builds this capacity sooner, which results in lower costs in the years built, but higher costs in future years.

D.3 Emissions Reduction Assessment

As indicated in Section 3, the CO_2 emissions reductions are presented in this RIA from 2028 through 2045 and are based on IPM projections. Table D-4 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the final rule requirements, as well as the estimated emissions from the final Emission Guidelines and final NSPS independently.

The CO_2 emission reductions follow an expected pattern: the existing source rule is responsible for the majority of reductions under the final rules modeling presented in the RIA, and these reductions occur primarily in the first half of the forecast period. The new source rule is responsible for a smaller share of reductions, and these reductions occur more towards the latter half of the forecast period. Cumulative CO_2 reductions between 2028-47 under the final rules (1.382 billion metric tons) are greater than under the existing source rule only (1.332 billion metric tons) and under the final NSPS only (an increase of 15 million metric tons). Under the New Source Rule only, CO_2 emissions at new sources declines, but these are offset by increases at existing sources, particularly in 2035. By 2040 reductions at new sources begin to match increases in emissions at existing sources, and in 2045 reductions at new sources outweigh increases at existing sources. Under the Existing Source Rule only, emissions from existing sources are lower, and only partially offset by increases in emissions from new sources, resulting in net emission decreases over the forecast period.

Table D-4 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Scenarios from 2028 to 2045[217]

Annual CO_2	Total Emissions				Change from Baseline		
(million metric tons)	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	1,159	1,121	1,162	1,121	-38	3	-38
2030	1,098	1,048	1,100	1,050	-50	2	-49
2035	724	601	729	600	-123	5	-125
2040	459	406	459	411	-54	0	-48
2045	307	265	303	271	-42	-4	-36
Cumulative (2028-47)	12,538	11,156	12,553	11,206	-1,382	15	-1,332

There will also be impacts on non-CO_2 air emissions associated with EGUs burning fossil fuels that result from compliance strategies modeled to meet the requirements of the final rules. These other emissions include changes in emissions of NO_X, SO_2, and direct $PM_{2.5}$ emissions changes, as well as changes in ozone season NO_X emissions. The emissions impacts are presented in Table D-5.

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

Table D-5 EGU Annual Emissions and Emissions Changes for Annual NO_X, Ozone Season (April to September) NO_X, SO_2, and Direct $PM_{2.5}$ for the Baseline and Illustrative Scenarios for 2028 to 2040

Annual NO_X	Total Emissions				Change from Baseline		
(Thousand Tons)	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	461	441	465	439	-20	5	-22
2030	393	374	396	372	-20	3	-22
2035	259	210	266	204	-49	7	-55
2040	173	166	174	165	-6	2	-7
2045	107	83	107	83	-24	1	-24

Ozone Season NO_X[a]	Total Emissions				Change from Baseline		
(Thousand Tons)	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	189	183	191	182	-6	2	-7
2030	175	168	176	167	-7	1	-8
2035	119	100	122	96	-19	3	-23
2040	88	82	89	81	-6	2	-7
2045	59	45	59	45	-14	0	-14

Annual SO_2	Total Emissions				Change from Baseline		
(Thousand Tons)	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	454	420	461	424	-34	7	-30
2030	334	313	335	318	-20	2	-15
2035	240	150	244	150	-90	4	-90
2040	143	139	143	139	-4	1	-4
2045	55	13	53	13	-41	-1	-41

Direct $PM_{2.5}$	Total Emissions				Change from Baseline		
(Tons)	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	71	69	71	69	-2	0	-2
2030	66	65	66	65	-2	0	-1
2035	51	49	52	49	-1	1	-2
2040	37	39	38	39	2	0	1
2045	24	22	24	22	-2	0	-2

[a] Ozone season is the May through September period in this analysis.

D.4 Impacts on Fuel Use and Generation Mix

The final NSPS and final Emission Guidelines expected to result in significant GHG emissions reductions. They are also expected to have impacts on the power sector. Consideration of these potential impacts is an important component of assessing the relative impact of the illustrative scenarios. In this section we discuss the estimated changes in fuel use, fuel prices, generation by fuel type, and capacity by fuel type for the 2030, 2035, 2040 and 2045 IPM model run years under the final rules and under the final Emission Guidelines and final NSPS independently.

As outlined in Table D-6, under the final existing source rule only, coal consumption falls more than under the final rules, while coal consumption falls least under the final new source rule only. Under the existing source rule only, GHG mitigation measures apply to existing coal-fired EGUs as outlined in Table D-1. Hence coal capacity reductions are offset by increases in new source NGCC generation. Under the new source rule-only modeling, the GHG mitigation measures apply only to new fossil-fuel fired sources, as outlined in Table D-2. Hence generation and emissions from these sources falls and are compensated for by increases in generation and emissions from existing sources.

Table D-6 2028, 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use for the Baseline and the Illustrative Scenarios

		Million Tons				Percent Change from Baseline		
	Year	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
Appalachia	2028	40	37	42	35	-7%	6%	-11%
Interior		38	35	39	35	-7%	4%	-6%
Waste Coal		7	7	7	7	0%	0%	0%
West		166	155	164	157	-7%	-1%	-6%
Total		251	234	253	235	-7%	1%	-6%
Appalachia	2030	39	39	39	39	0%	0%	0%
Interior		35	36	38	34	1%	7%	-3%
Waste Coal		7	7	7	7	0%	0%	0%
West		141	113	139	115	-20%	-1%	-18%
Total		222	194	223	195	-13%	0%	-12%
Appalachia	2035	32	19	34	19	-40%	7%	-40%
Interior		19	25	21	25	30%	6%	30%
Waste Coal		7	3	7	3	-53%	0%	-53%
West		89	63	88	63	-29%	-1%	-29%
Total		147	111	150	111	-25%	2%	-25%
Appalachia	2040	19	19	20	19	1%	3%	1%
Interior		10	25	10	25	150%	0%	150%
Waste Coal		3	3	3	3	0%	0%	0%
West		61	56	60	56	-8%	0%	-8%
Total		93	103	93	103	11%	0%	11%
Appalachia	2045	4	0	4	0	-100%	9%	-100%
Interior		1	0	1	0	-100%	0%	-100%
Waste Coal		3	0	3	0	-100%	0%	-100%
West		20	3	20	3	-85%	0%	-85%
Total		28	3	28	3	-89%	1%	-90%

As outlined in Table D-7 gas consumption follows the opposite trend to coal consumption under the three scenarios shown. Under the existing source rule, gas consumption remains at similar levels to the final rules (gas generation compensates for declining coal generation), while under the new source rule, gas generation is moderately lower as a result of GHG mitigation measures applied to new fossil-fuel fired sources, while similar measures are not applied to existing coal-fired sources.

Table D-7 2028, 2030, 2035, 2040 and 2045 Projected Power Sector Natural Gas Use for the Baseline and the Illustrative Scenarios

	Trillion Cubic Feet				Percent Change from Baseline		
Year	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
2028	11.6	11.5	11.5	11.5	-1.0%	-0.6%	-1.0%
2030	11.7	11.7	11.7	11.7	0.0%	0.0%	0.0%
2035	9.3	9.7	9.3	9.6	4.3%	-0.1%	4.1%
2040	6.4	6.4	6.4	6.5	-0.1%	-0.1%	1.0%
2045	4.2	4.3	4.2	4.4	1.1%	-1.8%	3.0%

As outlined in Table D-8 and Table D-9 coal and gas prices are similar under the final rules and Existing Source rules, while changes are smaller under the final NSPS.

Table D-8 2028, 2030, 2035 and 2040 Projected Minemouth and Power Sector Delivered Coal Price (2019 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				Percent Change from Baseline		
		Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
Minemouth	2028	0.98	0.97	0.99	0.96	-1%	1%	-1%
Delivered		1.54	1.52	1.56	1.52	-1%	1%	-2%
Minemouth	2030	1.02	1.05	1.03	1.04	3%	1%	2%
Delivered		1.56	1.53	1.57	1.53	-2%	1%	-2%
Minemouth	2035	1.07	1.10	1.08	1.10	3%	1%	3%
Delivered		1.55	1.55	1.56	1.55	0%	1%	0%
Minemouth	2040	1.17	1.22	1.17	1.21	4%	0%	3%
Delivered		1.59	1.60	1.60	1.60	1%	0%	0%
Minemouth	2045	1.37	1.50	1.37	1.50	9%	0%	9%
Delivered		1.38	0.94	1.39	0.95	-32%	1%	-31%

Table D-9 2028, 2030, 2035 and 2040 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2016 dollars) for the Baseline and the Illustrative Scenarios

		$/MMBtu				Percent Change from Baseline		
		Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
Henry Hub	2028	2.78	2.72	2.78	2.76	-2%	0%	-1%
Delivered		2.84	2.78	2.84	2.82	-2%	0%	-1%
Henry Hub	2030	2.89	2.90	2.89	2.95	0%	0%	2%
Delivered		2.95	2.97	2.96	3.01	1%	0%	2%
Henry Hub	2035	2.87	2.95	2.82	2.95	3%	-2%	3%
Delivered		2.88	2.97	2.83	2.97	3%	-2%	3%
Henry Hub	2040	2.82	2.79	2.77	2.83	-1%	-2%	1%
Delivered		2.79	2.77	2.75	2.81	-1%	-2%	1%
Henry Hub	2045	2.95	2.95	2.91	3.00	0%	-1%	2%
Delivered		2.94	2.94	2.89	2.98	0%	-2%	2%

As outlined in Table D-10 the generation mix remains generally similar under the final and existing source rules, but the non-imposition of GHG mitigation measures on new fossil-fired sources under the existing source rule only scenario results in some increase in generation from new NGCC capacity relative to the final. Under the new source only scenario, the overall generation mix is similar to the baseline, with the exception of higher coal dispatch driven by the GHG mitigation measures on new fossil-fired sources reducing the total dispatch of new NGCC units.

Table D-10 2028, 2030, 2035 and 2040 Projected U.S. Generation by Fuel Type for the Baseline and the Illustrative Scenarios

		Generation (TWh)				Percent Change from Baseline		
	Year	Baseline	Final	New Source Rule Only	Existing Source Rule Only	Final	New Source Rule Only	Existing Source Rule Only
Unabated Coal	2028	472	441	480	441	-7%	2%	-7%
Coal & CCS		0	0	0	0	-	-	-
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		1,652	1,631	1,636	1,642	-1%	-1%	-1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		751	751	751	751	0%	0%	0%
Hydro		293	293	293	292	0%	0%	0%

Non-Hydro RE		1,141	1,191	1,148	1,182	4%	1%	4%
Oil/Gas Steam		26	28	27	25	8%	7%	-1%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,365	4,366	4,366	4,364	0%	0%	0%
Unabated Coal	2030	407	355	409	356	-13%	1%	-12%
Coal & CCS		3	5	3	5	71%	0%	76%
Coal & Nat. Gas co-firing		0	2	0	2	-	-	-
Unabated Nat. Gas		1,670	1,660	1,660	1,674	0%	0%	1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		729	729	729	729	0%	0%	0%
Hydro		298	299	298	298	0%	0%	0%
Non-Hydro RE		1,329	1,381	1,335	1,370	4%	0%	3%
Oil/Gas Steam		25	28	26	25	12%	8%	0%
Other		31	31	31	31	0%	0%	0%
Grand Total		4,491	4,491	4,491	4,490	0%	0%	0%
Unabated Coal	2035	160	0	166	0	-100%	4%	-100%
Coal & CCS		76	133	76	133	74%	0%	74%
Coal & Nat. Gas co-firing		0	4	0	4	-	-	-
Unabated Nat. Gas		1,341	1,379	1,321	1,398	4%	-1%	5%
Nat. Gas & CCS		3	7	7	2	105%	105%	-37%
Nuclear		667	666	667	666	0%	0%	0%
Hydro		319	317	318	317	-1%	0%	-1%
Non-Hydro RE		2,229	2,286	2,238	2,273	3%	0%	2%
Oil/Gas Steam		8	9	8	9	21%	4%	14%
Other		31	30	31	30	0%	0%	0%
Grand Total		4,834	4,831	4,831	4,833	0%	0%	0%
Unabated Coal	2040	61	0	62	0	-100%	2%	-100%
Coal & CCS		76	128	76	128	68%	0%	68%
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		933	919	918	947	0%	-1%	3%
Nat. Gas & CCS		3	7	7	2	105%	105%	-37%
Nuclear		614	613	614	613	0%	0%	0%
Hydro		336	336	337	335	0%	0%	0%
Non-Hydro RE		3,097	3,119	3,108	3,095	1%	0%	0%
Oil/Gas Steam		5	6	5	6	28%	2%	26%
Other		29	29	29	29	0%	0%	0%
Grand Total		5,154	5,157	5,155	5,155	0%	0%	0%
Unabated Coal	2045	45	0	46	0	-100%	2%	-100%

Coal & CCS		4	3	4	3	-7%	0%	-8%
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		614	612	595	635	1%	-2%	5%
Nat. Gas & CCS		3	6	6	2	103%	100%	-42%
Nuclear		471	472	471	474	0%	0%	1%
Hydro		343	342	343	342	0%	0%	0%
Non-Hydro RE		4,032	4,089	4,048	4,066	1%	0%	1%
Oil/Gas Steam		4	6	5	6	25%	1%	24%
Other		28	27	28	27	0%	0%	0%
Grand Total		5,544	5,557	5,544	5,555	0%	0%	0%

As outlined in Table D-11 the capacity mix follows similar trends to those seen under the generation mix table. The capacity mix under the final and existing source rule scenarios are similar, while the capacity mix under the baseline and new source rule only scenarios are similar. The new source rule only is projected to result in less new NGCC and more existing coal capacity relative to the baseline, while the existing source rule only is projected to result in less coal capacity and more new NGCC capacity relative to the projected final results.

Table D-11 2028, 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type for the Baseline and the Illustrative Scenarios

		Capacity (GW)				Percent Change from Baseline		
	Year	**Baseline**	**Final**	**New Source Rule Only**	**Existing Source Rule Only**	**Final**	**New Source Rule Only**	**Existing Source Rule Only**
Unabated Coal	2028	106	101	108	98	-4%	2%	-7%
Coal & CCS		0	0	0	0	-	-	-
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		471	472	467	476	0%	-1%	1%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		94	94	94	94	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		394	407	396	404	3%	1%	3%
Oil/Gas Steam		63	64	62	64	2%	0%	2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,236	1,246	1,236	1,245	1%	0%	1%

Unabated Coal	2030	85	72	85	70	-15%	1%	-18%
Coal & CCS		0	1	0	1	72%	0%	77%
Coal & Nat. Gas co-firing		0	1	0	1	-	-	-
Unabated Nat. Gas		479	480	475	484	1%	0%	2%
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		91	91	91	91	0%	0%	0%
Hydro		104	104	104	104	0%	0%	0%
Non-Hydro RE		440	454	443	450	3%	1%	2%
Oil/Gas Steam		64	73	64	73	13%	0%	13%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,269	1,281	1,269	1,279	1%	0%	1%
Unabated Coal	2035	41	0	42	0	-100%	4%	-100%
Coal & CCS		11	19	11	19	74%	0%	74%
Coal & Nat. Gas co-firing		0	1	0	1	-	-	-
Unabated Nat. Gas		476	484	472	486	2%	0%	2%
Nat. Gas & CCS		0	1	1	0	104%	104%	-36%
Nuclear		84	84	84	84	0%	0%	0%
Hydro		107	107	107	107	0%	0%	0%
Non-Hydro RE		699	714	701	710	2%	0%	2%
Oil/Gas Steam		55	66	55	65	19%	0%	18%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,479	1,482	1,480	1,479	0%	0%	0%
Unabated Coal	2040	31	0	31	0	-99%	0%	-99%
Coal & CCS		11	18	11	18	68%	0%	68%
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		516	525	515	526	2%	0%	2%
Nat. Gas & CCS		0	1	1	0	104%	104%	-36%
Nuclear		79	79	79	79	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		943	952	947	944	1%	0%	0%
Oil/Gas Steam		54	65	54	64	19%	0%	19%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,753	1,759	1,758	1,751	0%	0%	0%
Unabated Coal	2045	29	0	29	0	-99%	1%	-99%
Coal & CCS		1	1	1	1	-5%	0%	-7%
Coal & Nat. Gas co-firing		0	0	0	0	-	-	-
Unabated Nat. Gas		565	581	563	583	3%	0%	4%

Nat. Gas & CCS		0	1	1	0	104%	104%	-36%
Nuclear		65	65	65	65	0%	0%	0%
Hydro		112	112	112	112	0%	0%	0%
Non-Hydro RE		1,232	1,250	1,238	1,242	1%	0%	1%
Oil/Gas Steam		54	64	54	64	19%	0%	19%
Other		7	7	7	7	0%	0%	0%
Grand Total		2,065	2,080	2,069	2,073	1%	0%	0%

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